Appendix 37

Asset management reports supporting identified projects

1. Communication Cables – Asset Management Report YE 2012
2. Protection Systems – Asset Management Report YE 2012
3. HV and LV Switchgear – Asset Management Report YE 2012
4. High Voltage Circuit Breakers – Asset Management Report YE 2012
5. Voltage Regulators – Asset Management Report YE 2012
6. Power Transformers – Asset Management Report YE 2012
7. Distribution Transformers – Asset Management Report YE 2012
8. 11kV Overhead Lines – Asset Management Report YE 2012
9. Low Voltage Overhead Lines – Asset Management Report YE 2012
10. Substations – Asset Management Report YE 2012
11. Network Related Property – Asset Management Report YE 2012
12. 66kV Underground Cables – Asset Management Report YE 2012
13. 33kV Underground Cables – Asset Management Report YE 2012
14. 11kV Underground Cables – Asset Management Report YE 2012
15. Low Voltage Underground Cables – Asset Management Report YE 2012
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19. Metering – Asset Management Report YE 2012
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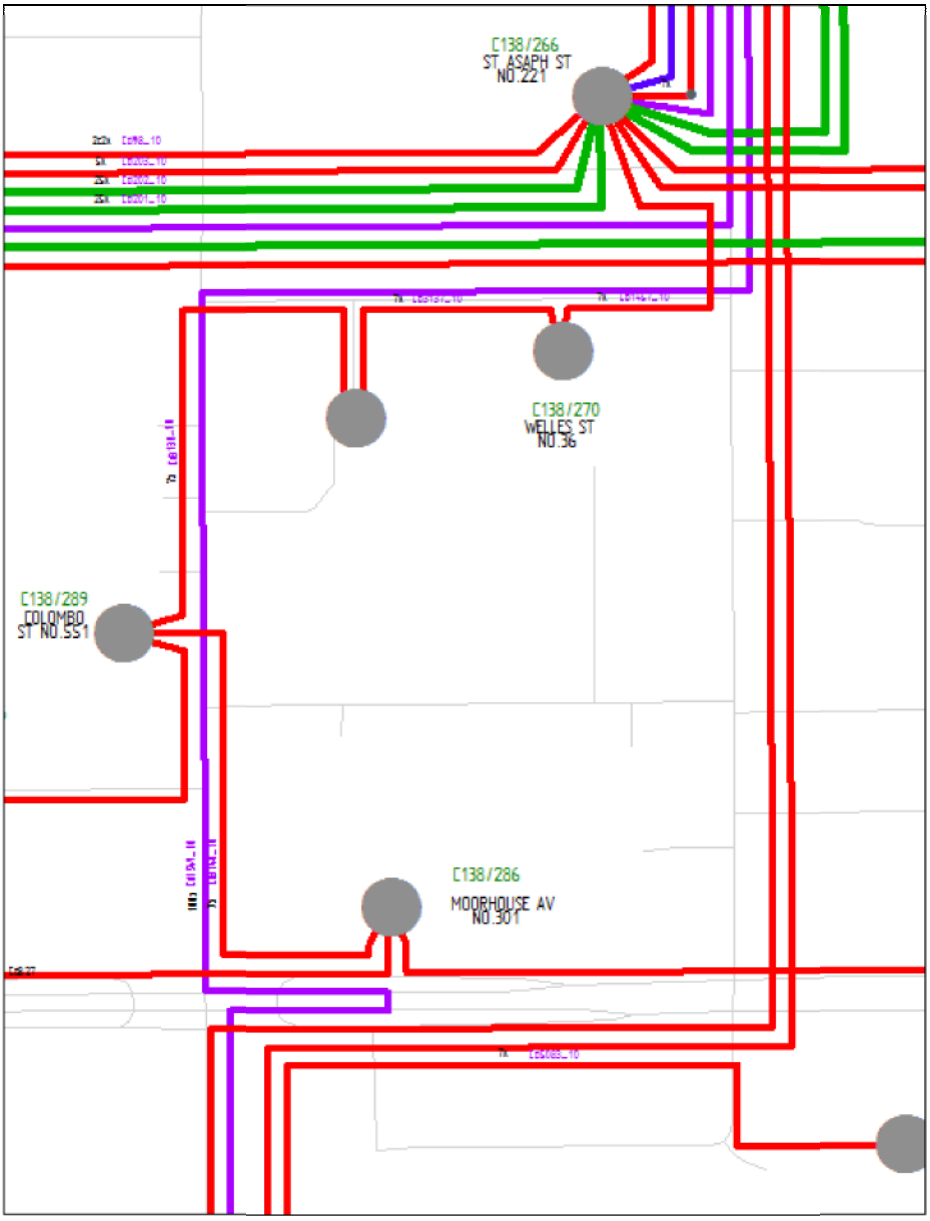
Communication Cables

Asset Management Report YE 2012



NW70.00.28

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1 INTRODUCTION

This document covers our network of underground communication cables that are primarily used for protection signalling, but also carry ancillary services either back to the main office or between substations as required. It details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these cables.

2 ASSET DESCRIPTION

2.1 GENERAL

Our communication cable network is 1,253 km of circuit length and is largely concentrated in the urban area of Christchurch. The earlier cables are paper lead. Plastic insulation was introduced in the 1960s to replace some paper lead cables.

We have 496 distribution cabinets installed on our communication cable network. These are located within either our network or zone substations, with only 39 of these cabinets mounted on the roadside. Sufficient cabinets are needed to allow the system to be reconfigured in the event of component failure or other requirements. Distribution cabinets are all above ground and generally of steel construction.

Figure 1: Underground Communication Cables

Conductor	Length (m)	Length (km)	Avg Yr Install	Avg Age (Yrs)
10^{X}	29,805	29.80	1977	35
12c	7,595	7.60	2000	12
12^{X}	1,497	1.50	2007	5
15^{X}	13,570	13.57	1980	32
1c	286	0.29	1979	33
1^{X}	941	0.94	1958	54
2c	51,344	51.34	1958	54
$2c/1^{X}$	220	0.22	1972	41
$2c/2^{X}$	74,775	74.77	1966	46
2^{X}	814	0.81	1964	48
$2^{X}\ 15^{X}$	1	0.00	1991	21
$2^{X}\ 15^{X}\ 25^{X}$	1	0.00	1991	21
$2^{X}\ 10^{X}\ 5^{X}$	396	0.40	1969	43
$2^{X}\ 25$	56	0.06	1958	54
3c	37,217	37.22	1950	62
3^{X}	6,872	6.87	1967	45
4c	7,334	7.33	1999	13
4^{X}	2,034	2.03	2008	4
5^{X}	22,973	22.97	1968	44
6C	12,782	12.78	1968	44
7C	1,069	1.07	1971	41
DTS	2,576	2.58	2008	4
Total	**274,156**	**274.16**		**34**
Overall	**1,253,202**	**1,253.20**		**34**

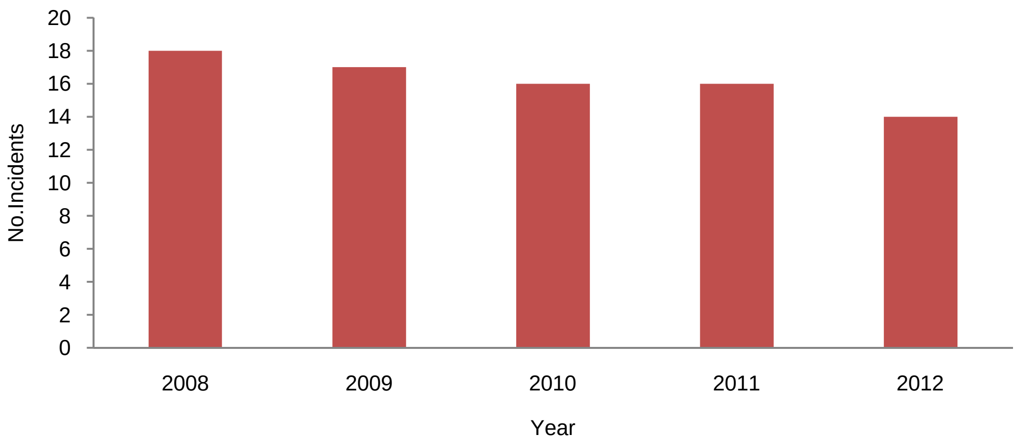
3 ASSET PERFORMANCE

The configuration of the communication cable network has in the past where possible been laid between substation distribution boxes. This arrangement provides the greatest flexibility and usage of the network. The cable is buried directly in the ground. Jointing methods and cable construction methods have been changed to improve performance.

The September 2010 and February 2011 earthquakes caused a number of communication cable faults. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale.

The M6.3 earthquake in June 2011 caused limited further damage to our communication cables and had little impact on our recovery programme.

Figure 2: Communication Cable Performance



As the communication cable network carries protection and ancillary services, it is possible that failures do not present themselves until sometime after the actual failure has occurred. Due to this, it is unlikely that our fault statistics accurately capture either the number or cause of the failures. To date the majority of failure modes have included:

- third party damage
- damage of cable during installation or other disturbance causing premature failure.

To manage these issues the following actions are taken:

- proactive promotion of cable locating services to contractors
- inspection of contractors during cable laying
- cable is now required to have an orange coloured sheath to allow easier identification.

Figure 3: Failure Modes

	2008	2009	2010	2011	2012
Asset Failure	11	13	14	10	9
Miscellaneous	2	2	2	5	3
Third party	5	2		1	2
Vegetation	-	-	-	-	-
Weather / Environment	-	-	-	-	-
Total	18	17	16	16	14

4 ASSET CONDITION

4.1 GENERAL

Cable has been laid to a good standard and we are not at risk, to any great extent, from external damage but early jointing techniques have led to moisture being present in the joints which lowers the electrical properties of the cable.

We anticipate cables that have been subjected to earthquake stress will have higher failure rates over the next few years as faults develop in sheaths and insulation. To mitigate this we will test the cables in identified areas over the next few years to determine whether maintenance or replacement is required.

The above-ground cable distribution boxes are in reasonable condition due to their majority location within substations.

4.2 HISTORICAL ISSUES

Communication cables not used can deteriorate without our knowledge and we only become aware of their condition when we want to utilise them.

Accuracy of our records has led to delays in carrying out works utilising communication cables.

4.3 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011, EA Technology Ltd was engaged to develop condition based risk management (CBRM) models for the majority of our asset groups. Communication cables were not included as part of this project as we were undertaking a review of our asset management practices for communication and control systems. The earthquakes have further delayed this review, however it is envisioned that we will develop CBRM models for these assets in the near future.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

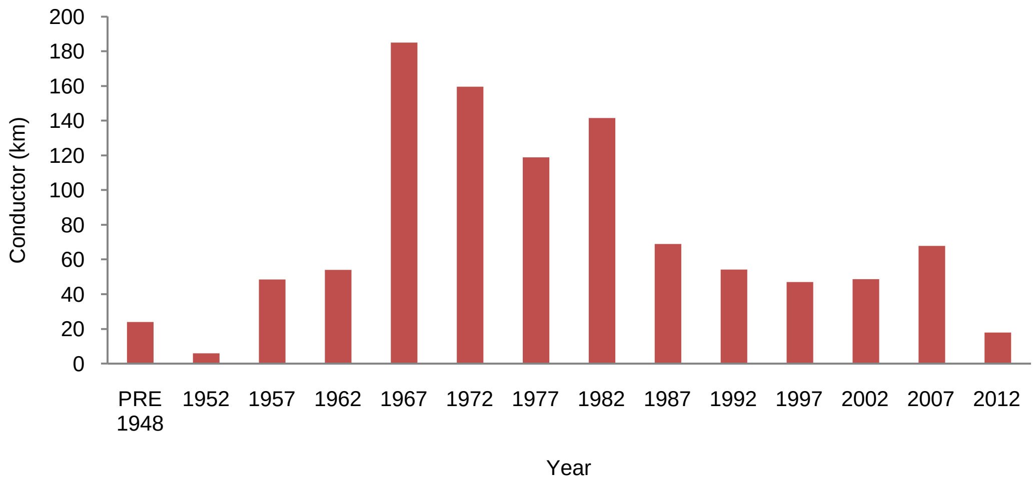
We employ a number of different asset management practices for different asset groups.

- Cables – Installation and Maintenance NW72.22.01. The purpose of this specification is to set out standards for the installation and maintenance of all cable groups including communications.
- Cables – Testing NW72.23.24. The purpose of this specification is to set out standards for the testing requirements of all cable groups including communications.
- 11kV Unit Protection Maintenance Tests – NW72.27.01. The purpose of this specification is to set out standards for the testing requirements of unit protection which utilises the communication cable network.
- Draughting and Records NW70.50.02. The purpose of this standard is to set out how we record our communication cable installation and connections.

5.2 COMMUNICATION CABLES LIFECYCLE

The average age of our communications cable is 40 years. The overall condition of these cables is good; however we are expecting an increase in the failure rates for cables in the eastern suburbs. We have developed a programme to test cables in this area to determine if the expected life of these assets has been affected.

Figure 4: Age Profile - Communication Cables



5.3 MAINTENANCE PLAN

No specific maintenance plan is employed for the communication cables at this stage. During the course of works when faults are identified a repair strategy is implemented.

5.4 REPLACEMENT PLAN

Renewal of communication cables is based on condition results from tests carried out during the installation and commissioning of other works.

5.5 DISPOSAL PLAN

We have no plans to dispose of any of this asset, other than minor disposals associated with changes and rearrangements in the network.

5.6 CREATION / ACQUISITION PLAN

We will install additional communication cables based on assessment of need in a particular area. When other cables are being laid decisions will be made to install fibre duct only or fibre and fibre duct. This method reduces the sunken cost of the communication network.

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

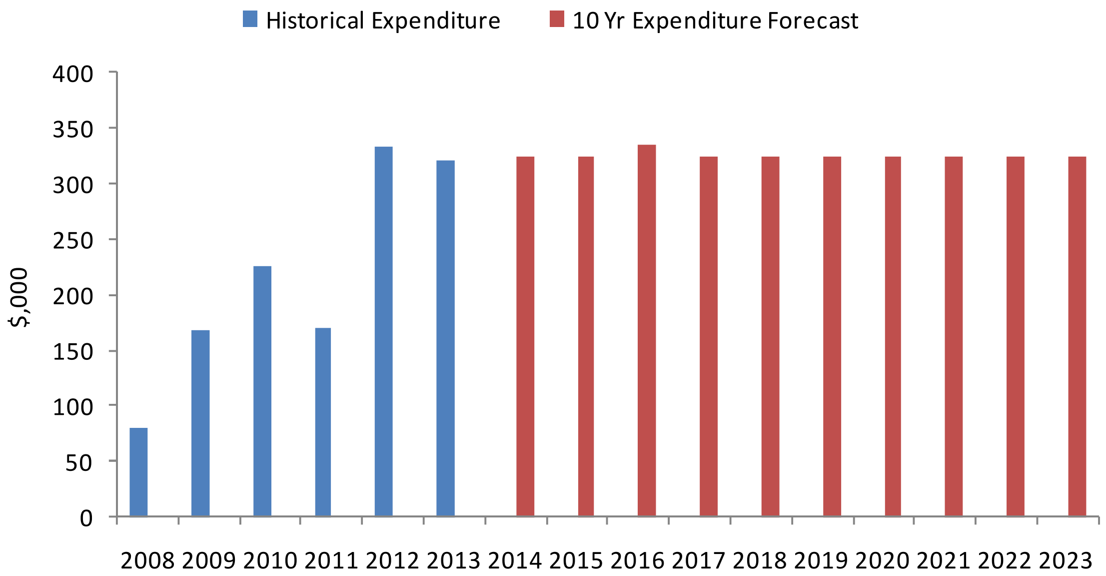
By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 5: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 6: Historical Communication Cable Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	42	75	132	99	34	225
Non-Scheduled	25	81	69	58	52	80
Emergency	13	12	25	13	247	15
Total	**80**	**168**	**226**	**170**	**333**	**320**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 7: Communication Cable Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	225	225	225	225	225	225	225	225	225	225
Non-Scheduled	80	80	80	80	80	80	80	80	80	80
Emergency	20	20	30	20	20	20	20	20	20	20
Total	**325**	**325**	**335**	**325**	**325**	**325**	**325**	**325**	**325**	**325**

Our scheduled communication cable maintenance is tendered out using our contracting model.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 8: Historical and Forecast Expenditure

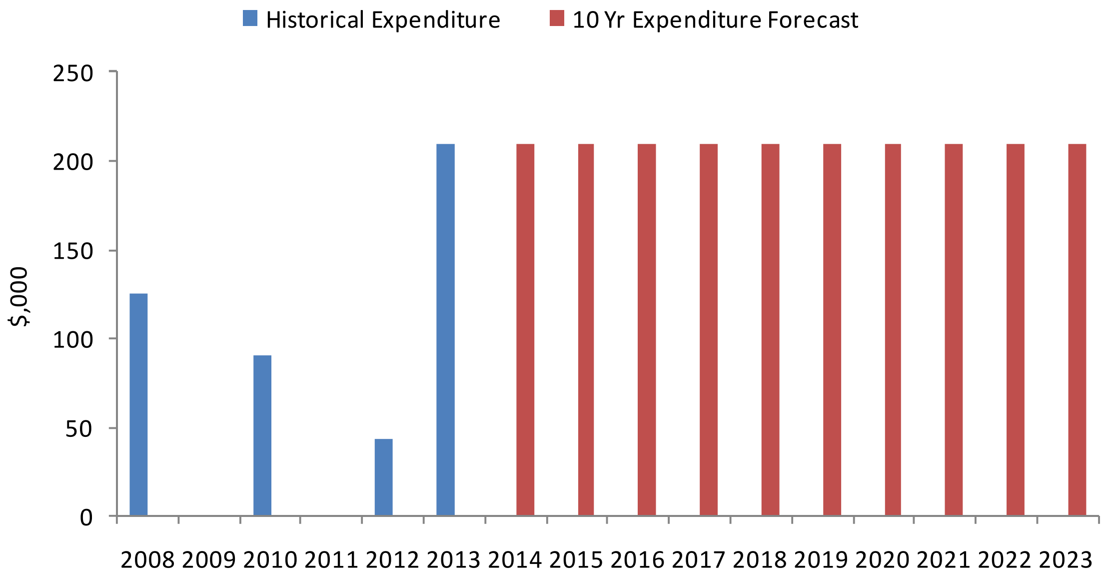


Figure 9: Historical Communication Cable Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	125	0	91	0	43	210
Total	**125**	**0**	**91**	**0**	**43**	**210**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 10: Communication Cable Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	210	210	210	210	210	210	210	210	210	210
Total	**210**	**210**	**210**	**210**	**210**	**210**	**210**	**210**	**210**	**210**

We have allowed for the replacement of approximately 4km of communication cables in the earthquake affected areas. As we analyse our fault data and maintenance results, we will refine the replacement programme as appropriate.

Protection Systems

Asset Management Report YE 2012

NW70.00.22

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INTRODUCTION

Protection systems are installed to protect the network during power systems faults. These systems protect all levels of the network except the low voltage system where fuses are used.

This document covers our protection systems and details the criteria and asset management practices used to ensure Orion obtains effective performance and acceptable service levels.

1 ASSET DESCRIPTION

1.1 GENERAL

Historically, substation protection, control and metering functions were performed with electro-mechanical equipment. This electro-mechanical equipment has been superseded firstly by analogue electronic equipment, most of which emulates the single-function approach of their predecessors. More recently, digital electronic equipment has begun to provide protection, control and metering functions. The functions performed by these digital devices are so wide they have been labelled Intelligent Electronic Devices (IED).

Along with IEDs the introduction of Merging Units (Bricks) has created a paradigm shift in protection system architecture. Traditionally a dedicated protection relay, ancillary equipment and multi-core copper cabling were required for each scheme. IEDs reduced the amount of hardware mounted on control panels but hard wired copper connections were still required between the primary plant, protection relays and station Remote Terminal Unit RTU. This copper cabling is now replaced by fibre optic cables.

Along with the introduction of IEDs Orion moved to reduce costs by improving personnel productivity and increasing system reliability and efficiency. The introduction of remote I/O reduces labour requirements, engineering design, installation and commissioning. Operation of the system is based on existing skill sets and does not require any significant changes in the organisation.

Relay setting data is now held in a proprietary settings database (StationWare). This system provides a data-warehouse to store settings. Ongoing work is required to review settings as the network architecture changes with growth and alterations.

1.2 PROTECTION SYSTEMS

1.2.1 Subtransmission Feeders 66kV and 33kV

Our subtransmission feeders mostly run point-to-point i.e. GXP to zone substation or zone substation to zone substation. In some cases we have a three ended configuration when a feeder to a zone substation is teed off a point to point feeder.

We provide the main protection on GXP feeders with Transpower providing backup protection. We are also responsible for checking and confirming that the backup protection is adequate for our needs. In most cases the subtransmission circuits have unit protection (line-differential). In cases where this is not practical directional over-current and earth-fault elements are utilised.

1.2.2 Zone Substations

- Transformers

We have standard protection schemes we apply to transformers larger than 2MVA. These are:

- overall-differential protection
- restricted earth-fault on the secondary
- over-current/earth-fault on both the HV and LV windings

Most transformers come complete with mechanical protection in the form of a buchholz relay (for gassing in the oil), oil pressure relief and winding temperature.

- Busbars

In most cases our 66kV and 33kV busbar protection is accomplished by overlapping the zones of the line-differential protection and transformer-differential protection schemes. Where this is impractical a low impedance scheme is used. CB-fail is required in each of these cases.

- 11kV Circuit Breakers

11kV switchboards are fitted with a bus-zone protection scheme which includes CB-fail protection.

- 11kV Feeders

Our standard is to have two independent protection schemes to detect and clear all faults. This usually consists of unit protection and over-current. When there is no unit protection and the switchgear does not meet our arc containment standard, instantaneous over-current protection is used. Rural feeders that contain overhead lines have earth-fault protection. Special consideration is required were NERs and GFNs are installed.

1.2.3 Network Substations

To obtain protection co-ordination in the 11kV network it has been necessary to use differential or unit protection on all but the last radial sections of the 11kV distribution network.

It is not possible to use a dedicated communications provider’s network for unit protection. The unit protection signal levels are incompatible with normal commercial communications and in addition, it is not possible to obtain the very high reliability levels provided by a dedicated end–to-end cable laid with the power cable.

Radial overhead network feeders shall have over-current and earth-fault protection. The underground network requires over-current elements. As with zone substations, instantaneous over-current is set when switchgear that is not arc contained is connected to the feeder.

Network substations do not have busbar protection or CB-fail. The overreaching backup protection at the zone substation provides remote backup.

1.3 ASSET TYPES

1.3.1 Protection Relays

- Electro-mechanical Relays

These were widely used throughout the network until the introduction of electronic protective devices in the 1980s. They are very complex in construction and susceptible to vibration. However they are very robust electrically and continue to perform adequately in situations where fault levels and clearance times are not onerous e.g. some areas in the rural network. There have been occasions where electro-mechanical relays have not been suitable due to increased complexity of controlling the network and demand for “smart’ capabilities.

- Analogue Electronic Relays

Also known as 1st generation IEDs these relays are less susceptible to vibration and require less maintenance than their electromechanical counterparts. While they have slightly improved functionality and a smaller physical footprint, they are not capable of remote diagnostics via SCADA. Each of the individual protection elements are made up from discrete relay units.

- Digital Electronic Relays

These 2nd generation IEDs use microprocessor technology and are superior to their predecessors in many ways. Being microprocessor based means they are capable of performing multiple protection functions and provide a platform for remote diagnostics/control via SCADA. Storage of pre and post fault data for events has proven to be very useful in determining the cause of system faults.

While electronic relays have additional benefits, some consequences need to be considered, such as shorter lifecycles, software and firmware upgrades and increased standing load requirements on the substation battery bank.

- Merging Units (Bricks)

The Bricks are mounted in/on the appropriate circuit breaker and hardwired to any CT/VT inputs and CB indication & control circuits. A fibre-optic cable connects the Brick to the IED, allowing rapid data transfer immune to stray electromagnetic interference.

1.3.2 Communication Platforms

- UHF IP radio

UHF IP radio operating in a point-to-point configuration simultaneously uses the equipment to provide channels for both protection signalling, and Ethernet SCADA communications.

- Cable communications

Copper paired communications are extensively used with high–rate (HDSL) modems supporting data rates from 64kB/s through to 2MB/s. This network is extensive and is utilized (if copper pairs are available) for point-to-point links required for numeric unit protection.

- Fibre Optic Cable communications

We have recently started installing fibre optic rather that copper communication cables due to the better bandwidth capabilities that fibre provides.

1.3.3 Ground Fault Neutralisers

The Ground Fault Neutraliser (GFN) is used on our rural 11kV overhead line network. During a single phase earth-fault it displaces the neutral of the faulted phase to reduce the voltage to almost zero. The remaining un-faulted phases remain in service thus improving overall reliability and safety.

We have a programme to install GFNs in all of our rural zone substations.

For further details of the GFN refer to Orion’s Technical Specification NW72.13.108.

1.3.4 Neutral Earthing Resistors

These are simply a resistance that is installed in the supply transformer neutral that reduces the level of earth-fault current that can flow for single phase earth-faults. However they are only rated for short duration earth-faults and still required to be isolated by opening the circuit breaker. They were primarily installed where we had 33kV OH lines in urban areas but are now being removed when a GFN is installed.

1.3.5 Current and Voltage Transformers

The characteristics of our CTs and VTs are such that they match the ratings of the switchgear and transformers as well as the requirements of the protection scheme. We have a mixture of existing CTs and VTs, due to legacy equipment, which doesn't always suit new protections schemes. In these cases new CTs and VTs can be retrofitted to the existing primary plant.

New CTs and VTs installed in the network have the following characteristics:

Figure 1: CT Ratings

Voltage	CT Class	CT Rating
66kV	PX Class	1200 / 800 / 500 / 200 / 1A
33kV	PX Class	400 / 1A
11kV Incomer	7.5VA 5P20	2400 / 1200 / 1A*
11kV Bus Coupler	7.5VA 5P20	400 / 200 / 1A
11kV Feeder	7.5VA 5P20	1200 / 1A

*Must match the transformer rating

Figure 2: VT Ratings

Primary Voltage	VT Voltage	VT Rating
66kV	66kV / 110V	50VA 0.2 - 3P
33kV	33kV / 110V	50VA 0.5 - 3P
11kV	11kV / 110V	10VA 0.2 / 20 VA 6p

2 ASSET PERFORMANCE

2.1 GENERAL

The protection system has proven to be robust and performs well. The robustness can be attributed to planned maintenance and targeted replacement along with the introduction of modern technology using simplified design to avoid "traps" which can lead to human-error incidents. Protection schemes are designed to provide the required performance with as little complexity as possible. To improve performance, older electro-mechanical and analogue electronic devices have been replaced over time. Monitoring and remote access to many IEDs has reduced site visits and improved integrity.

Early bus-zone protection schemes, core-balance and fast-bus-blocking have proven to be problematic. Some of those schemes have now been replaced.

One minor risk area in our overall protection system is the communication cable network. All of our relays and primary plant are secure within the confines of our substations but the communication cable network is more exposed as it spread throughout the city. However, the number of incidents is minimal and we have a testing regime in place to mitigate any issues.

Safety of the public/workers, reliability and power quality have played a role in protection design this has brought extra costs but has resulted in improved safety and reliability.

2.2 SECONDARY SYSTEMS

2.2.1 Protection Relays

The overall performance of our protection relays has been satisfactory. There have been relatively few mal-operations in the last 12 months. A record of each failure is kept as an aid for tracking common failure modes.

The electro-mechanical relays have performed satisfactorily in the last 12 months. However, since these relays are not monitored in real time, any issues that arise are usually found during the maintenance rounds or by the operation of the upstream protection. (Note: the failure to trip is typically due to issues with the circuit breaker or communication cable routes)

Some of the early analogue electronic devices installed have now been identified as being problematic due to nuisance tripping, failure of discrete electronic components and difficulty sourcing spare parts. This has resulted in the phasing out of types with known failure modes. This work is often coordinated with plant replacement or major works.

Solkor relays used for unit protection account for approximately 15% of the protection relay population. While over half of them are over 20 years old, they are still supported by the manufacturer and have proven to be very robust and reliable.

Figure 3: Relay failures between 31 March 2011 and 1 April 2012

Relay Type	Location	Description
T60	Sockburn T3	Power supply failure
T60	Lincoln T1	Brick A to D converter failed
L90	Islington 2072	CPU failure
F35	QEII RMU	CPU failure
PQM II	Bromley	Non-volatile memory failure

*This list only includes in-service faults. It does not include faults due to natural events or failure found during pre-commissioning tests.

Figure 4: Problematic Relays Being Monitored

Relay Code	Average Age	No. in Network	Type	Description
BD	37	23	M	Intertrip relay (Receive)
AT	33	15	M	Reyrolle Intertrip (send)
CF11	42	5	M	Reyrolle Intertrip Rx
CAG 12	37	2	M	GEC earth fault relay - min setting too high
CDG 12	38	12	M	GEC earth fault relay - min setting too high
TEC	29	7	M	Reyrolle Intertrip Signal
RADSB 4	25	2	E	Early ASEA Tran Diff
RADHL 4	27	29	M	AESA Pilot wire – Not supported by Manufacturer
RADHD	27	3	M	AESA Pilot wire – Not supported by Manufacturer
RACID E/L	25	24	E	3ph EF(DefT) - Early ASEA
DTH31	32	6	E	Transformer Differential - problematic relay

2.3 PRIMARY EQUIPMENT

2.3.1 General

The accuracy on a small number of our CTs and VTs is outside our present standards and some early electronic relays are becoming problematic due to nuisance tripping and the failure of individual electronic components. There is a programme in place to phase out and upgrade these systems. The overall performance of our protection systems is satisfactory and major incidents are avoided with ongoing monitoring and maintenance.

Some VTs have been damaged due to lightning strikes however the incident rate is low and we do not anticipate having to install additional protection (surge arrestors) to mitigate the issue.

A programme is in place to install open delta 11kV VTs in substations with GFNs.

3 ASSET CONDITION

3.1 GENERAL

Our protection system plays an integral part in the provision of a safe and reliable network. As a result it is imperative that it is maintained in good condition.

3.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our protection relays. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual relay. This effectively gives the asset a ranking which is used when determining the replacement strategy. Note, while the model calculates the protection relay ranking it is still up to the engineer to prioritise the replacement schedule.

Creating a CBRM model for protection relays is a world first for EA Technology. Orion's knowledge of these assets and good relay data made it possible to build a model that gives an accurate reflection of its relay population.

Prior to the introduction of the CBRM model all of our protection systems were reviewed against a number of performance criteria – failure rates, post-event diagnostic capability, manufacturer support, network suitability and age. A ranking system was created to help identify any relay types that may cause us issues. These criteria are now embedded in the data used in the CBRM model and we can now calculate a health index for individual relays rather that a generic score relay types.

Figure 5: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 6: Year 0 Health Index Profile

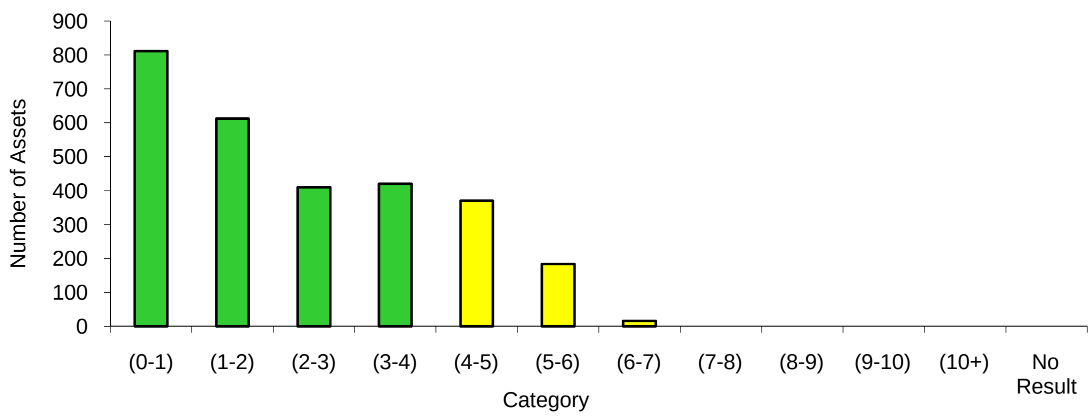


Figure 7: Year 10 Health Index Profile

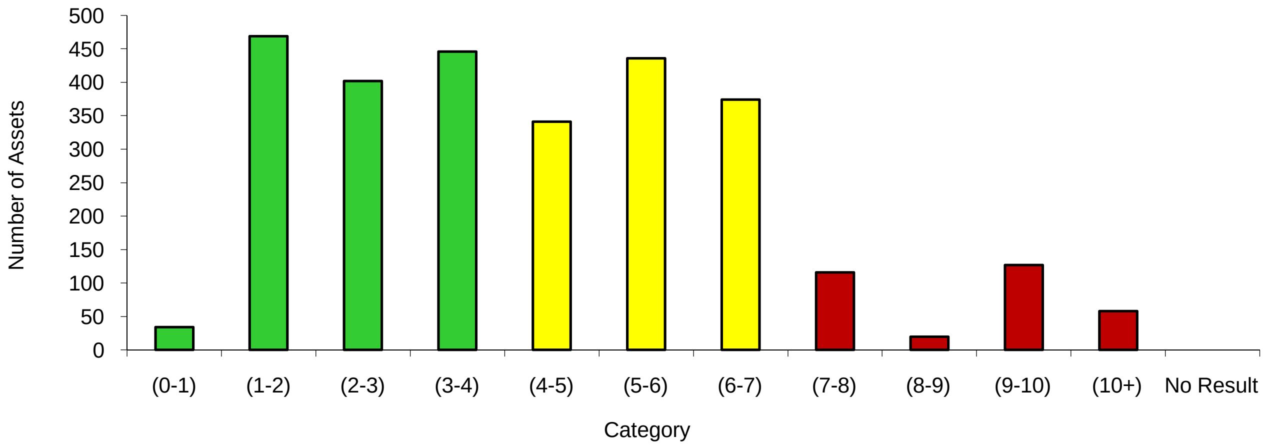


Figure 6 shows the current condition of our relay population. Figure 7 shows the condition of our relay population in 10 years time if no further investment is made in the replacement programme.

Figure 8: Year 10 - % Replacement Health Index Profile

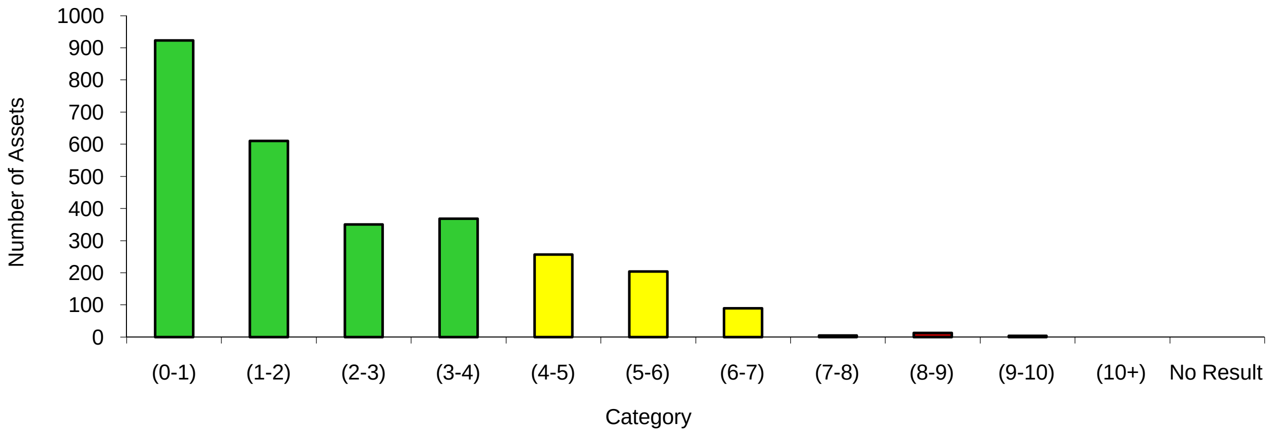


Figure 8 illustrates the year 10 condition profile if a replacement rate of 4.5% is adopted. This rate enables us to maintain our current profile. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

However the year 0 plot shows the overall condition of our protection systems is very good and we are on target with our replacement programme.

4 ASSET MANAGEMENT PRACTICES

4.1 GENERAL

We employ a number of different asset management practices to ensure we maintain a high level of reliability and performance from our protection systems.

4.2 PROTECTION SYSTEMS LIFECYCLE

4.2.1 Relays

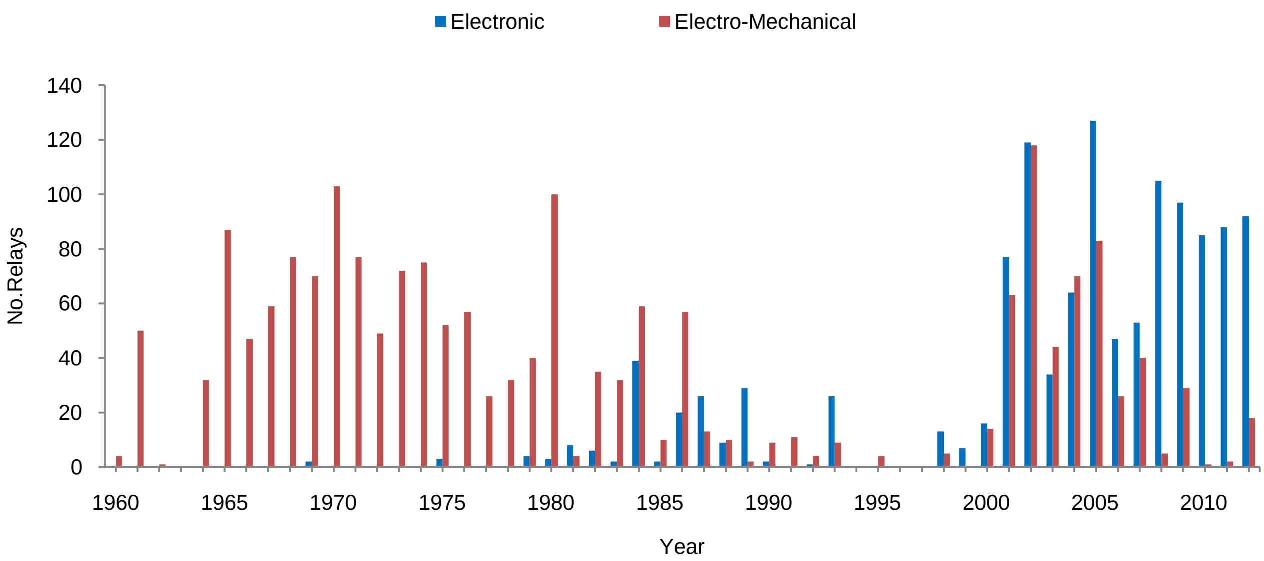
Each of our protection relay classes has a different lifecycle. Experience has shown that we can expect a nominal life of 50 years from our electromechanical relays. While it's conceivable that many of these relays can offer more than 50+ years of service, other factors such as functionality and sensitivity make it necessary to upgrade to a modern equivalent.

Some of the analogue electronic relays have been identified as problematic due to the failure of discrete electronic components. This has lead to a nominal lifecycle of only 20 years. The newer digital electronic relays are microprocessor based and while they offer far more functionality than their earlier counterparts, they have an expected lifecycle in the order of 15 – 20 years.

Figure 9: Relay Average Age

Relay Type	Average Age	Nominal Life
Electromechanical	30 yrs	50 yrs
Analogue Electronic	25 yrs	20 yrs
Digital Electronic	6 yrs	15 yrs

Figure 10: Age Profile Protection Relays



The effect of these different lifecycles means our replacement plan for protection relays will ramp up from its current level. Refer to section 6.2 Replacement Expenditure for our budgeted replacement costs.

4.2.2 Primary Plant

While the lifecycle of the CTs and VTs is linked to the substation switchgear (50+ years) there are cases where they have to be replaced to match the requirements of the protection relay.

4.3 CREATION/ACQUISITION PLAN

We have developed a programme to install a GFN at each of our rural zone substations. This programme is due to conclude in 2014. The replacement plan and upcoming major projects determine the acquisition plan for our protection systems.

4.4 MAINTENANCE PLAN

At present our protection systems are tested and maintained as part of our substation maintenance and inspection regime as detailed in Orion's Technical Specifications:

- *NW72.23.07* – Orion zone substation maintenance
- *NW72.23.06* – Orion network substation maintenance
- *NW72.27.01* – Orion 11kV unit protection maintenance tests
- *NW72.27.04* – Testing and Commissioning of Secondary Equipment.

The protection systems are checked for calibration and operation during the substation maintenance rounds and results are recorded and minor adjustments made if necessary. Major faults result in the system being removed from service and overhauled.

Figure 11 show the frequency of our maintenance and inspection rounds.

Figure 11: Switchgear/Relay Inspection and Maintenance Schedule

Location	Inspection frequency (months)	Maintenance/testing frequency (years)
Zone substation	2	4
Network substation	6	8
Distribution substation	6	8
Line circuit breakers and sectionalisers	12	8
Unit protection		4

4.5 REPLACEMENT PLAN

Traditionally the protection replacement programme has been directly linked to the replacement of switchgear. Usually both asset groups were installed at the same time and had similar lifecycles. On some occasions a protection system will be upgraded due to the performance requirements of the network. With the introduction of the electronic relays (both analogue and digital) synchronisation of the lifecycles with switchgear has been lost.

Protection systems with known performance issues are given a higher priority for replacement. Prior to the CBRM model being available we relied on the ranking system we developed in 2009.

This year we used a combination of both of the asset ranking systems and other factors such as the upgrading/replacement of substation primary equipment or changes in the requirements of the local network to develop the protection relay replacement programme.

We will refine this process on an annual basis as we move from a primarily time base replacement programme to one based on condition assessment and risk analysis.

4.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

4.7 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

4.8 RISK ANALYSIS

We undertake a risk analysis assessment on an ongoing basis to ensure protection schemes meet the current standards. Public and personnel safety is our highest priority.

We hold a number of spare relays to ensure we have sufficient cover for any failures. There is no formal process around determining the level of spares we should hold and we have identified this as a gap in our asset management practices. A project to formalise this process will be undertaken in the near future.

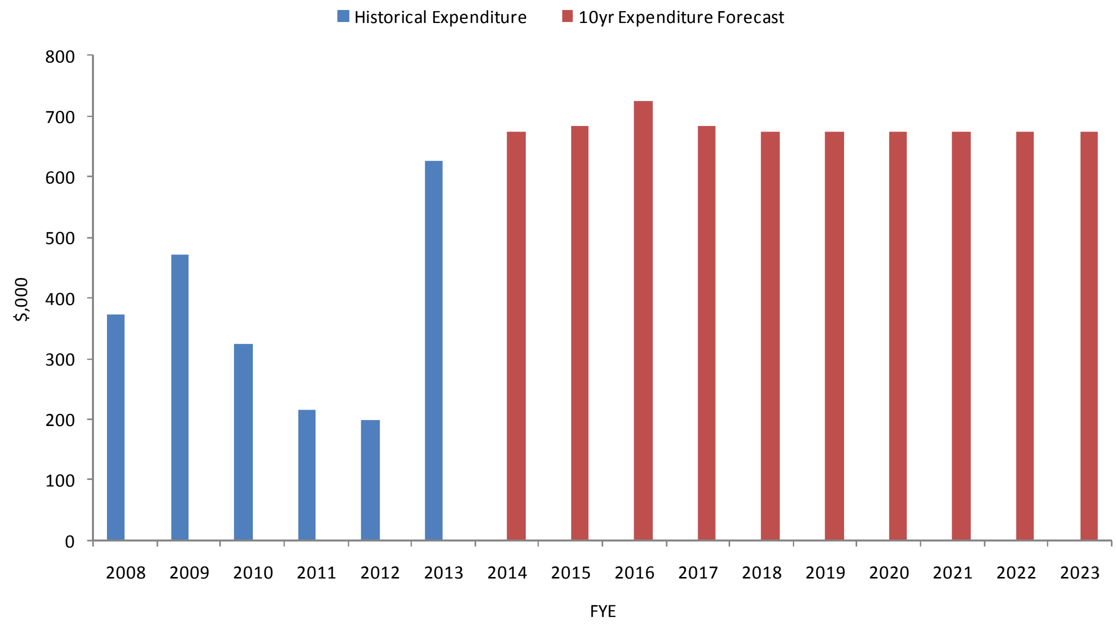
Refer to Appendix A for a list of our spare relays.

5 EXPENDITURE

5.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 12: Protection Systems Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 13: Protection Systems Historical Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	159	254	129	55	67	385
Non-Scheduled	77	132	109	74	32	110
Emergency	138	85	86	87	101	130
Total	**374**	**471**	**324**	**216**	**200**	**625**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

We have noticed with the increased complexity of protection systems, driven by customer expectations for reliable supply, that it is becoming difficult to obtain outages. This was the case in 2010. The purchase of the spur assets gives us more flexibility as we no longer have to try and co-ordinate our outages with Transpower at Papanui. The availability of outages is sporadic in nature, therefore higher cost are incurred.

Figure 14: Protection Systems Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	390	400	400	400	390	390	390	390	390	390
Non-Scheduled	110	110	110	110	110	110	110	110	110	110
Emergency	175	175	215	175	175	175	175	175	175	175
Total	**675**	**685**	**725**	**685**	**675**	**675**	**675**	**675**	**675**	**675**

Our scheduled maintenance for protection systems is carried out as part of the wider substation maintenance programme. These works are tendered out as part of our contracting model. There has been an increase in budget as we prepare to acquire equipment as part of the spur asset transfer from Transpower.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

5.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 15: Historical and Forecast Expenditure

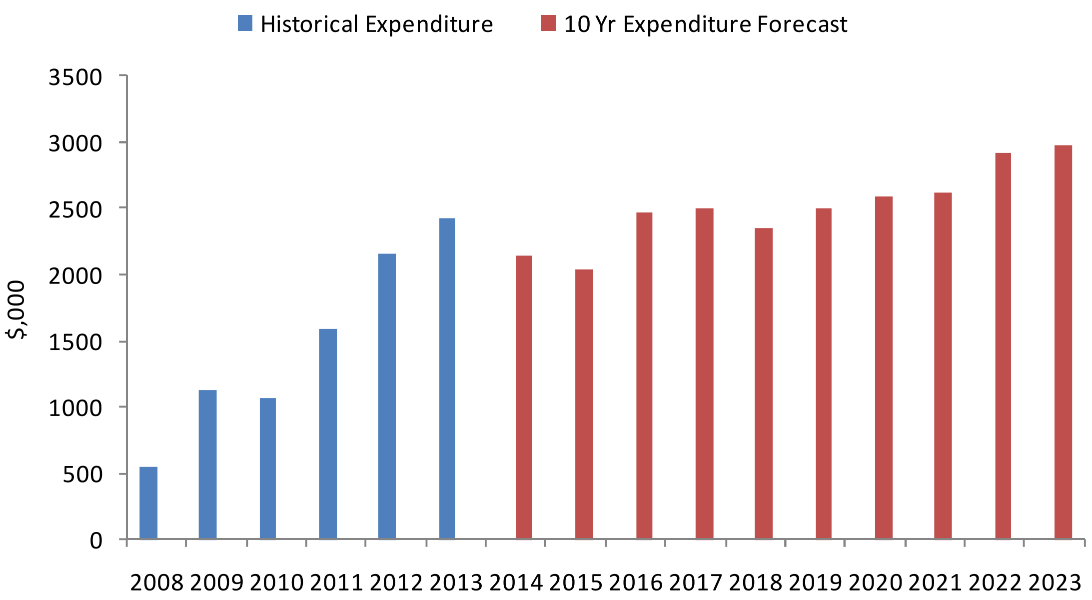


Figure 16: Protection Systems Historical Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	544	1121	943	1586	2145	2135
Spur Assets	-	-	-	-	-	295
Total	**544**	**1121**	**943**	**1586**	**2145**	**2430**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used. The trend shows that our replacement programme is ramping up as our electromechanical relays and analogue digital relays near the end of their lifecycles.

Figure 17: Protection Systems Replacement Expenditure Forecast ($,000)

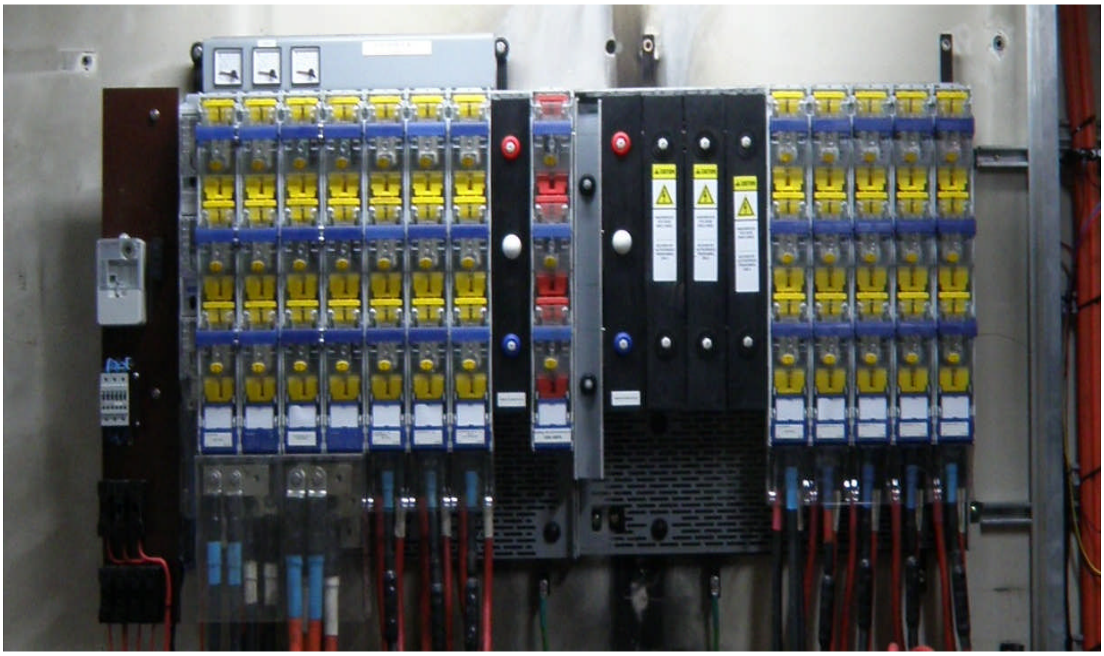
FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	1907	1794	2228	2261	2354	2493	2592	2622	2917	2972
Spur Assets	235	240	235	235	-	-	-	-	-	-
Total	**2142**	**2034**	**2463**	**2496**	**2354**	**2493**	**2592**	**2622**	**2917**	**2972**

Appendix A

Manuf	PN	Type	Location	MFG Date	Firmware	Serial #	Comments	Status
GE	B90	B90 G02 HCH F6G H6C W7H	Stock	Nov 01 2006	Ver 4.90	AA6C06000356		Available
GE	C30	C30-N00-HKH-G6N	Stock	Jul 10 2008	Ver 5.50	AA7C08000209		Available
GE	F35	F35-N00-VCH-F8L-H6N	Stock	Aug 15 2007	Ver 5.40	AA1C07000728		Available
GE	F35	F35-G00-HCH-F8F-H6G	Stock	Jul 13 2006	Ver 5.00	AAFC06000463		Available
GE	F35	F35-G00-HCH-F8F-H6B-M8H-P6B-U8H	Stock	Jul 11 2006	Ver 5.00	AAFC06000464		Available
GE	F35	F35-G00-HCH-H6G	Stock	Aug 31 2006	Ver 5.00	AAFC06000603		Available
GE	F35	F35-N00-HKH-F8L-H6N-U6N	Stock	Aug 31 2011	Ver 5.90	AAIC11001329		Available
GE	F60	F60-N00-HKH-H81	Stock	Jun 23 2009	Ver 5.00	MAHC09000064		Available
GE	F60	F60-G00-HCH-F8F-H6G	Stock	Aug 31 2006	Ver 5.00	AAHC06000823		Available
GE	G30	G30-N00-HLL-F8L-H6N-M8L-P6N	Stock	Dec 19 2011	Ver 6.00	AAKC11000174		Available
GE	L90	L90-C00-HCH-F8A-H6H	Stock	May 17 2004	Ver 3.4x	AAZC04000283		Available
GE	T60	T60-G00-HCH-F8H-H6H-M8F-P6E-UGA	Stock					Available
GE	T60	T60-C00-HCH-F8C-H6H-M6D	Stock	Jan 20 2003	Ver 3.11	ABHC03000023		Available

HV and LV Switchgear

Asset Management Report YE 2012



NW70.00.24

Table of Contents

1 INTRODUCTION

This document covers each of our high voltage (HV) and low voltage (LV) switchgear categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these switches.

2 ASSET DESCRIPTION

2.1 GENERAL

2.1.1 Magnefix Switch Unit (MSU)

These switches are an independent manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. Each phase is switched separately or three phases are operated simultaneously with a three phase bridge. These switches are the predominant type installed in our 11kV cable distribution network. They are mainly installed in distribution kiosks and as secondary switchgear in network substations. They range in configuration from a two cable unit to a five cable unit, making a total of over 10,000 individual outlets in our network.

2.1.2 Xiria Ring-main Unit

These units are arc-contained, fully enclosed metal-clad 11kV switchgear. They combine both load-break switches and vacuum circuit breakers. With the addition of electronic protection relays they can be fully automated. They are usually installed in kiosks or as secondary switchgear in zone and network substations. They are available as three or four panel units.

2.1.3 Oil switch, fused and non-fused

These switches were installed in our 11kV cable distribution network as secondary switchgear in network and distribution building substations. They were installed before low maintenance oil-free MSUs were proven. We no longer install these switches.

Some of the installations have locally designed bus connections that are below our current standards. Incidents and difficulties in arranging outages to carry out servicing have occurred, therefore we are gradually replacing these switches with MSUs.

2.1.4 Air break isolator (ABI)

11kV and 33kV line ABIs are pole mounted in our rural overhead network. All new 11kV ABIs installed since 2007 do not have operating handles and are instead operated by a hot-stick. This makes them more secure and removes the need for earthing.

The substation 66kV and 33kV ABIs are used as isolation points in the substation structures and are mounted on support posts or hang from an overhead gantry.

A few 11kV ABIs in remote areas have been automated by installing a power-actuator to allow remote operation for fault clearing. This speeds up the isolation of the faulty sections of the network.

2.1.5 Sectionaliser

11kV sectionalisers are pole mounted, oil filled and installed to perform a similar function to the remotely controlled ABIs. The operation is automated, with the sectionaliser opening after detecting a pre-set number of unsuccessful attempts to re-liven by an upstream circuit breaker.

Sectionalisers are not remotely monitored.

2.1.6 Low voltage switch

Installed generally in distribution substations, these switches form the primary connection between 11kV/400V transformers and the 400V distribution network, giving isolation points and fusing capability using high rupturing current (HRC) links. All new installations are of the DIN type.

The majority of existing older panels (approximately 3,000) are a British exposed-bus (skeleton) and V-type fuse design. As accidental contact is a risk with these designs, we have a programme underway to replace them with the modern DIN type.

2.2 ASSET TYPES

Figure 1: Asset Types

Asset Types	Total No.	Avg Age (yrs)
MSU	3,874	23
Xiria Ring-main	19	3
Oil / Fuse Switch	159	40
11kV ABI	971	20
33kV ABI	90	20
66kV ABI	88	19
Sectionaliser	4	27

3 ASSET PERFORMANCE

3.1 GENERAL

3.1.1 Magnefix Switch Unit (MSU)

An MSU is a manually operated quick-make, quick-break switch design rated at 400A. Failures are usually due to secondary factors such as a cable termination failure.

3.1.2 Xiria Ring-main Unit

These units combine both load-break switches (rated at 630A) and vacuum CBs (rating depends on cones installed, 400A with C type and 200A with A type cones fitted). Any failures in these units are usually due to secondary factors such as cable terminations.

3.1.3 Oil switch

Oil switches are manually operated. They have caused some problems over the years due to oil leaks and jammed operating mechanisms.

3.1.4 Air break isolator (ABI)

A standard existing ABI installed on our rural network (33kV and 11kV) is rated at 400A. Load-break attachments have been installed on a number of isolators in key locations to increase the current rating to 600A. All new ABIs are 600A and hot-stick operated with load-break.

The substation ABIs are unable to break circuit load current.

The performance of our ABIs is generally good, although isolators that have not operated for a long time have a tendency to seize up. Loose terminations and contacts can also cause problems on older ABIs.

3.1.5 Sectionaliser

Sectionalisers installed on the network are rated at 200A continuous, 9kA fault. As they age, they can become unreliable in their operation.

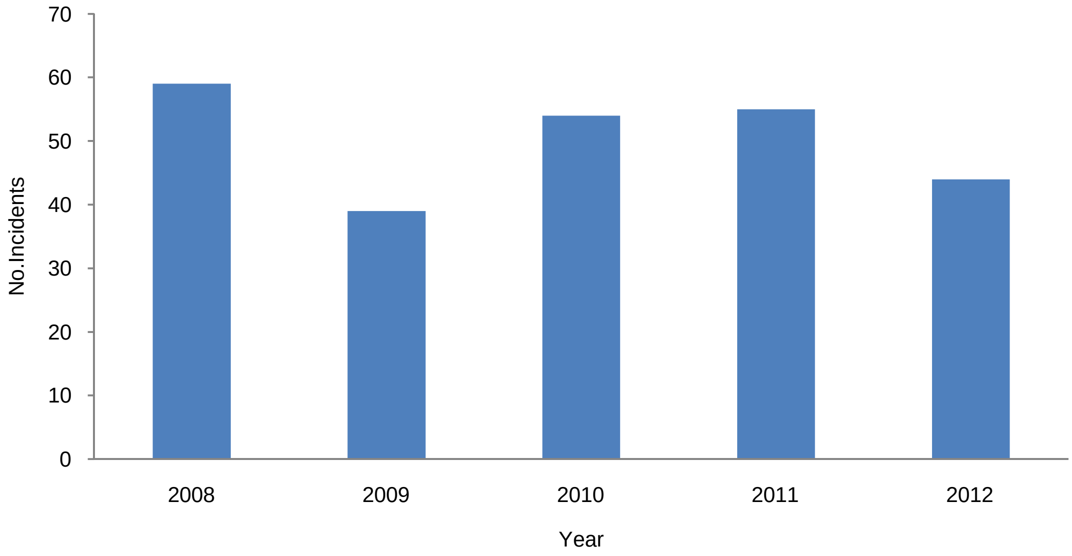
3.1.6 Low voltage switch

The standard rating of the low voltage DIN switches is 630A, with panel busbar ratings of 800A or 1500A installed to meet distribution substation and feeder capacities.

The ‘skeleton’ type panels and switches have good electrical performance; however, the exposed busbars are a safety issue.

Some issues have surfaced with DIN type switches. These have generally related to overheating created by the quality of connection and installation. Overheating is a more significant issue for DIN switches than for other switches, due to their enclosed construction.

Figure 2: HV and LV Switchgear Performance



The number of faults/incidents is relatively low given the size of our switchgear population.

4 ASSET CONDITION

4.1 GENERAL

4.1.1 Magnefix Switch Unit (MSU)

The condition of MSUs within the network is very good.

4.1.2 Xiria Ring-main Unit

The condition of the RMUs is very good.

4.1.3 Oil switch

Oil switches are maintained in good operational condition. Any problematic units can be decommissioned and replaced with a ring main unit.

4.1.4 Air break isolator (ABI)

The condition of our line ABIs on the network is generally good. However, the older Canterbury Engineering types are reaching the end of their economic life.

4.1.5 Sectionaliser

The condition of some sectionalisers is deteriorating, and a detailed assessment is being carried out on all units. A few have reached the point where replacement is the most economic option.

4.1.6 Low voltage switch

The low voltage panels and switches are generally in good condition.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our HV and LV switchgear. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual unit. This effectively gives the asset a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Figure 3: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 4: Year 0 Health Index Profile – HV and LV Switchgear

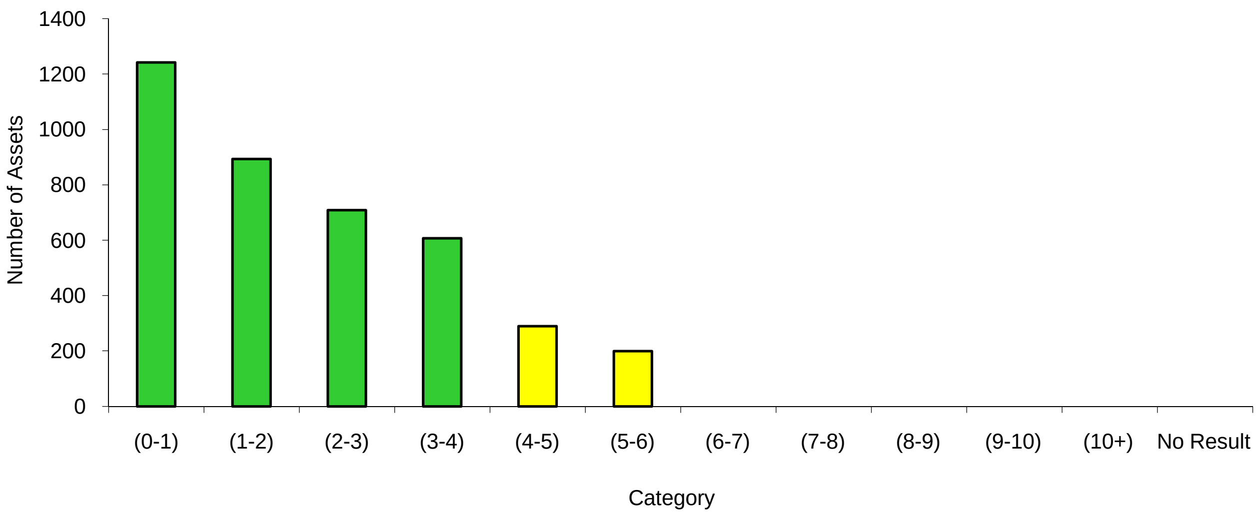


Figure 5: Year 10 Health Index Profile – HV and LV Switchgear

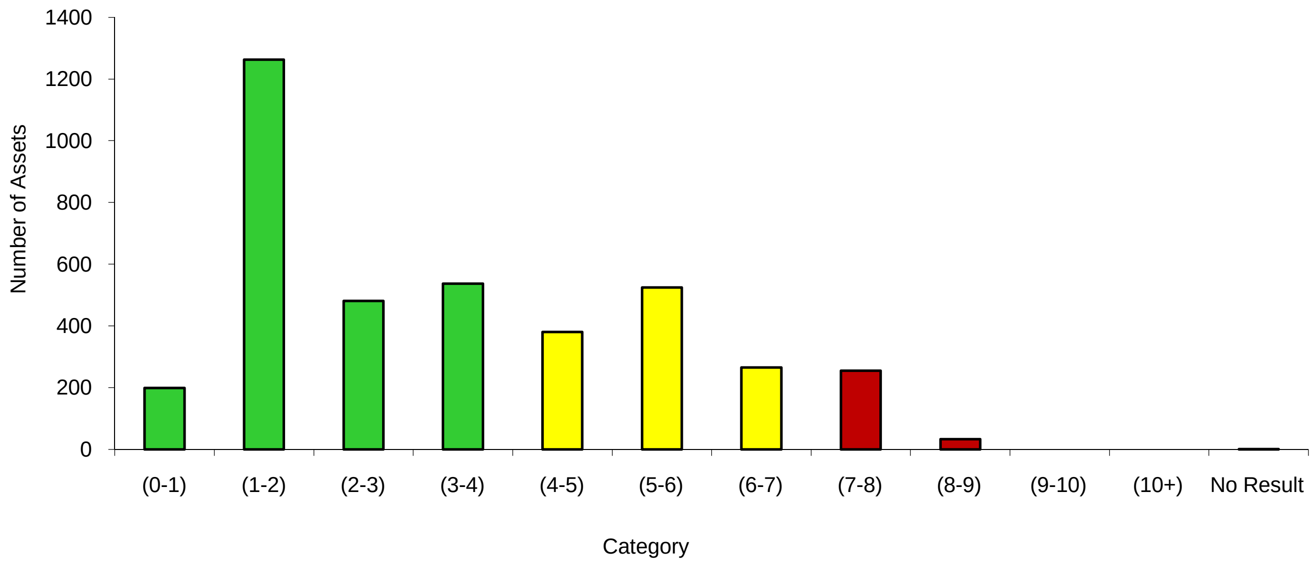


Figure 4 shows the current condition of our HV and LV switchgear. Figure 5 shows the condition of our HV and LV switchgear in 10 years time if no further investment is made in the replacement programme.

Figure 6: Year 10 – % Replacement Health Index Profile – HV and LV Switchgear

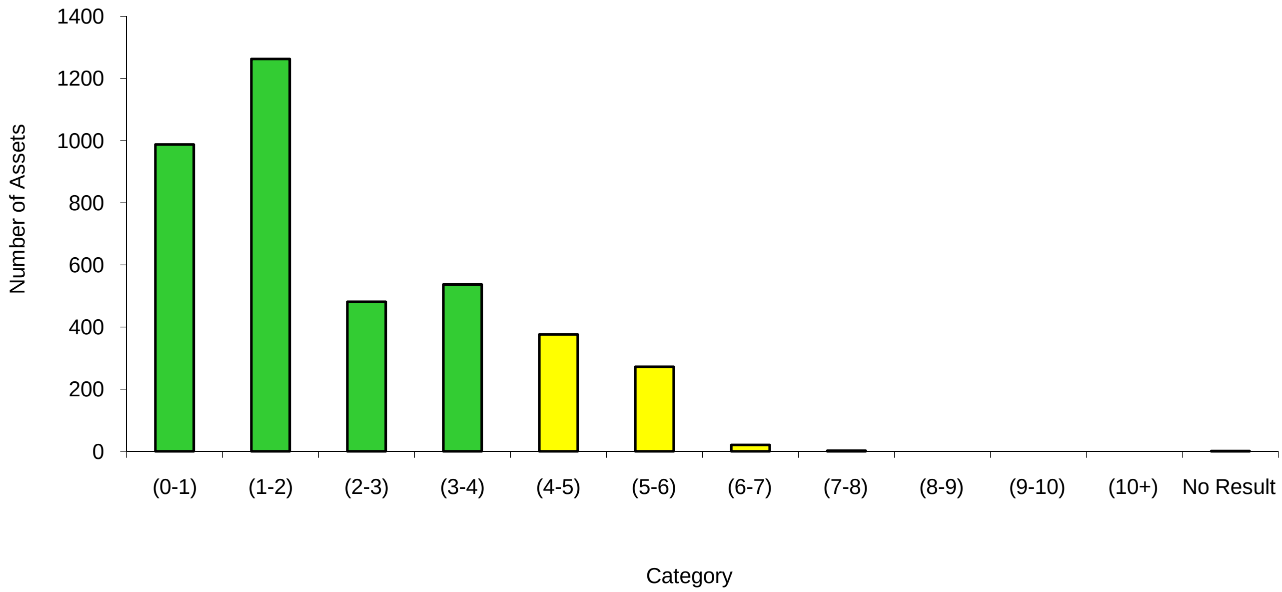


Figure 6 illustrates the year 10 condition profile if a replacement rate of 2.0% is adopted. This rate enables us to maintain our current profile. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

However the year 0 plot shows the overall condition of our HV and LV switchgear is good and we are on target with our replacement programme.

Figure 7: Year 0 Health Index Profile – Air Break Isolators

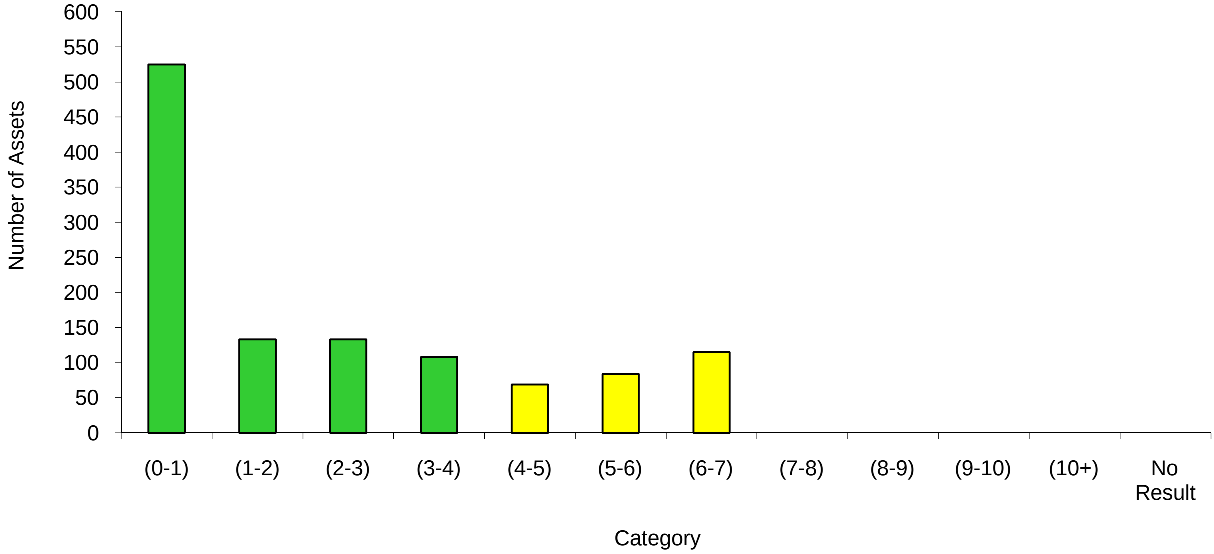


Figure 8: Year 10 Health Index Profile – Air Break Isolators

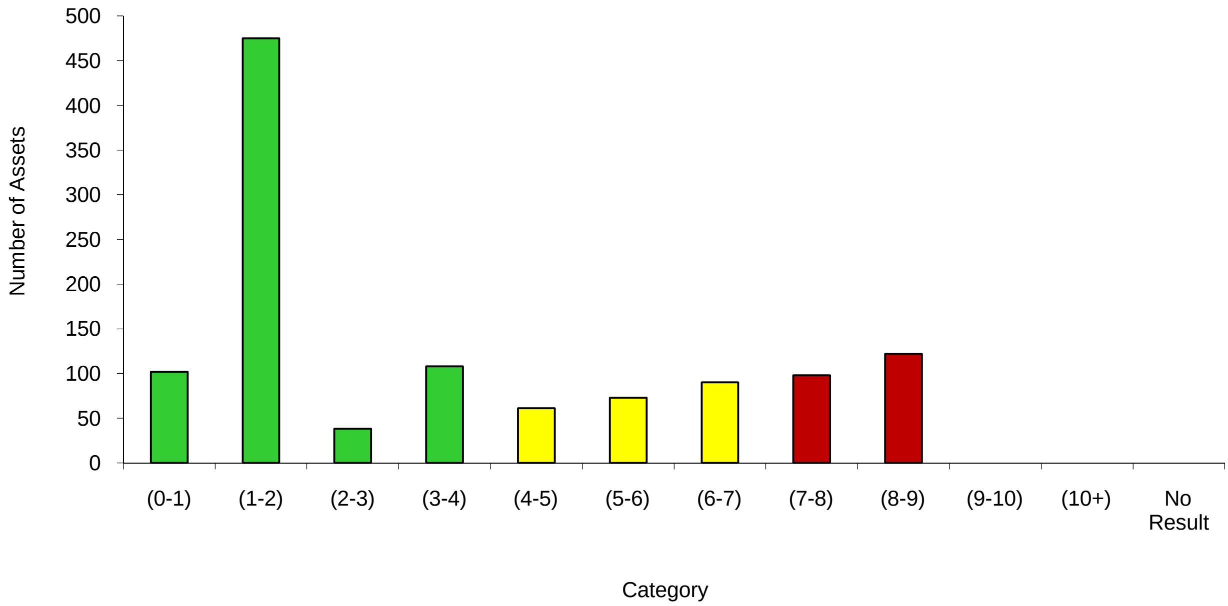


Figure 7 shows the current condition of our HV and LV switchgear. Figure 8 shows the condition of our HV and LV switchgear in 10 years time if no further investment is made in the replacement programme.

Figure 9: Year 10 – % Replacement Health Index Profile – Air Break Isolators

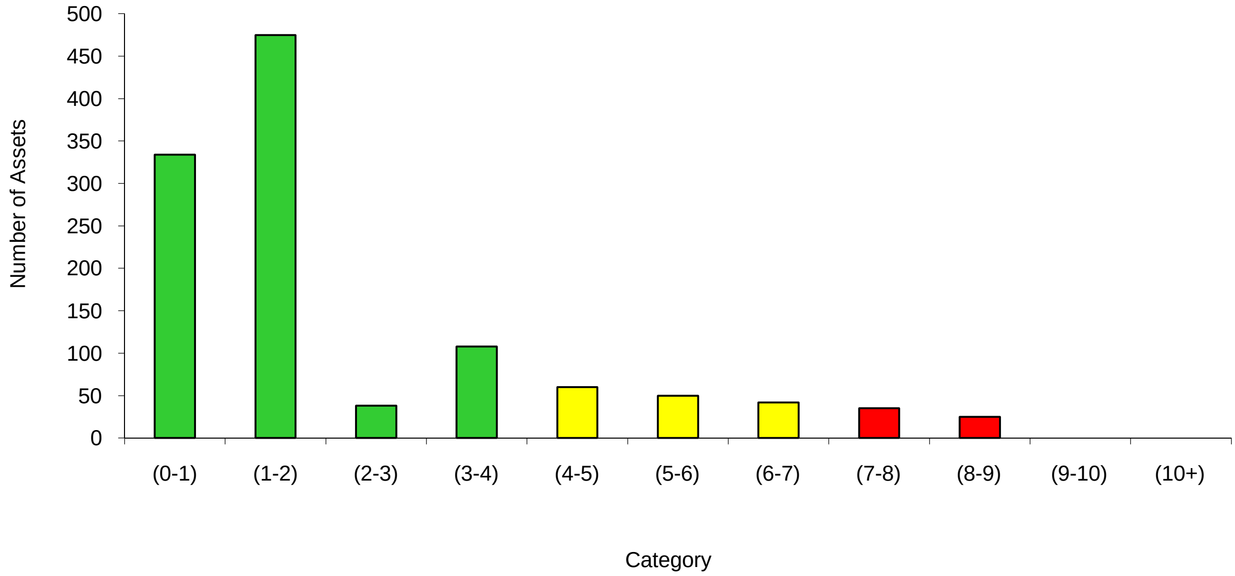


Figure 9 illustrates the year 10 condition profile if a replacement rate of 2.0% is adopted. This rate enables us to maintain our current profile. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

However the year 0 plot shows the overall condition of our air break isolators is acceptable and we are on target with our replacement programme.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

We employ a number of different asset management practices for different asset groups. Generally these assets are maintained and inspected as part of our overall substation maintenance and maximum demand indication (MDI) rounds.

5.2 HV AND LV SWITCHGEAR LIFECYCLE

Figure 10: Age Profile MSU and Xiria

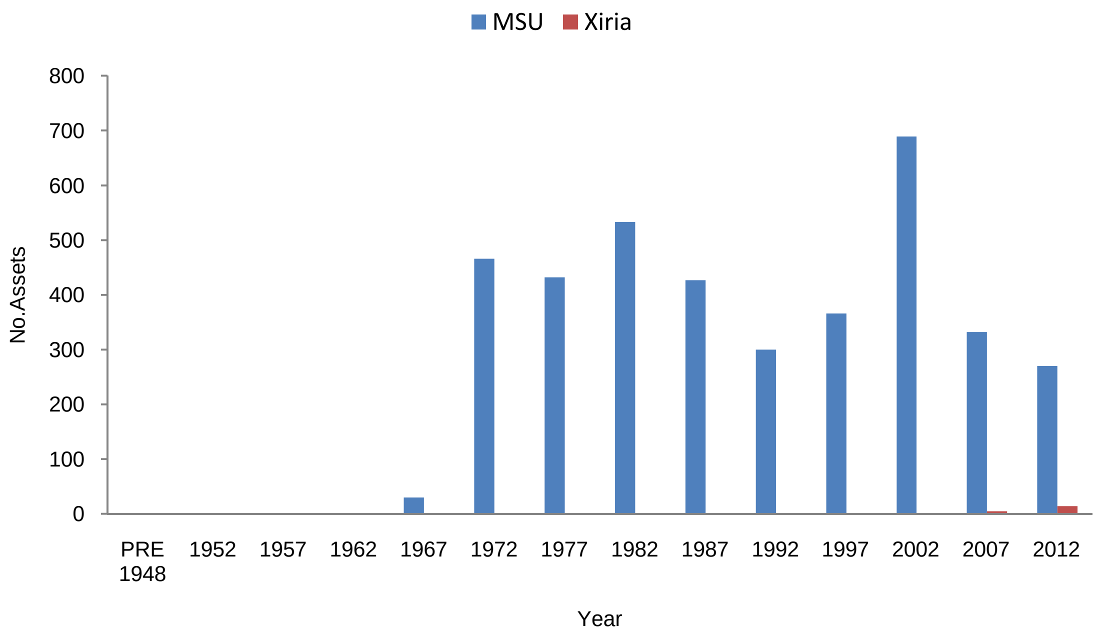


Figure 11: Age Profile MSUs

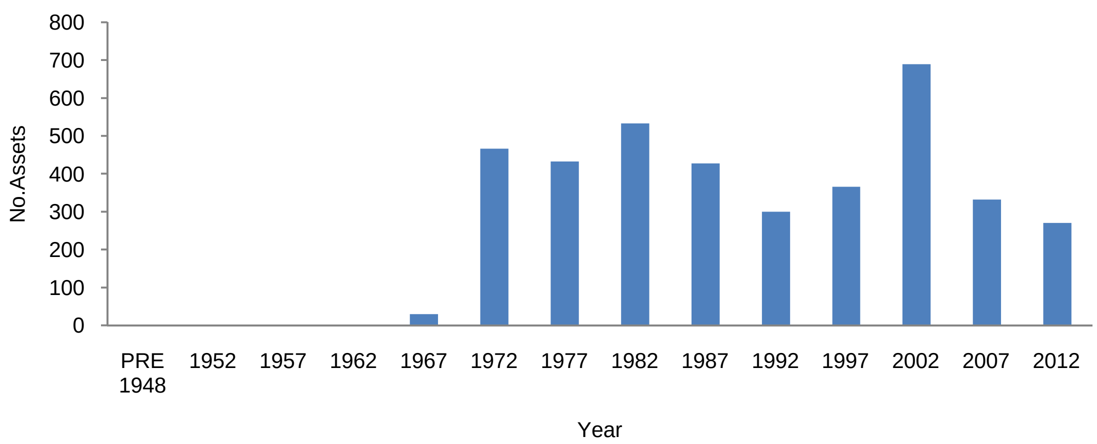


Figure 12: Age Profile Xiria

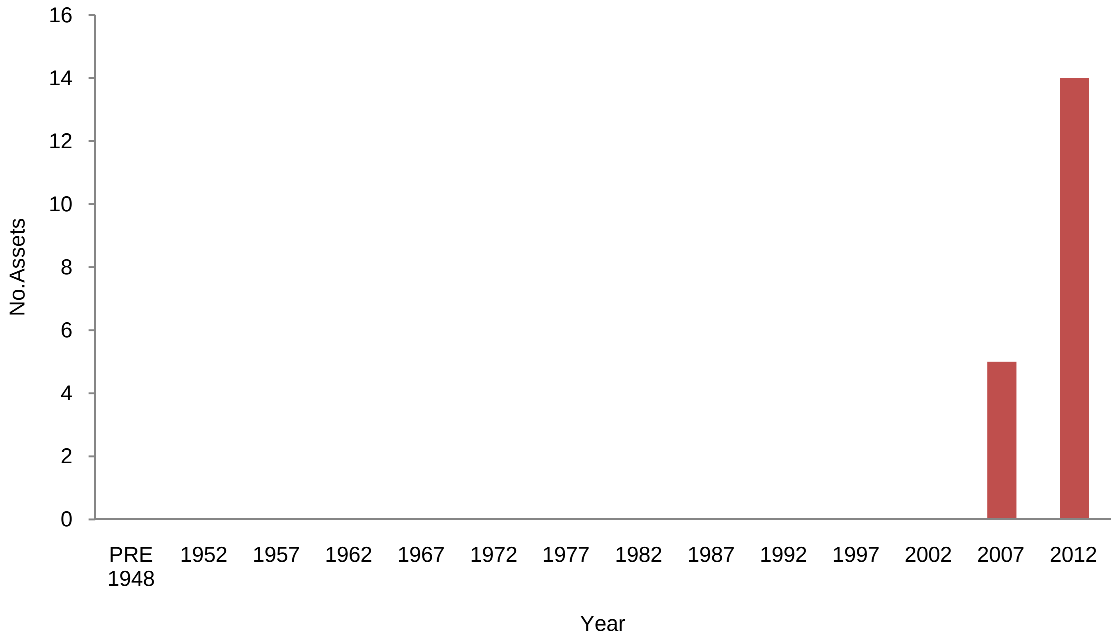


Figure 13: Age Profile 11kV Air Break Isolators

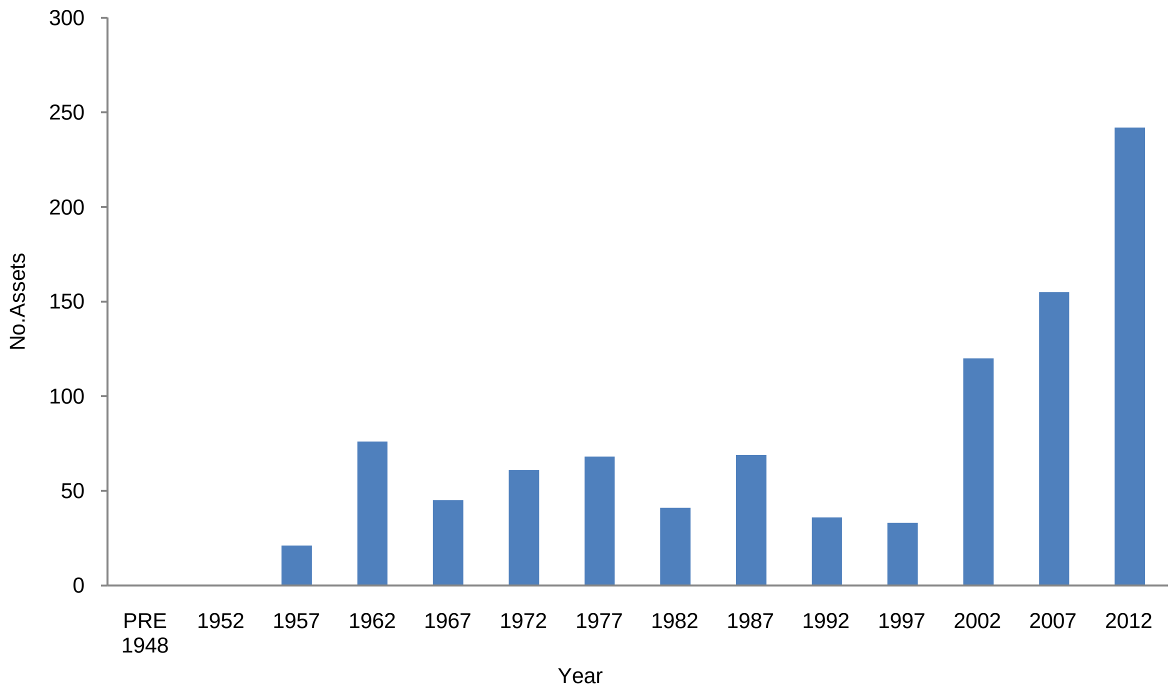


Figure 14: Age Profile Oil / Fuse Switches

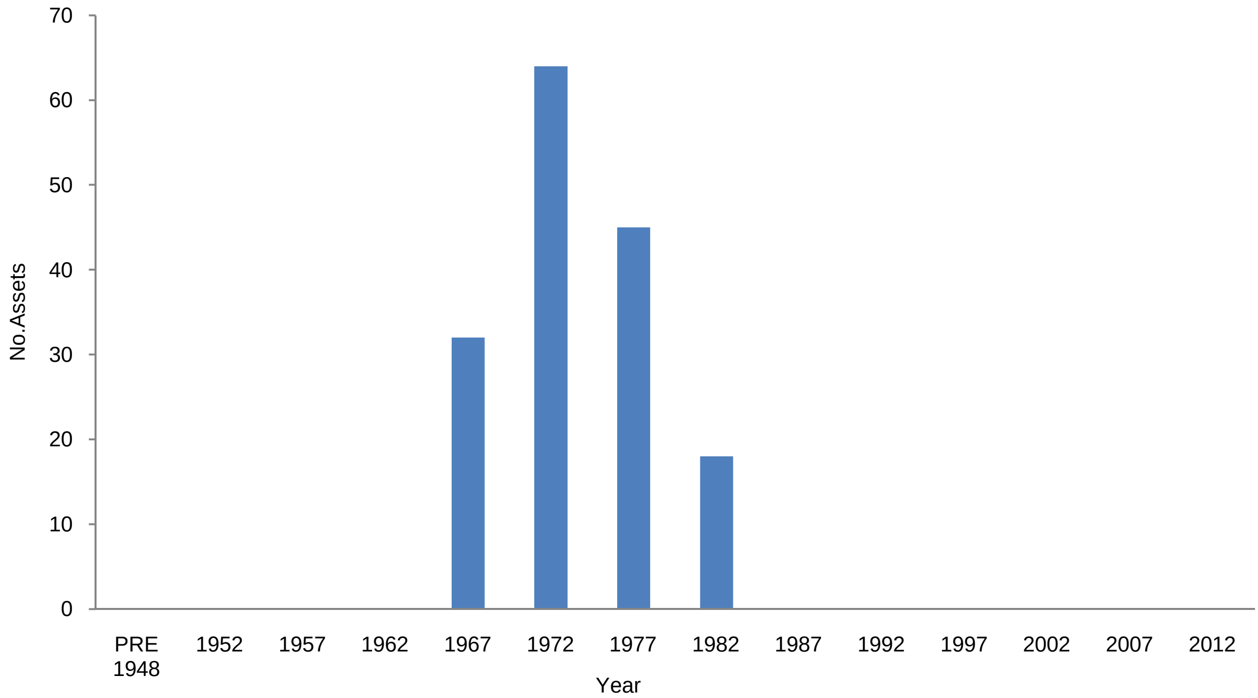
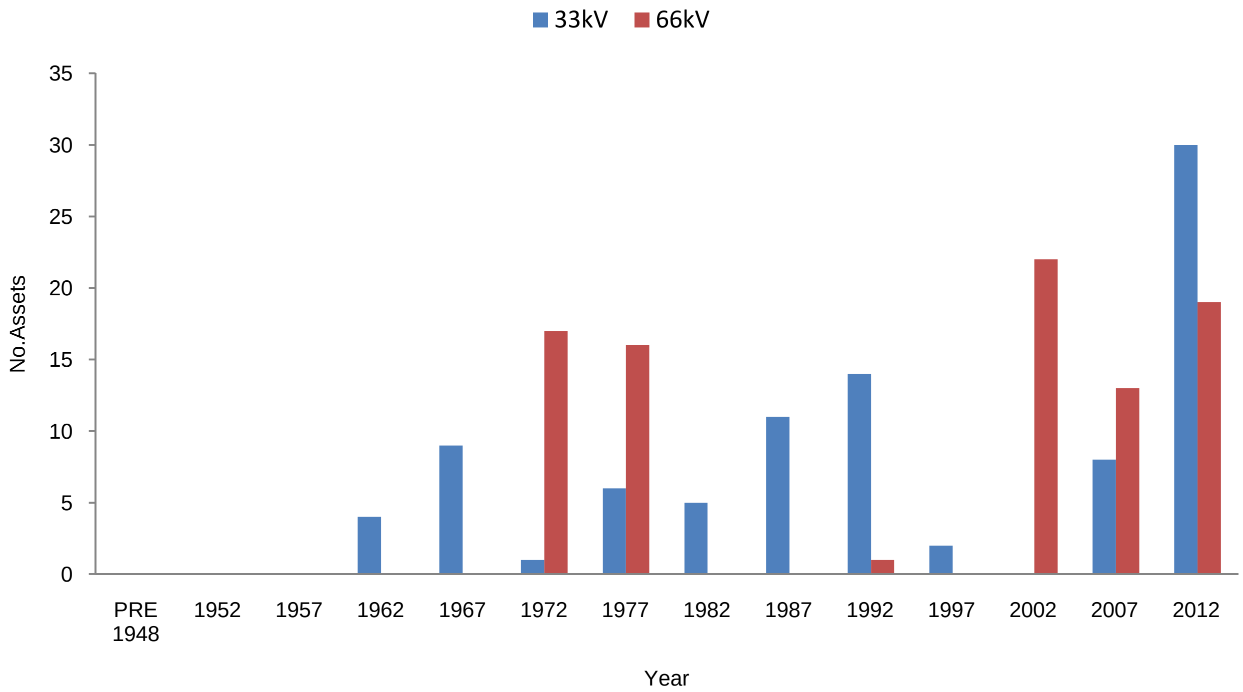


Figure 15: Age Profile 33 and 66kV Air Break Isolators



5.3 MAINTENANCE PLAN

5.3.1 Magnefix Switch Unit (MSU)

11kV MSUs are virtually maintenance free, with the exception of minor dusting from time-to-time. The exceptions are those units in close proximity to the sea. They are maintained every four years.

5.3.2 Xiria Ring-main Unit

Ring-main units in indoor situations are maintained as part of the programme of work (four or eight yearly) for the substation in which they are installed.

5.3.3 Oil switch

Oil switches in indoor situations are maintained as part of the programme of work (four or eight yearly) for the substation in which they are installed.

5.3.4 Air break isolator (ABI)

A check on the operation of standard ABIs is included when a line retighten contract is carried out each year. Other maintenance work is on an as-required basis.

5.3.5 Sectionaliser

Sectionalisers are maintained every eight years, with an annual external inspection.

5.3.6 Low voltage switchgear

Substation low voltage panels are inspected every six months. Other switches are inspected on a five yearly basis. We are just over halfway through a four-year programme to install safety barriers over the open and live busbars and switches.

5.4 REPLACEMENT PLAN

Traditionally the replacement plan was driven by the age of the switchgear or any issues that may have arisen due to safety. This year we have used a combination of the age profile and CBRM model. Once we have refined some of our processes, the replacement plan will be based solely on the results from the CBRM model. See Appendix A for replacement plan.

5.5 DISPOSAL PLAN

These assets are disposed of as part of replacement costs.

5.6 CREATION / ACQUISITION PLAN

We plan to install additional switchgear during projects that improve the reliability of the network, and in works to satisfy consumer demand.

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability. As all works are carried out during the wider substation maintenance programme, we do not distinguish between circuit breakers and switchgear for opex.

Figure 16: Historical and Forecast Expenditure

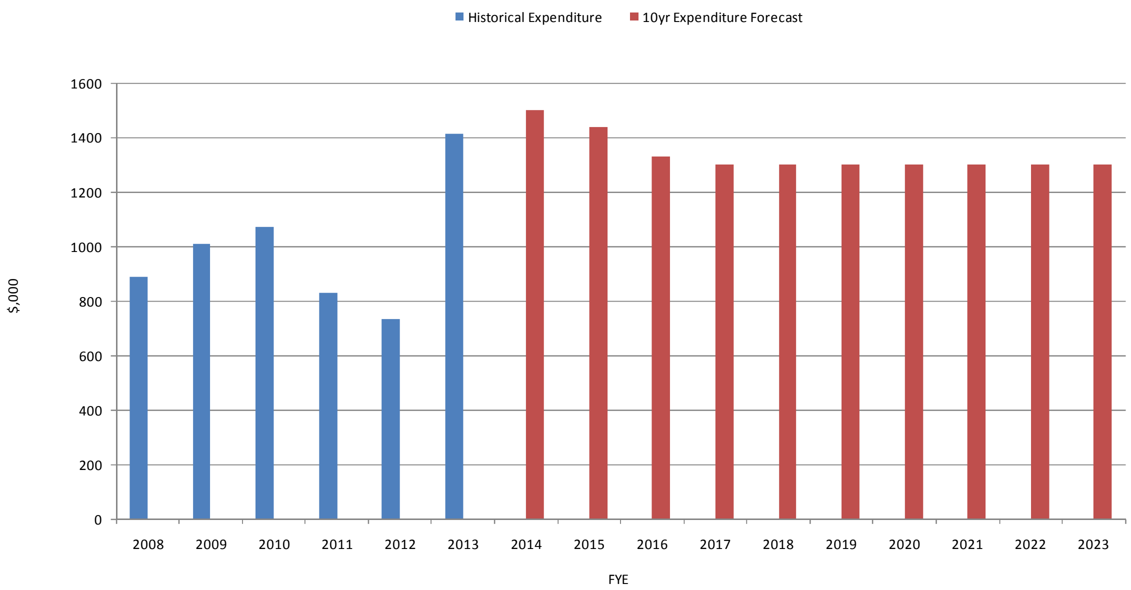


Figure 16 is a plot of our total historic and forecasted expenditure for both our circuit breakers and switchgear. We do not separate our maintenance expenditure for these assets.

The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 17: Historical HV and LV Switchgear Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	681	787	759	584	486	1177
Non-Scheduled	107	99	164	200	174	125
Emergency	100	126	151	48	74	110
Total	**888**	**1012**	**1074**	**832**	**735**	**1412**

At the time of writing, the budgeted rather than actual expenditure figures were used. In 2010, there was a spike in Opex due to the start of our protective barrier programme. During an annual financial review, it was noted that this programme should be classed as capital works rather than maintenance. Therefore from 2011 onwards the barrier programme was recorded in our capex expenditure.

Figure 18: HV and LV Switchgear Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	1225	1165	1025	1025	1025	1025	1025	1025	1025	1025
Non-Scheduled	125	125	125	125	125	125	125	125	125	125
Emergency	150	150	180	150	150	150	150	150	150	150
Total	**1500**	**1440**	**1330**	**1300**	**1300**	**1300**	**1300**	**1300**	**1300**	**1300**

Our scheduled maintenance for all switchgear (including circuit breakers) is carried out as part of the wider substation maintenance programme. These works are tendered out as part of our contracting model. There has been a slight increase in budget as we prepare to acquire equipment as part of the spur asset transfer from Transpower.

Our non-scheduled maintenance forecast is for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme. At the time of writing we were unable to separate our historical expenditure for HV/LV switchgear from CBs. For a record of total switchgear expenditure refer to section 6.2 in NW70.00.33.

Figure 19: Historical and Forecast Expenditure

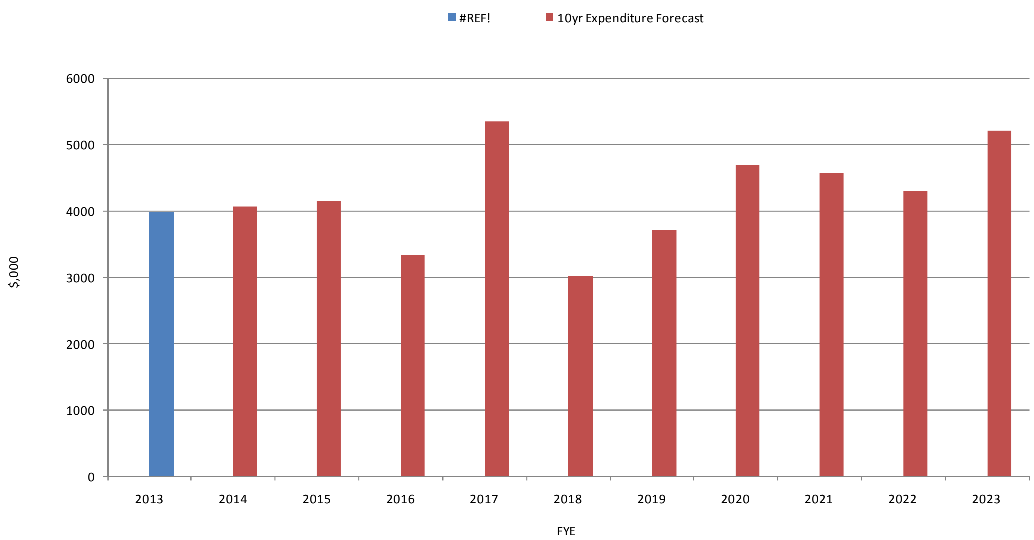


Figure 20: Historical HV and LV Switchgear Replacement Expenditure ($,000)

FYE	2013
Replacement	3984
Total	**3984**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

Figure 21: HV and LV Switchgear Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	4076	4152	3331	5351	3023	3712	4686	4568	4306	5209
Total	**4076**	**4152**	**3331**	**5351**	**3023**	**3712**	**4686**	**4568**	**4306**	**5209**

High Voltage Circuit Breakers

Asset Management Report YE 2012

NW70.00.33

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1 INTRODUCTION

High voltage circuit breakers (HV CBs) are mainly installed at network and zone substations but also in the overhead line network to provide safe interruption of both fault and load currents during power system faults. These assets can have long replacement lead times, so effective asset management practices are required.

This document covers each of our CB categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these units.

2 ASSET DESCRIPTION

A CBs primary function is to interrupt current flow in a safe manner. Our CBs are strategically placed in the network for the protection of lines, cables, power transformers and ripple plants. Different types are used throughout the network depending on the local operating voltage and current rating requirements.

Both the 66kV and 33kV CBs are used to protect the power transformers and the subtransmission network that links our zone substations.

Figure 1: Circuit Breakers

Voltage	Gas CB	Oil CB	Vacuum CB	Total
11kV	39	1192	688	1919
33kV		22	28	50
66kV	48	6		54
Total	**87**	**1220**	**716**	**2023**

2.1 66KV CIRCUIT BREAKERS

Our 66kV CBs are mainly installed outdoors at zone substations. Armagh zone substation is one exception where ‘outdoor’ CBs are installed indoors in a specially designed building. A project is currently being untaken at McFaddens zone substation to build a second indoor 66kV substation, which is due for completion in 2013. A third is to follow at Dallington zone substation in late 2013.

We have six units at Halswell zone substation that were purchased before 1974 and are a minimum oil interruption type with live tank units. The remaining 66kV CBs in the network are a mixture of live tank and dead tank units using SF_6 gas as the interruption medium.

2.2 33KV CIRCUIT BREAKERS

We have a mixture of outdoor and indoor 33kV CBs installed at our 33kV zone substations. Those installed before 2001 are mainly outdoor minimum oil interruption type. The newer units are indoor vacuum interruption type. Duvauchelle, Hornby, Motukarara, and Lincoln zone substations have recently been converted from outdoor 33kV switchgear to indoor vacuum type units. Prebbleton zone substation was purpose built in 2010 for indoor vacuum units. Moving from outdoor to indoor switchgear has the advantage of improved security and public safety.

2.3 11KV CIRCUIT BREAKERS

2.3.1 Indoor

Our indoor 11kV CBs are metal-clad and are used for the protection of primary equipment and the distribution network. The older units use oil or SF_6 as an interruption medium, while those installed after 1992 use a vacuum. 11kV CBs are used throughout the entire rural and urban networks.

2.3.2 Pole Mounted

Our overhead line CBs are pole mounted with reclose capability and are installed in rural locations to help improve feeder reliability. This is achieved by isolating a portion of the line rather than tripping the substation CB. Some CBs are equipped with UHF communication equipment to enable remote control and indication via SCADA.

3 ASSET PERFORMANCE

3.1 GENERAL

The rating requirements of a CB are determined by the system operating voltage, fault rating and the local load. As a result load current and fault current interruption capabilities can vary for CBs of a given operating voltage.

Figure 2: Circuit Breaker Ratings

Voltage	Current Rating	Fault Rating
66kV	1600A – 2500A	29kA - 31.5kA
33kV	400A – 1600A	6kA – 29kA
11kV	200A – 2500A	2kA – 26.5kA

All CBs are operated within their load ratings.

The overall performance of our CBs has been satisfactory. There have been isolated cases of failures. These units have been identified during the maintenance rounds or during an ‘emergency works’ job. The problems have been mitigated and the breakers returned to service.

Figure 3: Circuit Breaker Failures

Breaker Type	Location	Description	Action
DT09	Armagh	Lost SF_6 gas in units 112, 132 & 182	Repaired on site
LMVP	Brookside	Damaged worm drive on CB113	Replaced unit with spare and repaired in workshop
LMVP	Lancaster	Cracks in the cast resin cover on the switchgear trucks	Working with manufacturer for a solution
DT09	Heathcote	Unit 142 gear mechanism jammed causing motor to burn out	Replaced unit with spare and repaired in workshop

3.2 HISTORICAL ISSUES

3.2.1 Slow Tripping

Some of our older CBs had slow tripping times. Initially trip-assist springs were added to help improve performance; however in some cases these made little difference. Further investigation found that the tripping mechanisms were slow to trip due to the thickening of the lubricants used. Once the mechanisms were cleaned and re-lubricated with a lanolin based lubricant there was a marked improvement in trip times. The procedures in the maintenance specifications were amended to reflect these findings.

Some of the older models are becoming difficult to maintain due to their construction and availability of spares. However these units are still maintained during the normal maintenance round. At this stage their operational capabilities have not been compromised and they are performing satisfactorily.

3.2.2 11kV LMVP Partial Discharge

There are ongoing problems with partial discharge on the RPS/Reyrolle LMVP CBs where the bus shutters meet the resin tank body. The CBs are inspected for partial discharge every two years. Where issues arise, remediation is carried out and the CB returned to service. We are working with suppliers to resolve this issue.

3.2.3 66kV DT09 Spring Charge Motor

The spring-charge motor on CB142 at Heathcote zone substation burnt out due to the drive gears jamming. The CB was replaced with a spare unit and the mechanism fixed under warranty by the supplier. A complete spare CB is maintained at all times in preference to a large number of emergency spare parts. This allows greater flexibility and minimises capital outlay on parts that may not be required.

4 ASSET CONDITION

4.1 GENERAL

Our CBs play an integral part in helping us provide a safe and reliable network. As a result it is imperative that they are maintained and kept in good condition.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our HV CBs. This model utilises asset information, engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the health index (HI) and probability of failure (PoF) of each individual CB. This effectively gives the CB a ranking which is used when determining the replacement strategy. Note that while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

The results of this process have shown that the overall condition of our CBs is very good and we are on target with our replacement programme.

Figure 4: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 5: Year 0 11kV Circuit Breaker Health Index

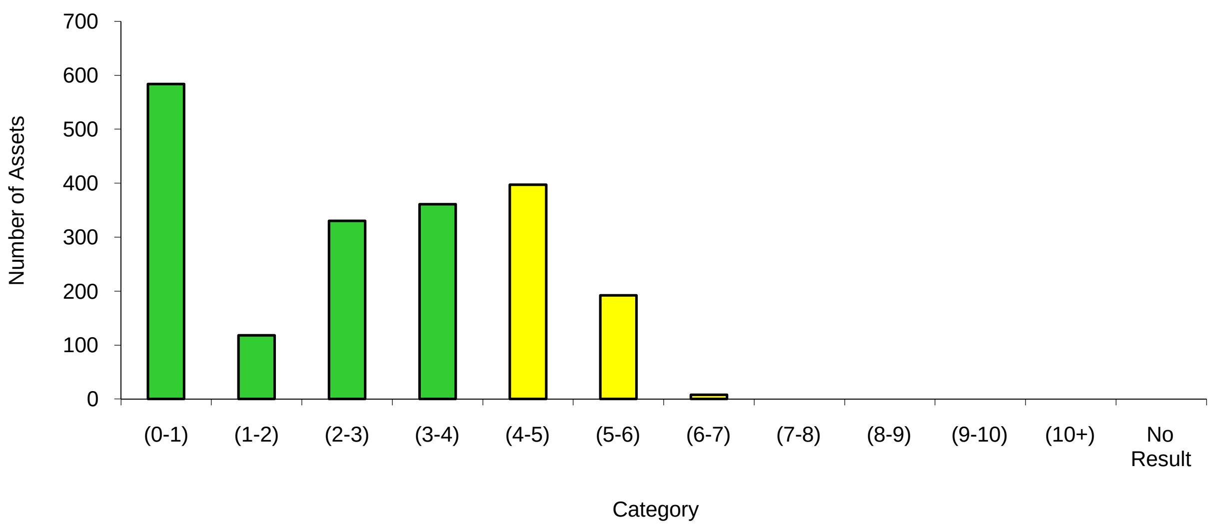
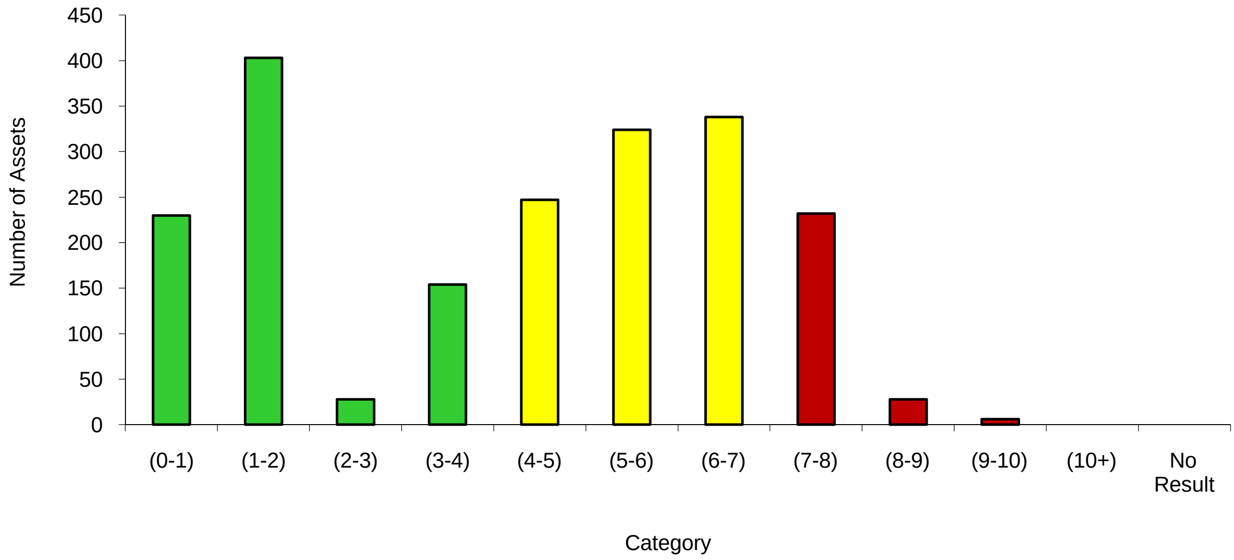


Figure 6: Year 10 11kV Circuit Breaker Health Index



Figures 5 and 8 show the current condition of our HV CBs. Figures 6 and 9 show the condition of our high voltage CBs in 10 years time if no further investment is made in the replacement programme.

Figure 7: Year 10 – % Replacement 11kV Circuit Breaker Health Index

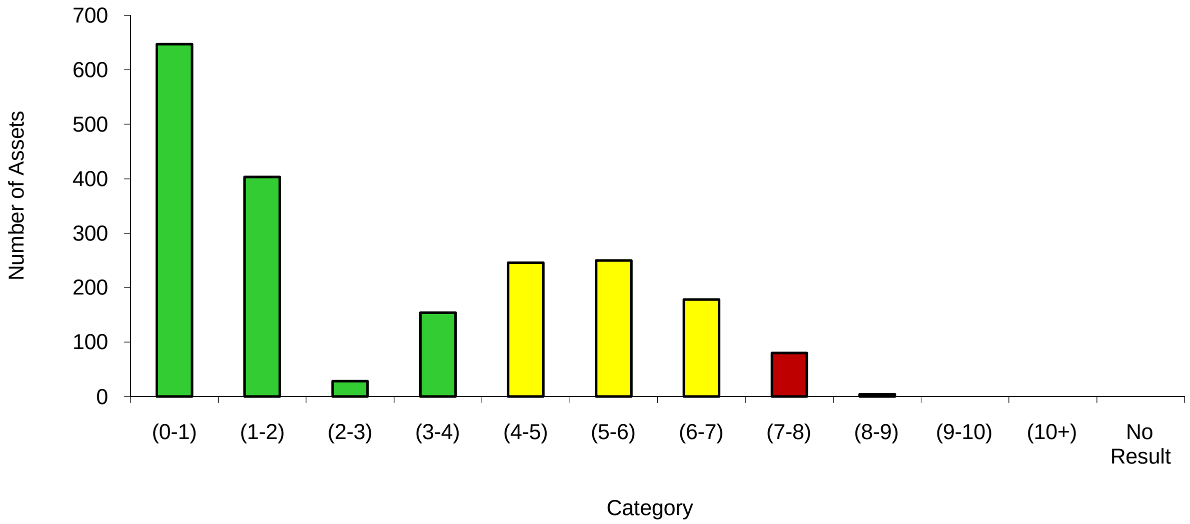


Figure 7 above illustrates the Year 10 condition profile of the 11kV CBs if a replacement rate of 2.1% is adopted. This rate enables us to maintain similar current profile. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

The year 0 plot shows the overall condition of our 11kV CBs is acceptable and we are on target with our replacement programme.

Figure 8: Year 0 33kV & 66kV Circuit Breaker Health Index

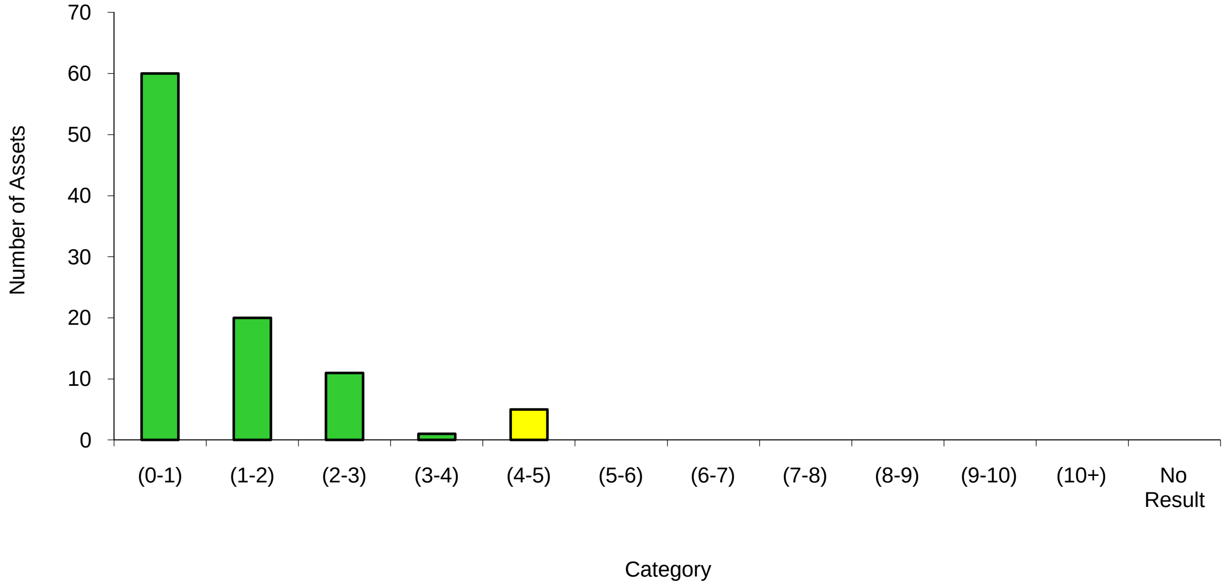


Figure 9: Year 10 33kV & 66kV Circuit Breaker Health Index

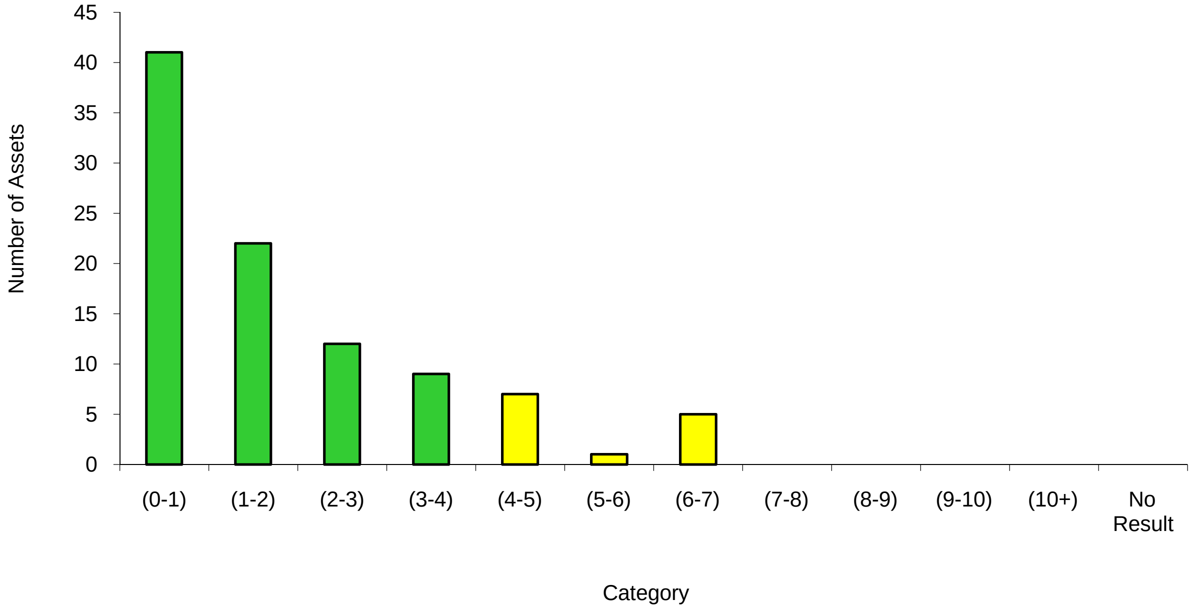


Figure 10: Year 10 – % Replacement 33kV & 66kV Circuit Breaker Health Index

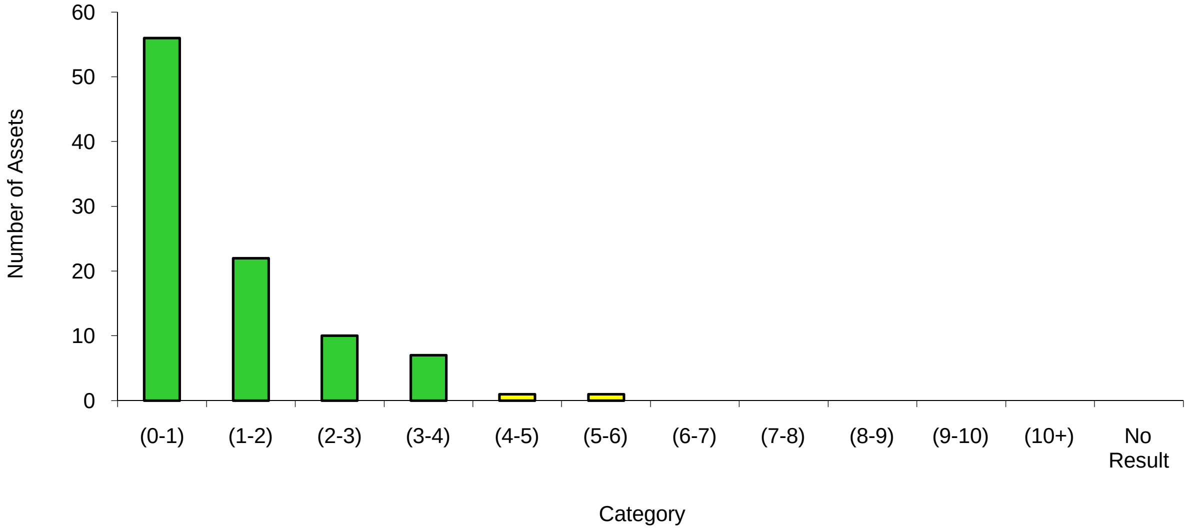


Figure 10 above illustrates the Year 10 condition profile if a replacement rate of 1.6% is adopted. This rate enables us to maintain our current profile. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

However the year 0 plot shows the overall condition of our 66kV and 33kV CBs is good and we are on target with our replacement programme.

The location of a CB within the network can have a significant impact on its lifecycle. For example, rural CBs tend to operate more often than those in urban areas. This is due to operational switching for load disbursement and the rural network being primarily reticulated with overhead lines, which by nature are more susceptible to tripping incidents than a cable network. Because these CBs are 'worked' harder, they have a shorter lifecycle than those in the urban network.

The placement of a CB indoors or outdoors also affects its nominal lifecycle.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

We use a mixture of maintenance processes to service our equipment. No single method provides the ultimate solution from an asset management perspective but by using a combination of them we can tailor our maintenance schedule to best suit our requirements.

At present our CBs are tested and maintained as detailed in Orion's Technical Specification:

- *NW72.23.07* – Orion Zone Substation Maintenance
- *NW72.23.06* – Orion Network Substation Maintenance

The CBs are checked during the substation maintenance rounds and results are recorded and minor adjustments made if necessary. Major faults result in the CB being removed from service and overhauled.

5.2 HIGH VOLTAGE CIRCUIT BREAKER LIFECYCLE

Traditionally the nominal lifecycle attributed to our CBs have been in line with industry best practice. The CBRM project has enabled us to better predict the lifecycle for individual CBs as it incorporates environmental and operational factors as well as failure modes and obsolescence.

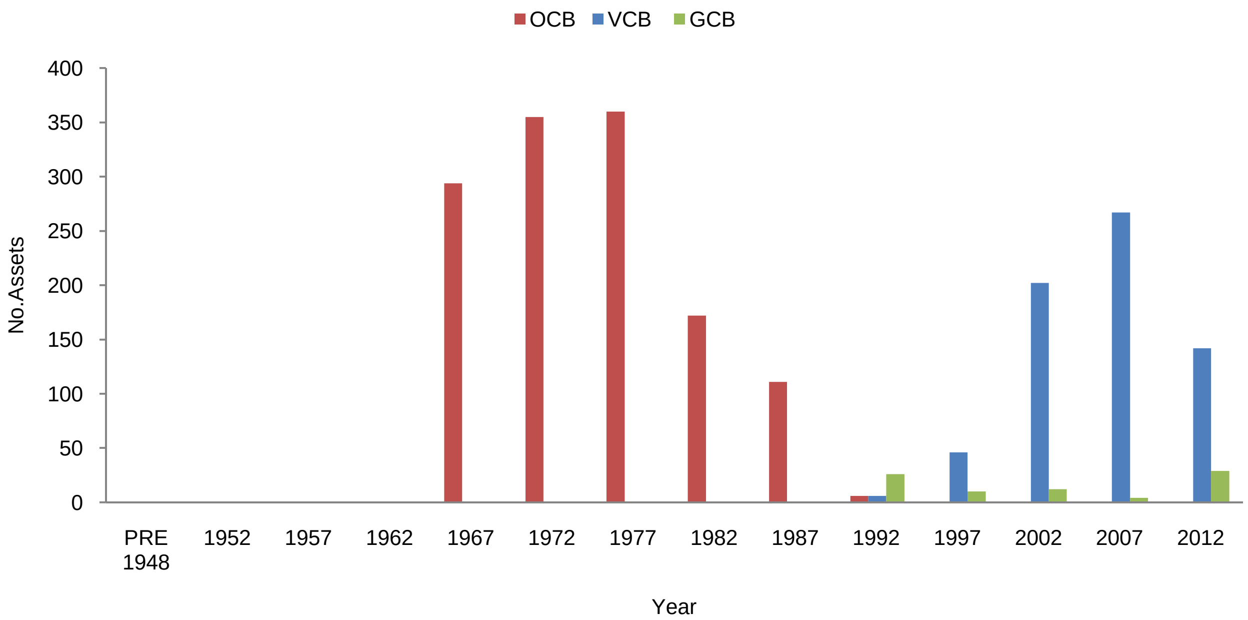
Figure 11: Nominal Life Cycle of High Voltage Circuit Breakers

Breaker Type	Industry Norm	Orion
66kV OCB	45	50
66kV GCB	45	60
33kV OCB	40	45
33kV VCB	50	60
11kV OCB	45	50
11kV GCB	45	50
11kV VCB	50	60
11kV Pole	30	35

Figure 12: Average Age of High Voltage Circuit Breakers

Voltage	Gas CB	Oil CB	Vacuum CB	Total
11kV	22	39	9	**28**
33kV		32	5	**17**
66kV	6	37		**9**
Total	**13**	**39**	**9**	**27**

Figure 13: Age Profile High Voltage Circuit Breakers



5.3 OIL FILLED CIRCUIT BREAKERS

All oil filled CBs are serviced following operation under fault conditions. The 66kV and 33kV units are serviced on site during the outage of the faulted equipment e.g. transformer, line, etc. The trucks of the 11kV CBs can be removed from site and serviced if there is a suitable spare available. This work is carried out under the Emergency Works contract and is covered in more detail in Orion's Technical Specification:

- *NW72.23.15* - Oil Circuit Breaker Servicing After Operation Under Fault Conditions.

5.4 FUTURE PURCHASES

All purchases of new CBs will meet the following requirements:

- where possible SF_6 shall be avoided
- arc contained to IEC 60298.

5.5 SULPHUR HEXAFLUORIDE – SF_6

SF_6 is a very effective interruption medium, but there are other lifecycle management factors to be considered. There are extra costs associated such as specialised equipment and training required for handling of SF_6 and its disposal. We are required to monitor the levels of all SF_6 we use (including storage) and report any loss-to-atmosphere. There are also extra costs associated with importing SF_6. These costs are reflected in the cost of the CB.

As a result our policy is not to purchase equipment containing SF_6 if there is a technically and economically acceptable alternative. The procedures for SF_6 use in our network are discussed in more detail in Orion's Technical Specification:

- *NW70.10.01 - SF_6 Gas Management Procedures.*

5.6 PARTIAL DISCHARGE

All metal-clad switchgear (33kV & 11kV indoor CBs) are tested for partial discharge. The programmes for these tests are dependent on the age of the switchgear and are outlined in Orion's Technical Specification:

- *NW72.27.03 – Partial Discharge Tests.*

This testing method has been useful in uncovering potential problems with switchgear at various locations throughout our network. As the CB population increases in age the cost of testing per annum will increase. Therefore an assessment of the test results for the last few years is underway to determine if the number of 'incidents' being found is decreasing. If this proves to be the case then the frequency of the partial discharge test can be pushed out to every two years rather than annually.

5.7 REPLACEMENT PLAN

Traditionally the replacement plan was driven by the age of the CB. Prior to the CBRM model being available we relied on the ranking system we developed in 2009. This year we used a combination of the asset ranking system and CBRM model. We will refine this process on an annual basis as we move from a time based replacement programme to one based on condition assessment and risk analysis. See Appendix A for replacement plan.

5.8 DISPOSAL PLAN

As these assets reach end of life they are disposed of as part of CB/switchgear upgrades, or where there is a safety or engineering reason.

5.9 SAFETY STANDARD REVIEW

A major component in determining the replacement plan and maintenance schedules is the 'Health Index' of each CB. The index ranking is obtained by the input of information into a CBRM model and takes account of the condition, age, reliability and obsolescence of a CB. It is updated annually.

Safety, maintenance and performance are the criteria considered for the replacement of CBs in the network. As a CB ages these criteria become more prevalent.

Safety to the public, staff and equipment is of the utmost importance. As a result most of the CBs that were considered a concern have been replaced. Any CBs that are considered a risk are refurbished or replaced.

Maintenance of the CB has to be cost effective. If a specific type has a common failure mode, is difficult to source spare parts for or is difficult to maintain then it is targeted for replacement.

Performance of the CB and its ability to interrupt fault current is directly linked to the safety of plant and personnel. If a CB does not meet the criteria indicated in its performance specifications an assessment will be carried out determine if it can be refurbished or replaced.

Age of the CBs is another factor considered. On average our HV CBs have a nominal service life of 40 to 60 years depending on the type and its application. We have a number of CBs in the network which are approaching the end of their lifecycle. These CBs will be targeted for replacement if they do not meet the safety, maintenance and performance criteria mentioned above, however they will remain in service as long as they do not become problematic.

We are currently reviewing the safety standards regarding arc containment during faults. The outcome of this review may lead to remedial work on or replacement of some older CBs.

5.10 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.11 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.12 RISK ANALYSIS

5.12.1 Network Spares

Our policy regarding CB spares for the network is to ensure that we have enough to respond to any risk to our security standard and contingencies for major event / disaster recovery. Reliability of the different CB types and their location in the network has an impact on the number of spares we carry. Determining the number of spares to carry is undertaken as part of the risk analysis process.

Figure 14: Number of High Voltage Circuit Breakers and Status

Voltage	Asset Spec	EMRG	SERV	STCK	Total
11kV	GCB	2	39	5	**46**
11kV	OCB	44	1186	2	**1232**
11kV	VCB	17	688	26	**731**
33kV	OCB		22	1	**23**
33kV	VCB		28	1	**29**
66kV	GCB		48	10	**58**
66kV	OCB		6		**6**

Note: Does not include CB's for removal, to be deleted or WIP or Sectionalisers

5.12.1.1 66kV Circuit Breakers

All of our 66kV CBs are outdoor types and while we have different models with different interruption mediums there is enough similarity between the units that they can be easily interchanged. Middleton zone substation is the only special case with a protection and metering configuration that requires six CTs.

The inter-changeability of these CBs means that we can minimise our stock holdings to one emergency spare 66kV CB rather than carrying one of each type.

5.12.1.2 33kV Circuit Breakers

It is a similar situation for our 33kV CBs. The outdoor units are inter-changeable with minimal modifications required on site. However these CBs are used in conjunction with either 5A or 1A secondary CTs depending on the protection relays used. As a result we carry one 33kV CB with 5A secondary CTs and one with 1A secondary CTs.

We carry one emergency spare CB truck for our 33kV vacuum indoor metal clad switchgear. These CBs are connected in a mesh configuration which provides greater flexibility when isolating any part of the switchboard that requires maintenance or replacement. This coupled with the fact that failures with vacuum CBs are rare means more than one emergency spare is deemed unnecessary.

5.12.1.3 11kV Circuit Breakers

The 11kV network is configured in such a way that if a CB fails, power can still be supplied to customers via another route. This flexibility means that it is not as critical if an 11kV CB fails compared to a 33kV or 66kV CB. Not all of the 11kV metal-clad CBs are inter-changeable, therefore we carry a higher number of spares. However we do not have an emergency spare for every type of 11kV CB.

The number of CB types in service for which we do not carry an emergency spare is small compared to the overall population of 11kV CBs. If one fails, an assessment will be carried out to determine if an existing emergency spare of a different breaker type could be used. If there are no suitable candidates available then it is likely that the damaged CB and suit of CBs would be replaced with new vacuum type.

5.12.1.4 11kV Sectionalisers

As sectionalisers are primarily found in the rural network where they are used for reliability improvement, the impact of one failing is low (there are only four in the network). If there is a failure and no spare available the sectionaliser can be bypassed. While we do not have replacements for every type of sectionaliser the units are somewhat interchangeable, so it is deemed that we carry sufficient spares for these units.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability. As all works are carried out during the winter substation maintenance programme we do not distinguish between CBs and switchgear for Opex.

Figure 15: Historical and Forecast Expenditure

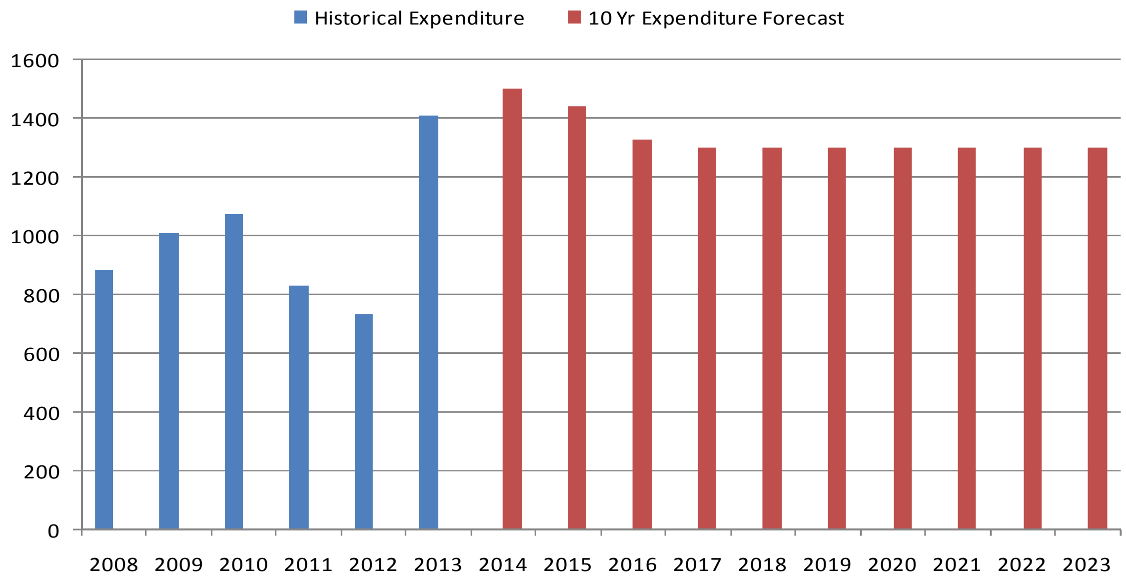


Figure 15 is a plot of our total historic and forecasted expenditure for both our CBs and switchgear. We do not separate our maintenance expenditure for these assets.

The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 16: Historical High Voltage Circuit Breaker Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	681	787	759	584	486	1177
Non-Scheduled	107	99	164	200	174	125
Emergency	100	126	151	48	74	110
Total	**888**	**1012**	**1074**	**832**	**735**	**1412**

At the time of writing, the budgeted rather than actual expenditure figures were used.

Figure 17: High Voltage Circuit Breaker Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	1225	1165	1025	1025	1025	1025	1025	1025	1025	1025
Non-Scheduled	125	125	125	125	125	125	125	125	125	125
Emergency	150	150	180	150	150	150	150	150	150	150
Total	**1500**	**1440**	**1330**	**1300**	**1300**	**1300**	**1300**	**1300**	**1300**	**1300**

Our CB scheduled maintenance is carried out as part of our wider substations maintenance which also includes HV and LV switchgear. Therefore, we do not separate the expenditure forecasts. This work is tendered as part of our contracting model.

Our non-scheduled maintenance forecast is for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that requires our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 18: Historical and Forecast Expenditure

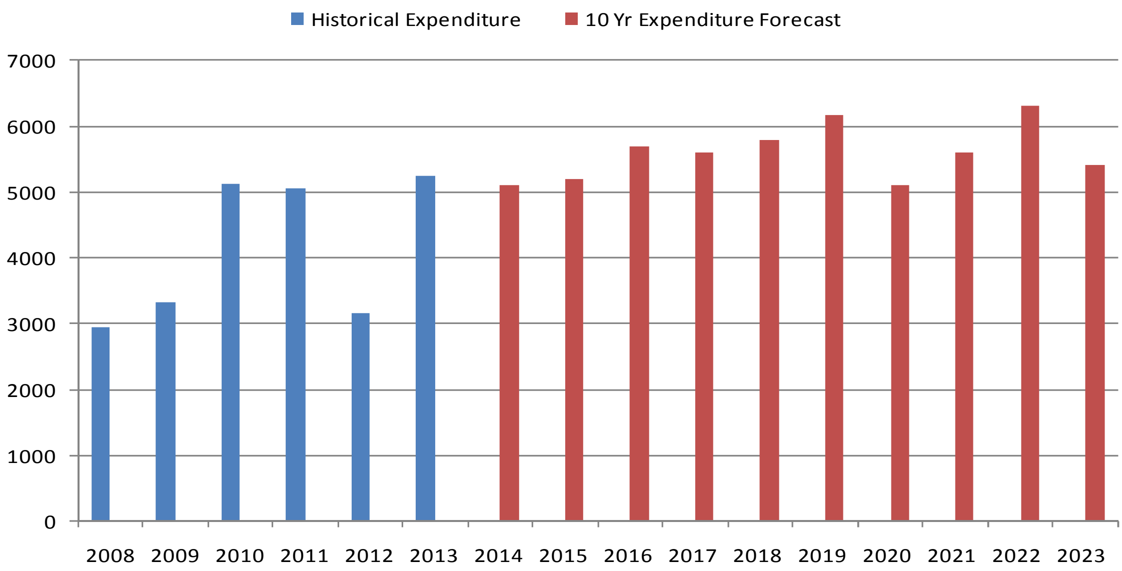


Figure 19: Historical High Voltage Circuit Breaker Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	2956	3337	6084	5043	3155	5255
Total	**2956**	**3337**	**6084**	**5043**	**3155**	**5255**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

Figure 20: High Voltage Circuit Breaker Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	5094	5191	5699	5598	5785	6168	5099	5601	6309	5423
Total	**5094**	**5191**	**5699**	**5598**	**5785**	**6168**	**5099**	**5601**	**6309**	**5423**

Voltage Regulators

Asset Management Report YE 2012

NW70.00.41

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1 INTRODUCTION

Voltage regulators are installed at strategic points where voltage support is required throughout our network to automatically regulate the 11kV voltage.

This document covers each of our regulator categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these regulators.

2 ASSET DESCRIPTION

2.1 GENERAL

Regulators are installed at various locations on the 11kV network to perform two different functions:

- provide capacity (via voltage regulation) for security against the loss of a zone substation
- provide automatic voltage regulation on fixed tap transformers.

We use a wide range of ratings, from 550kVA to 20MVA, to cater for different load densities within our network. All regulators are oil filled, with automatic voltage control by an on-load tap-changer or induction. The installation designs allow for quick removal and re-installation.

We have regulators from four manufacturers currently on our network – AEI, ASEA, McGraw Edison and Siemens.

Figure 1: Voltage Regulators

Manufacturer	No.	Ave Fin Year	Avg Age (Yrs)
AEI	3	1962	50
Asea	1	1955	57
McGraw Edison	3	1989	23
Siemens	11	2003	9
Total	**18**	**1991**	**21**

3 ASSET PERFORMANCE

Voltage regulators in our network are capable of operating continuously at their rated capacity. Detailed data records of the number of tap-change operations are compiled via the SCADA system. This data is analysed regularly.

Our regulators suffered virtually no damage in the earthquakes.

4 ASSET CONDITION

4.1 GENERAL

The AEI regulators at Heathcote are of an older design. Regulators R1 and R2 were refurbished before being put into service with Orion and are working satisfactorily. In 2010 a third regulator (R3) was installed to provide security for the Lyttelton supply.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our voltage regulators. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual regulator. This effectively gives the regulator a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Figure 2: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 3: Year 0 Health Index Profile

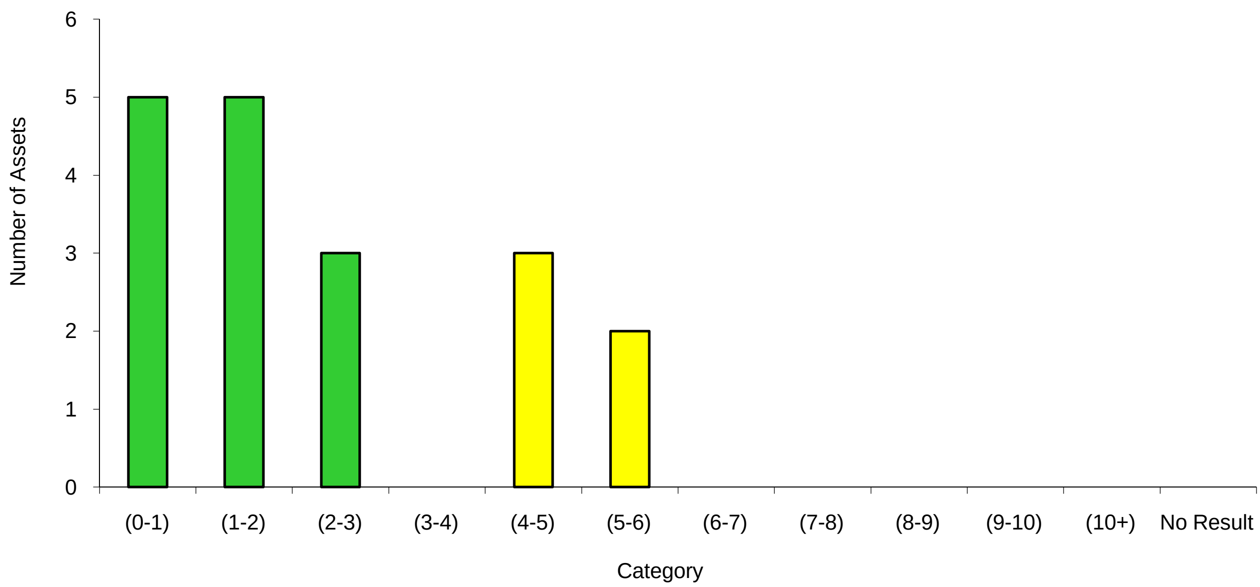


Figure 4: Year 10 Health Index Profile

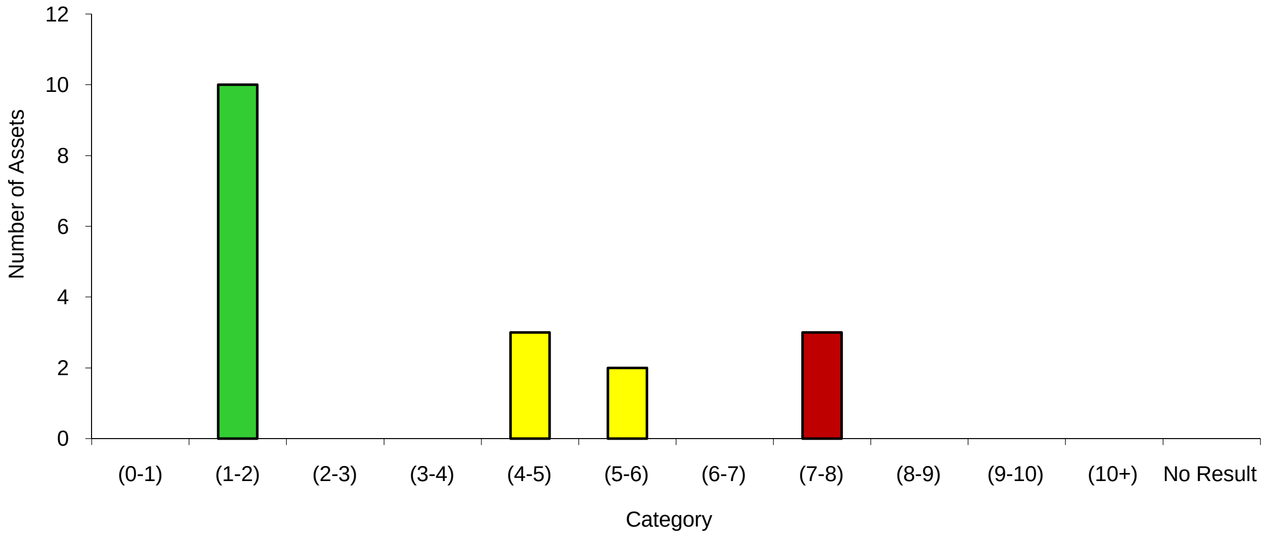


Figure 3 shows the current condition of our regulators. Figure 4 shows the condition of our regulators in 10 years time if no further investment is made in the replacement programme.

Figure 5: Year 10 – % Replacement Health Index Profile

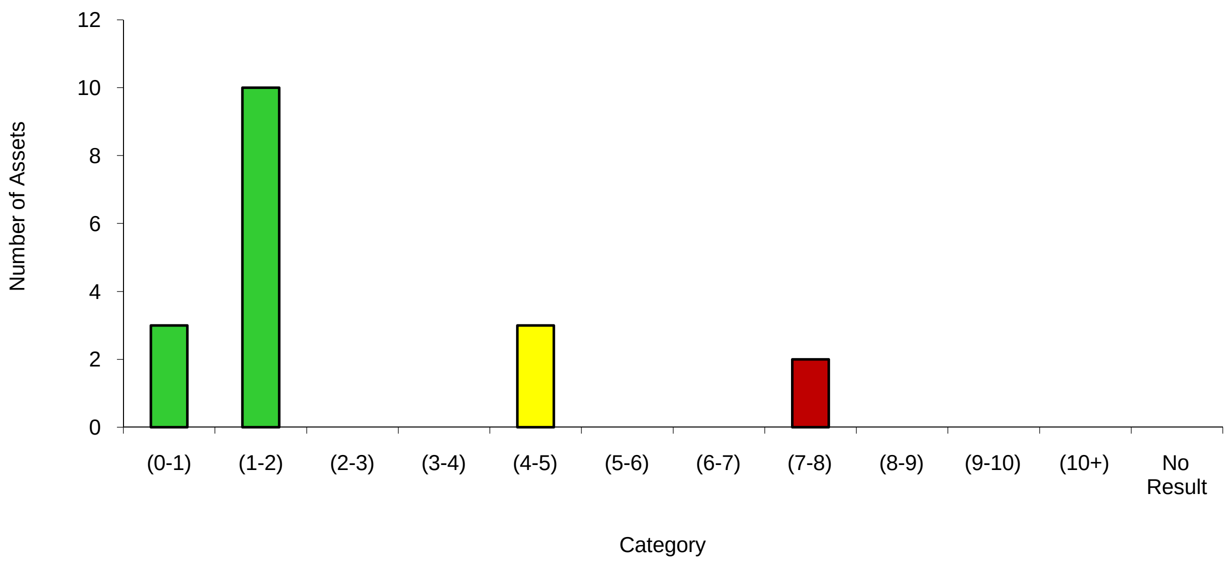


Figure 5 above illustrates the year 10 condition profile if a replacement rate of 2% is adopted. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

However the year 0 plot shows the overall condition of our regulators is good and we are on target with our replacement programme.

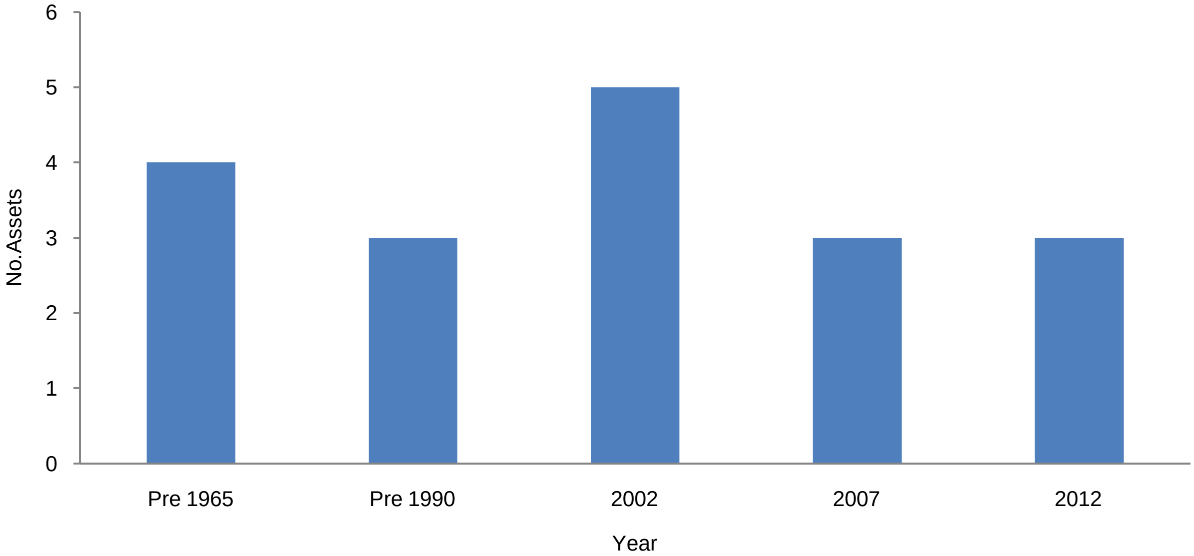
4.3 HISTORICAL ISSUES

The bypass arrestors on the Siemens regulators have failed at a few sites causing damage to the bushings. There was a problem with lose fixed-contacts resulting in the moving contacts having to be replaced.

5 ASSET MANAGEMENT PRACTICES

5.1 VOLTAGE REGULATORS LIFECYCLE

Figure 6: Age Profile Voltage Regulators



5.2 MAINTENANCE PLAN

Voltage regulators installed at our zone substations are included in the annual and four-yearly tap-changer maintenance programmes. The new 4MVA regulators are included in a separate section of the distribution maintenance round and are serviced on an eight-yearly cycle.

Operator Instruction Standards:

- *NW72.13.201* 11kV Regulator Ferranti
- *NW72.13.203* 11kV Regulator ASEA
- *NW72.13.204* 11kV Regulator Siemens

Maintenance Standards:

- *NW72.23.01* *Mineral Insulating Oil Maintenance*
- *NW72.23.07* *Zone Substation Maintenance*
- *NW72.23.22* *Inst*allation or Changing regulators on O/D Pad mounted sites

5.3 REPLACEMENT PLAN

The capacity of a voltage regulator is the main driver for replacing it or relocating it to another part of the network. As local load requirements increase an assessment is carried out to determine if an existing regulator is sufficiently rated. If the load exceeds the rating of the regulator an assessment will be made as to whether replacement is required. We will also refer to the CBRM model results for context on the regulator's condition.

5.4 DISPOSAL PLAN

The 550kVA ASEA regulator installed at Annat zone substation is undersized for the current capacity. A project is currently underway to replace it with a refurbished 1000kVA Turnbull and Jones regulator.

5.5 CREATION/ACQUISITION PLAN

Our current preferred supply for voltage regulators is Siemens. We use an “off the shelf” SFR type 3 phase voltage regulator to provide +/- 10% regulation in 32 steps of 5/8% each.

5.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.7 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

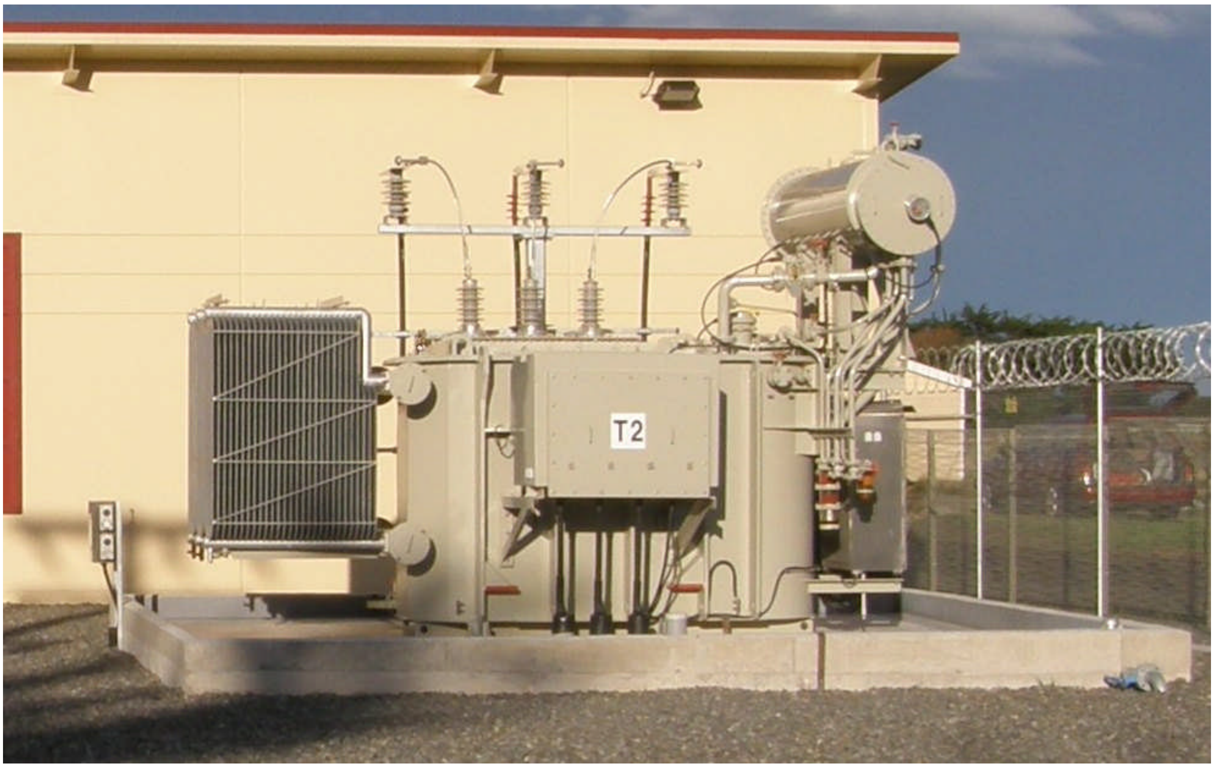
Currently our regulator expenditure is carried out as part of our wider maintenance programmes and as a result cannot be easily separated out.

6.2 REPLACEMENT EXPENDITURE

New regulators are purchased as part of reinforcement projects. We currently do not have any plans to replace any of our regulators.

Power Transformers

Asset Management Report YE 2012



NW70.00.23

Table of Contents

1 INTRODUCTION

Power transformers are installed at our zone substations to transform sub-transmission voltages of 66kV and 33kV to our distribution voltage of 11kV. These assets are expensive to replace and often have long lead times. As a result effective asset management techniques are required.

This document covers each of our transformer categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these units.

2 ASSET DESCRIPTION

2.1 GENERAL

Power transformers transform sub-transmission voltages to distribution voltages. Any fluctuation in the sub-transmission voltage will be reflected in the distribution network. As a result all of our power transformers are fitted with regulating equipment to maintain the required network operating voltage. We have a total of 71 power transformers (including spares) in the network. Refer Figure 1 for a breakdown of transformer nominal voltages and ratings.

Figure 1: Zone Substation Power Transformers

MVA	34/40	20/40	11.5/23	10/20	7.5/10	7.5	2.5	Total	Av. Age*
33kV	-	-	7	4	5	13	4	33	35yrs
66kV	2	23	7	-	6	-	-	38	25yrs

* Average age in 2012

2.2 URBAN 20/40MVA 1969 – 1986

- Two different manufacturer types - Ferranti and Tyree
- 66/11kV voltages only.
- Dual rated with a separate cooling tower. These units use OFAF (Oil Forced and Air Forced) cooling.

These transformers are normally enclosed in buildings for noise reduction when located near residential areas. The transformers at Hawthornden, Heathcote and Rawhiti are located outdoors in 66kV switchyards. The Milton transformers are also located outdoors but are not part of a 66kV switchyard as they are cable/cable connected.

The Ferranti transformers can be configured for cable box or bushing connection. Cable connections are used when the transformer is located in a dedicated building. Eight have been converted to HV bushing connections for use in switchyards.

All of the Tyree units have HV cable boxes. It is our belief that these can be modified to use a top bushing connection. A project is being developed to convert TYR18437 at Heathcote from HV cable connection to HV bushings. This enables us to replace the oil filled cable currently used to supply the transformer with over head conductor thus reducing our maintenance requirements on site.

Each of the 20/40MVA units in this category is interchangeable with only minor modifications required on site. Note: the footprint of each transformer manufacturer type is slightly different.

2.3 URBAN 20/40MVA 2001 – 2007

This category contains only Pauwels transformers which are located at Lancaster and Middleton zone substations. These transformers have the following characteristics:

2.3.1 Lancaster

- 34/40MVA but electrically optimised for 20MVA rating.
- 66/11kV voltages only.
- Dual rated with an integrated cooling tower. These units use ONAF (Oil Natural and Air Forced) cooling.
- Located outside in a 66kV switchyard in a light industrial area. Both units are bushing connected on the HV side and cable box on the LV.
- These units are physically larger than the Ferranti and Tyree units and are not interchangeable without significant modifications to the switchyard.

2.3.2 Middleton

- 20/40MVA
- 66/11kV voltages only.
- Dual rated with an integrated cooling tower. These units use ODAF (Oil Directed and Air Forced) cooling and are physically smaller than the Lancaster transformers.
- Located outside in a 66kV switchyard in a light industrial area. Both units are bushing connected on the HV side and cable box on the LV.
- These units are not interchangeable with the Ferranti and Tyree units without modifications to the switchyard.

2.4 11.5/23MVA

There are two sub-transmission operating voltages in the network therefore the following category is split into two sub-sections:

2.4.1 66/11kV Operating Voltage

- Seven units manufactured by Pauwels.
- Dual rated with integrated cooling tower. These units use ODAF cooling.
- Located outside in 66kV switchyards (Barnett Park, Halswell, Hawthornden & Weedons).
- HV bushing connections and LV cable connections.
- The Halswell and Hawthornden units are interchangeable.

The Barnett Park and Weedons Units are interchangeable, with reconfigurable Dzn3 – Dzn2 windings to allow connection to both the rural and urban networks. They are designed to run quieter than the units at Halswell and Hawthornden and as a result have a different cooling configuration. While the bushing and cable box connections are the same the position of the radiators means the transformer has a slightly different footprint and bund construction. This design will be used for all future transformers for this size.

2.4.2 33/11kV Operating Voltage

- Five different manufacturers – Brush (1), Ferranti (1), Tolley (3), Tyree (1) and Pauwels (1).
- Dual rated with separate cooling towers, except PAU05-P-0039 (Larcomb T1) which has an integrated cooling tower.
- Located in 33kV switchyards, therefore all of the units are outside. At Moffett zone substation the transformers are semi-enclosed by an acoustic barrier.

- Predominantly configured as bushing/bushing, except for the unit at Larcomb substation. This unit has a bushing/cable configuration.

To some extent these units are able to be interchanged. While the HV and LV connections are similar each transformer type has a different footprint. However only minor modifications are required if the transformers are swapped like for like. The Pauwels unit is not easily interchanged with the other units.

Sockburn T1 (BRU72619) has a rating of 11.5/18/23MVA. This unit uses OFAF cooling and has a continuous rating of 18MVA when both the oil pump and fans are running. The 23MVA relates to the short term (approx 1 hour) emergency rating of the transformer. The load at Sockburn substation is restricted by the 33kV supply cables. Therefore it is unlikely that T1 will be subjected to a load greater than 18MVA. By placing this unit in parallel with two other transformers the risk of it having to operate at its emergency rating, even during an N-1 contingency, has been further reduced.

2.5 10/20MVA

- Four units manufactured by Tyree.
- 33/11kV voltages only.
- Dual rated with integrated cooling towers.
- Completely interchangeable with each other.

There is no dedicated spare 10/20MVA transformer. If one of these units was to catastrophically fail it would be replaced with an 11.5/23MVA unit, thus requiring minor modifications to the site.

All these units have a 20MVA dynamic rating and are installed at Hornby and Sockburn zone substations. The first pair purchased was Sockburn T2 (TYR17845) and Hornby T1 (TYR17846). These units have 5 radiators each and it's understood that they may be capable of a higher dynamic rating. The nameplate rating is sufficient for the local load at present thus investigating if these transformers can be re-rated is not currently a priority. The second pair, purchased a year later, was Sockburn T3 (TYR18067) and Hornby T2 (TYR18068). These units have 4 radiators.

2.6 7.5/10MVA

2.6.1 66/11kV Operating Voltage

- Six units manufactured by Pauwels.
- Dual rated with integrated cooling tower.
- Located outside in single bank 66kV switchyards. Note only Dunsandel is a dual bank substation in this category.
- HV bushing connections and LV cable connections.
- Interchangeable with minimum modifications required.
- Three of these units have been ordered with a reconfigurable secondary winding. i.e. Dzn3 – Dzn2. This enables greater flexibility as to where these units can be located. Note: there is a 30° phase shift between the urban and rural network.

Transformer T1 (PAU04-P-0057) at Dunsandel is subject to a commercial agreement with Synlait allowing its removal from Dunsandel substation for use as an emergency spare elsewhere in the network.

2.6.2 33/11kV Operating Voltage

The 7.5MVA CANZAC (Tolley) and OEL transformers in our network are deemed to be of a robust design. Extensive research and testing was undertaken to determine if these transformers were capable of operating at 10MVA without adversely their performance or service life. The results were favourable and fans were added to TOL10393 and TOL10394 (Rolleston T1 & T2) in 2006. The two OEL units at Lincoln zone substation, OEL5579 and OEL5577 were converted in 2009. It is not feasible to convert these units to OFAF as the capillary holes in the radiators are too small to cope with an increased oil flow.

This procedure will be used again if it is economically feasible to up-rate more 7.5MVA transformers as local load increases. The cost of undertaking this method is approximately 35% of the total cost for a new transformer. By adopting this strategy not only is there a saving in capital outlay but in many cases the operational life of the transformer is also extended.

There are five transformers in this category, One ABB unit at Bankside, two Tolley units at Rolleston and two OEL units at Lincoln substation. These units have the following characteristics:

- Three different manufacturer types – ABB, OEL and Tolley
- Dual rated with integrated cooling tower.
- Located outside in 33kV switchyards. Note Bankside is a single bank substation while Rolleston is dual bank.
- HV bushing connections and LV bushing connections.
- Interchangeable with minimum modifications required.

2.7 7.5MVA

There are 13 7.5MVA transformers in service in the network. All of these units are installed in 33kV rural substations and have the following characteristics:

- Single rating with integrated cooling tower, no fans (ONAN), Except Springston T1 which has a separate cooling tower.
- Bushing – bushing configuration except for Diamond Harbour T1 and Motukarara T2 which are bushing – cable.
- Interchangeable with minor modifications required.

Four of the substations are dual bank substations. Note Motukarara substation has a 7.5MVA and a 2.5MVA transformer. The 2.5MVA unit (T1) is run in hot standby. While the transformers are not run in parallel, thus not load sharing, the substation is still classed as a dual bank site for N-1 contingency planning.

Diamond Harbour T1 and Motukarara T2 were specified and manufactured to enable them to be up-rated to 10MVA with the addition of cooling fans. These transformers have and extended tap range on their Reinhausen units. At present there is a 2.5MVA transformer installed at Teddington zone substation. If Diamond Harbour T1 is lost there is insufficient capacity at Teddington to support the 11kV load at Diamond Harbour. To mitigate this issue the PAU06-P-0031 at Motukarara will be relocated to Teddington in the near future.

2.8 2.5MVA

There are four 2.5MVA transformers in service in the network. All of these units are installed in 33kV rural substations and have the following characteristics:

- Single rating with integrated cooling tower, no fans (ONAN)
- Bushing – bushing configuration.
- All these transformers are installed in single bank substations except Motukarara T1 which is installed in conjunction with a 7.5MVA unit.
- Interchangeable with minor modifications required.

- As load increases in the network these units will be phased out of service and replaced with 7.5MVA transformers.

It is not economically viable to up-rate 2.5MVA transformers by adding fans. Nor is it viable to carryout half life maintenance on these units. These transformers will be phased out and be replaced with 7.5MVA units as load increases in the network or their condition deteriorates.

3 ASSET PERFORMANCE

The operating temperature of a transformer has a direct correlation with life expectancy. Our power transformers are capable of operating continuously at their rated capacity or at a higher rating for short period's dependant on the ambient temperature. Detailed data records of electrical loading on the transformers are compiled via the SCADA system. This data is analysed on a regular basis and we are in the process of developing thermal chain models for each of our zone substations to determine the overall site capacity.

New transformers are purchased with ratings designed to match the load requirements for the duration of their operational life. An investigation was undertaken to determine the capacity and performance of our older 20/40MVA transformers at warmer than average ambient temperatures. It was found that they were originally specified for an ambient temperature of 5°C. As a result operational procedures have been initiated to dynamically manage the capacity of these units when the ambient temperature exceeds 30°C.

Orion has two distinct peak load periods that affect the urban and rural networks at different times. The rural peak load occurs during summer and is predominately due to irrigation. With the increased development of residential subdivisions to the south and southwest of the city the winter load for the rural area is increasing slightly. However by comparison with the summer load the rural winter load is relatively low.

The peak load period for the urban network occurs in winter and is attributed to heating and lighting. The summer load for the urban network has not been significantly affected by the use of domestic heat pumps for cooling.

In general Orion's power transformers perform very well. We have had problems with the DIN bushings, installed on Pauwels transformers, leaking oil. We are currently working to solve this problem, and believe it is a combination of bushing design and installation techniques. An alternative bushing manufacturer has been specified for future units.

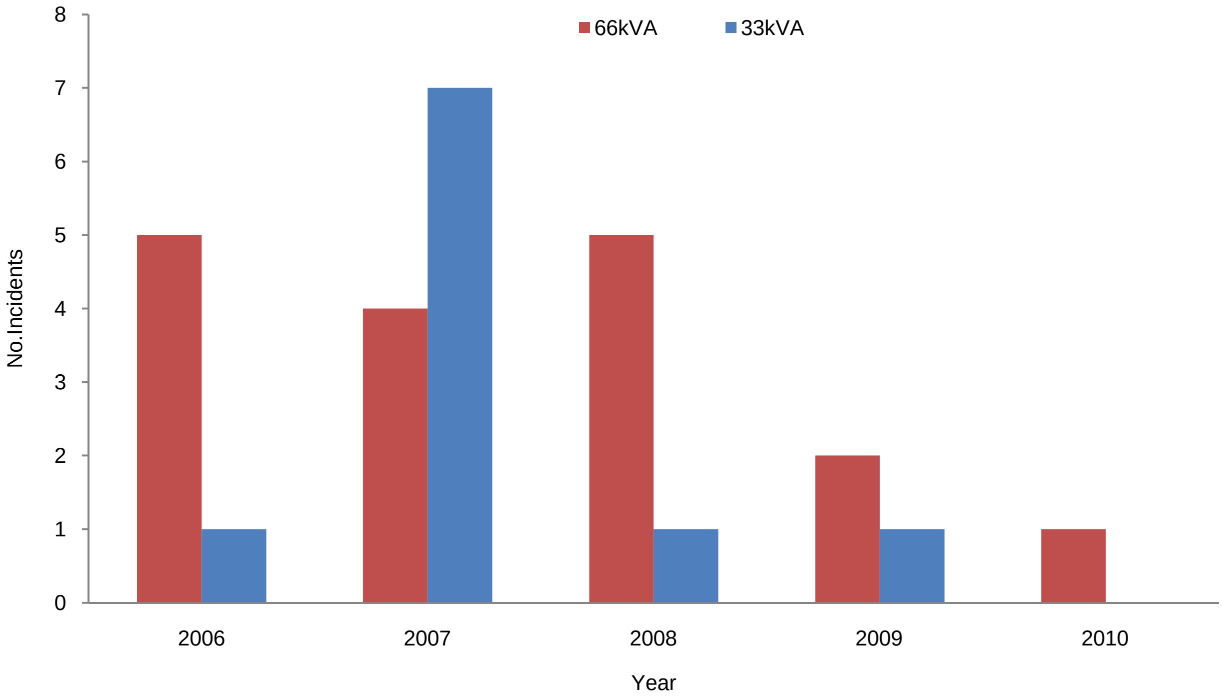
Little River T1 (GEC33K7823-1) developed a gassing problem in 2010, showing elevated levels of Hydrogen, Ethylene and Ethane. We are currently monitoring this unit through regular DGA analysis.

The Buchholz relays on Killinchy T1 (PAU00-P-0045) and Te Pirita T1 (PAU01-P-002) have both had spurious tripping, caused by water leaking into the junction boxes.

Shands Rd T1 (FER160739) suffered a collapsed coil which was repaired in 1998.

During the recent earthquakes our transformers generally performed favourably, except for some spurious tipping caused by mercury switches fitted in Buchholz relays. A project was carried out to replace all these with a seismically rated type.

Figure 2: 33/66kV Power Transformer Performance



4 ASSET CONDITION

4.1 GENERAL

While the external condition of a transformer and its bushings are important it is not a true indication of the assets condition. Oil and winding insulation condition have a major impact on the performance of a transformer. As a result testing and sampling of these mediums are regularly undertaken as part of the scheduled maintenance of the transformers.

These results are analysed and compared against a set of condition criteria and a ‘Transformer Condition Score’ is determined. Refer Appendix A for transformer rankings.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

By using a variety of assessments, ranging from visual inspection, insulation testing and oil tests we can monitor the condition of individual transformer units.

This monitoring programme often highlights any issues before they arise, allowing preventative maintenance or refurbishment to take place.

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our transformers. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual transformer. This effectively gives the transformer a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Figure 3: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 4 shows the current condition profile of our power transformers. We have a programme in place to mitigate issues with units with a health index of 6 and higher.

Figure 4: Year 0 Health Index Profile

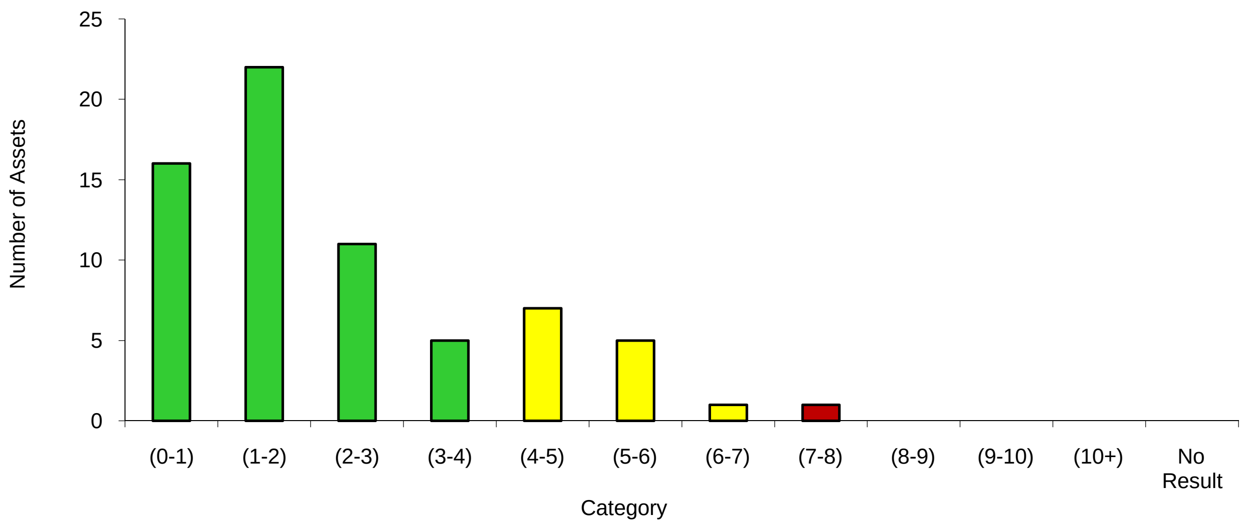


Figure 5 shows the condition of our power transformers in 10 years time if no intervention/refurbishment is undertaken.

Figure 5: Year 10 Health Index Profile

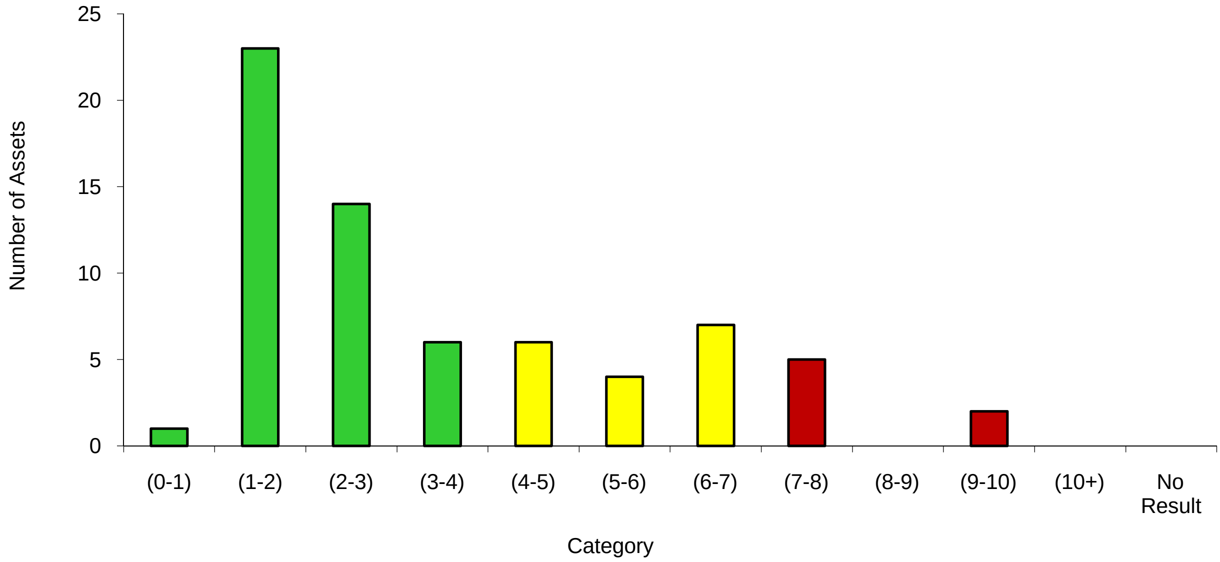
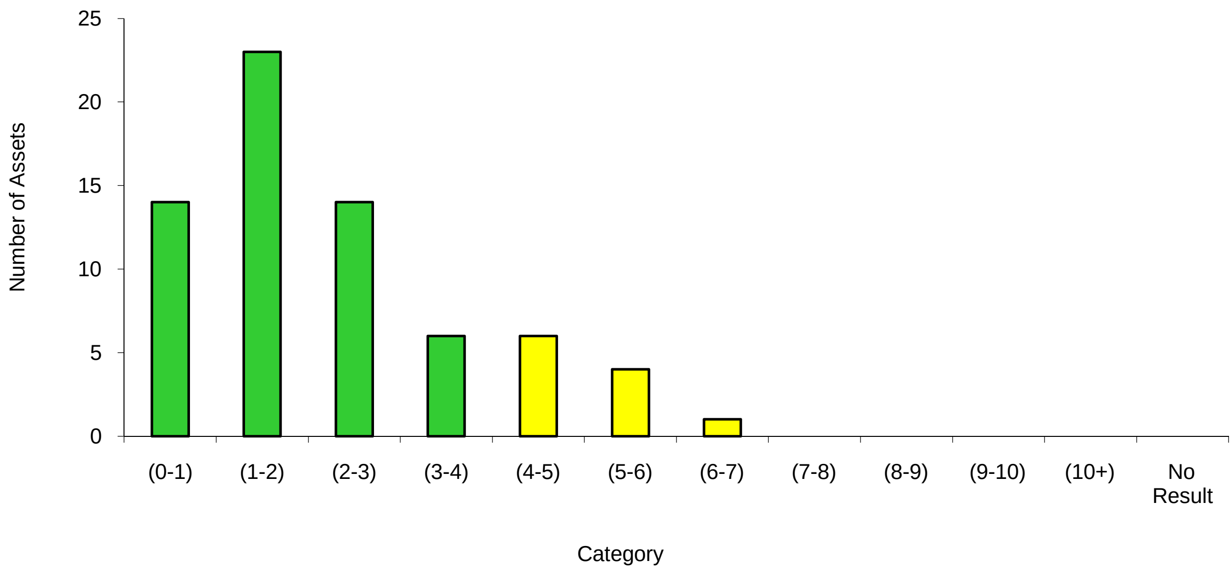


Figure 6 shows the year 10 condition profile if a replacement rate of 10% is adopted. As our population is so small this equates to replacing one unit. The results are also based on the assumption that we will continue with our half life refurbishment programme.

Figure 6: Year 10 - % Replacement Health Index Profile



4.3 HISTORICAL ISSUES

Historically it has been tap-changer mal-operation that has been the cause of transformer failure. As a result a proactive tap-changer maintenance/refurbishment programme was implemented. Initially Fuller tap-changers were targeted for replacement with Reinhausen vacuum units. Only one of these problematic units remains in service.

- Springston T1 (BRU69923)

Springston is scheduled for retirement in 2015 when the substation is upgraded to 66kV and we have taken ownership of the current Transpower assets.

4.3.1 ABB1341101

The tap-changer on ABB1341101 (Bankside T1) initially suffered from carbon build up on its contacts. This condition is prevalent for this design and as a result ABB have installed a circulating pump and filter as well as replacing the tap-changer inner shaft. This solution has proved successful but it has added an extra element to the maintenance regime as the pump runs continuously and the filter requires changing.

4.3.2 FER160739

In 1995 it was found during routine maintenance that the HV winding on the Ferranti transformer at Shands zone substation (FER160739) had collapsed. While it was essentially rebuilt after the incident its ability to operate at full load may have been affected.

4.3.3 TOL38681

The Tolley transformer at Shands zone substation (TOL38681) has a suspected issue with its oil flow flap. This restricts the flow of oil which causes the transformer to operate hotter under load conditions. While this issue doesn't affect the transformer under normal load conditions it does restrict the amount of load we can subject the transformer to during an N-1 event.

A project is being developed to test both of the transformers at Shands Rd to confirm their nameplate ratings.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

We employ a number of different asset management practices for different asset management practices for different asset groups.

5.2 TRANSFORMER LIFECYCLE

We assign a nominal service life of 70 years to a power transformer. Due to our security standard of N-1 contingency planning for all zone substations many of the transformers are lightly loaded. Very rarely will a power transformer in the network be required to operate at its maximum loading for a long period of time. This and the maintenance practices employed mean we are confident of extending the service life of our power transformers to 80+ years.

A major component in determining the replacement plan and half life maintenance schedules is the health index attributed to each transformer. The CBRM model takes into account the reliability and condition of the transformer and is updated on an annual basis. Currently the reliability and condition of our power transformers is very good.

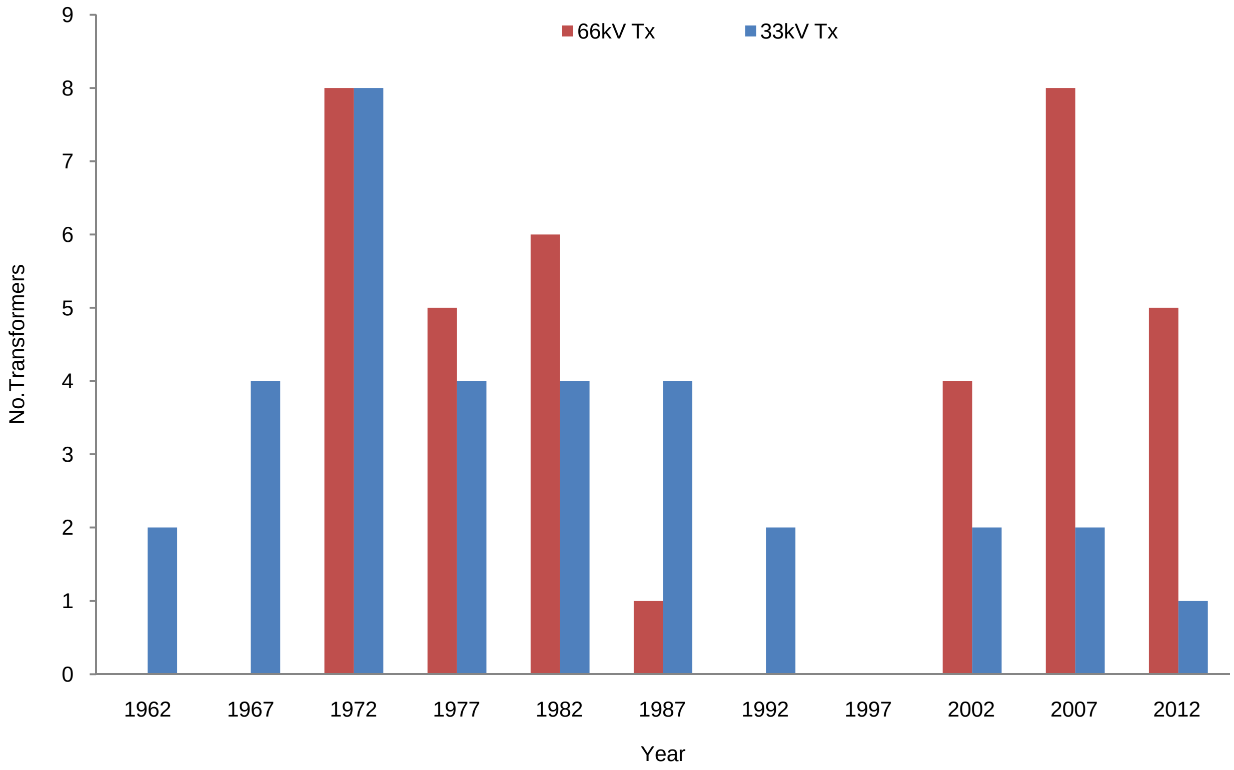
Winding hot spot temperature has the greatest effect on the life cycle of a transformer and is directly related to load current. Our 33kV units have primarily been installed in single-bank substations in rural and industrial areas to the west of the city and have been subjected to higher base and cyclic loads. However testing thus far has not shown any adverse affects due to heating.

The majority of the 66kV units have been installed in dual-bank substations and are rarely subjected to full load and often operate below 50% full load. It is feasible that we can expect 80+ years of service from these units.

One method of determining the life expectancy of power transformers is to analyse the degree of polymerisation (DP) of the insulating papers in the unit. Due to the similarity of our transformer designs and operating conditions only 15 transformers have been tested.

Condition of the oil and insulation of a transformer have a major impact on its performance. As a result testing and sampling of these mediums is undertaken during the routine maintenance rounds. The procedures include testing the degree of polymerisation (DP) of the insulating papers and water content in the oil. In summary a transformer that has a DP of 200 or less or a percentage relative saturation over 21% will be targeted for remedial works or replacement.

Figure 7: Age Profile - Power Transformers



5.3 CREATION/ACQUISITION PLAN

When procuring power transformers we take into consideration the design of existing units. This allows inter-changeability between sites giving greater flexibility in fault situations and minimising the number of spares.

Procurement Standards

- *NW74.23.07* – Transformer Primary 66/11kV 7.5/10MVA
- *NW74.23.16* – Transformer Primary 66/11kV 11.5/23MVA
- *NW74.23.24* – Transformer Primary 66/11kV 40MVA

5.3.1 Voltage Regulation and Fault Levels

Power transformers are equipped with tap-changers that can be operated on load. Fault current levels are a direct result of impedance. In an effort to reduce substation fault levels we purchase transformers with impedances shown in Figure 8.

- *NW70.50.05* – Network Design Overview: defines that the 11kV fault level is to be kept less than 250MVA.

Figure 8: Power Transformer Impedances

MVA	7.5 - 10	11.5/23	10/20	20/40
Impedance	7% - 8%	8% - 13%	8%	13% - 14%

* Approximate values

5.3.2 Noise Consideration

The district and city plans have clear requirements that must be adhered to. In the past power transformers in urban areas have been enclosed in buildings to mitigate operating noise issues. It is not feasible from an engineering perspective to install cooling towers indoors and while there is a constant hum for the transformer it is the operation of the cooling fans that have the highest effect on dB readings.

We have taken a two pronged approach to this issue. Transformers that have a dual cooling system are set to operate their pumps to provide stage one cooling and then the fans for stage two. This reduces the overall run time of the fans. Note that dual cooling is normally found on units 11.5/23MVA and bigger.

The second approach is to ensure that new transformers are purchased with 'low noise' fans and pumps. While noise pollution is not normally an issue in our rural substations the requirement to be able to swap units between our rural and urban networks means that all new transformers will be as such.

5.4 MAINTENANCE PLAN

At present our power transformers are tested and maintained as part of the zone substation maintenance and inspection rounds as detailed in Orion's Technical Specifications:

- *NW72.23.01* – Mineral Insulating Oil Maintenance
- *NW72.23.07* – Zone Substation Maintenance
- *NW72.23.25* – Power Transformer Servicing

5.4.1 Half Life Refurbishments

We carry out refurbishments on power transformers when they reach their half-life at 40 years. With the progression into condition based maintenance though, the refurbishments will be dictated by a health score which will be driven by a number of condition indicators, rather than by age. By undertaking a half-life refurbishment on a power transformer we can increase its lifecycle, which is more beneficial economically than purchasing a new unit.

5.4.2 Online maintenance techniques

We use two portable oil monitoring/conditioning trailers, manufactured by Trojan, to monitor and remove excess moisture from our transformer oil. One trailer, with a Calisto 2 gas online DGA and moisture monitor will carry out analysis of the transformer oil moisture level. It monitors the hydrogen (H2) and Carbon Monoxide (CO) levels present in the oil. All zone substation power transformers are analysed over a two year period.

The second trailer has an inline oil filtration system and is used to target transformers with higher than desirable levels of moisture in their oil. We are also investigating other means of online testing.

5.4.3 Tap-changer Replacement/Maintenance

Annual tap-changer operations can be recorded via modern transformer management relays. A process is being developed to download this data for analysis. If any tap-changers appear to operate more frequently than others in the network an investigation can be undertaken to determine the cause. Switching under load also affects the amount of wear on tap-changer contacts so it is important we consider this whilst developing the maintenance regime.

Vacuum tap-changers require maintenance after 300,000 operations compared with 150,000 for oil. Since our rural transformers require more tap operations per annum, the older style oil tap changers on these units were replaced with vacuum tap-changers. This means that the frequency of maintenance on rural tap-changers can be extended.

5.5 REPLACEMENT PLAN

The condition of the transformer and its ability to provide reliable and safe service is the main driver for replacement. We will use the CBRM model to develop future refurbishment and replacement plans.

The capacity of a transformer is another driver for replacing it or relocating it to another part of the network. As local load requirements increases an assessment is carried out to determine if an existing transformer is sufficiently rated. If the load exceeds the N-1 capability of the zone substation the transformer will either be replaced by a bigger unit or undergo an upgrade to improve its forced cooling.

The location of the transformer in the network can have a significant effect on the loading of the unit. All units will be subjected to seasonal increases in load. The rural units have a higher summer load while the urban units have a higher winter load. Transformers installed at a dual-bank substation will rarely be required to operate continuously at their forced cooled rating.

5.6 DISPOSAL PLAN

While the age of a transformer can have a significant effect on the unit's performance and reliability, good asset management techniques enable us to extend the service life of our power transformers. However there are some cases where it is necessary to remove a unit from service before the optimum economic time.

The transformer BRU69923 at Springston zone substation has been targeted to be decommissioned in 2015. It is the only 7.5MVA unit that has a separate cooling tower which makes it unsuitable for swapping with other units in the network. It also has a Fuller tap-changer which is prone to failure and is costly to maintain. Springston zone substation will soon be converted to 66kV and it is more economically feasible to retire the unit at that stage than to carry out half-life maintenance and install a new vacuum tap-changer.

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.9 RISK ANALYSIS

A risk analysis of all power transformers was carried out to determine if any require attention. It has been identified that all the 20/40MVA Tyree units have an issue with the oil flow valve, also known as sugar bowls. The probability of these valves failing is 'quite possible' with the consequences of this failure classed as 'very serious'. As a result a process for remedial work has been initiated.

The 33/11kV transformers at Shands Rd zone substation also rate in the higher percentile on the risk matrix. It has been identified that the Tolley unit (T2) has a possible issue with its oil flow flap, which restricts the flow of oil thus causing the transformer to run hotter when under load. While this doesn't prevent the operation of the transformer during normal operating conditions it does restrict the amount of load we can subject it to during an N-1 event. An investigation into this issue will be undertaken in the near future.

The Ferranti transformer (T1) suffered a collapsed coil a number of years ago. Extensive repairs were undertaken and the unit was returned to service. While there have been no further failures of this magnitude on this unit the probability of such an event happening again has been classified as 'might well be expected'. As a result of this and the fact that T2 has limited capacity due to cooling issues the consequence of loosing either transformer has been classified as 'major'. At this stage there are no immediate plans to remove these transformers from service, however they will be monitored more closely that others in the network.

The 66/11kV spare transformers at Dunsandel and Barnett Park have a low probability of failing however the consequences are high if they are not readily available for relocation when required. The risks and consequences of failure for all the other power transformers in the network are deemed to be satisfactory thus no immediate action to replace them is required.

A "hot spare" is utilised for each transformer type. This allows the unit to be in service at all times and is easily swapped, should it be required, with similar units. The transformers are designed to be of a similar footprint meaning they can be interchanged with minimal onsite alterations.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 9 is a plot of the scheduled expenditure for our power transformers and shows both our historical spend and forecast budget.

Figure 9: Historical and Forecast Expenditure – Power Transformers Scheduled

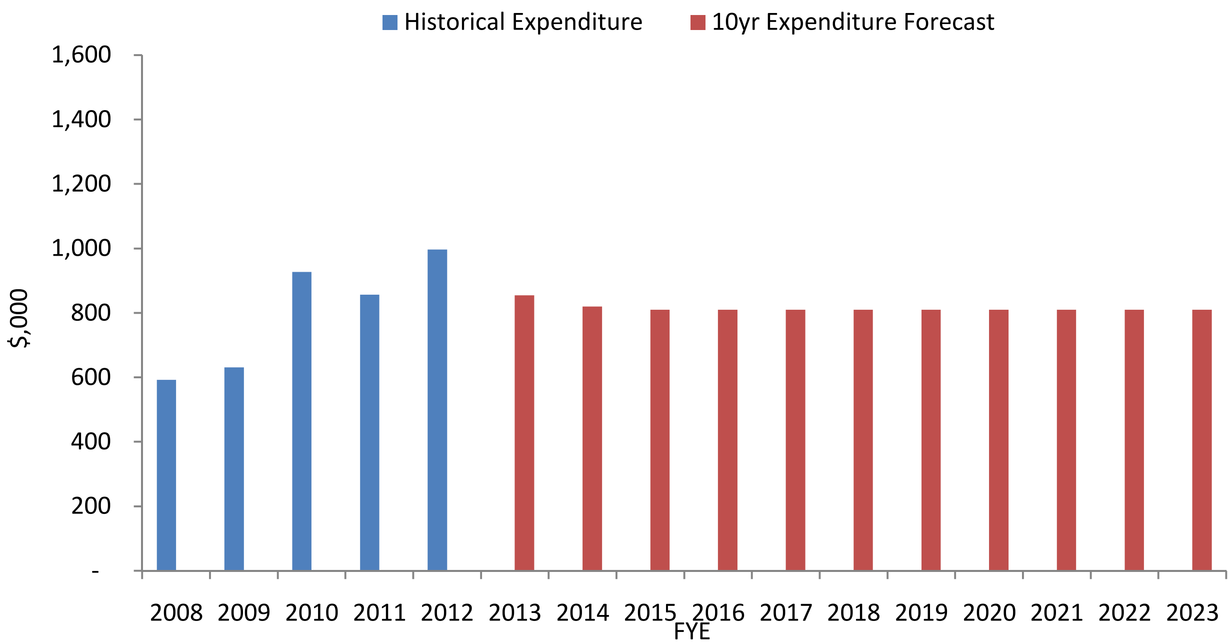


Figure 10: Historical Power Transformer Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	**592**	**631**	**918**	**856**	**997**	**855**
Non-Scheduled	93	86	170	58	167	100
Emergency	127	132	118	105	137	140

Note: The values shown for historical non-scheduled and emergency expenditure are for both power and distribution transformers.

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 11: Power Transformer Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	**820**	**810**	**810**	**810**	**810**	**810**	**810**	**810**	**810**	**810**
Non-Scheduled	*100*	*100*	*100*	*100*	*100*	*100*	*100*	*100*	*100*	*100*
Emergency	*190*	*190*	*225*	*190*	*190*	*190*	*190*	*190*	*190*	*190*

Note: The values shown for non-scheduled and emergency expenditure are for both power and distribution transformers.

Our scheduled maintenance for power transformers is carried out as part of the wider substation maintenance programme. These works are tendered out as part of our contract model. The budget allows for our half-life refurbishment programme and also our programme for maintaining the moisture levels of the oil.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency works contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

We haven't replaced any power transformers in the past 5 years and don't have any scheduled for replacement. Any new transformers will be purchased as part of a major project.

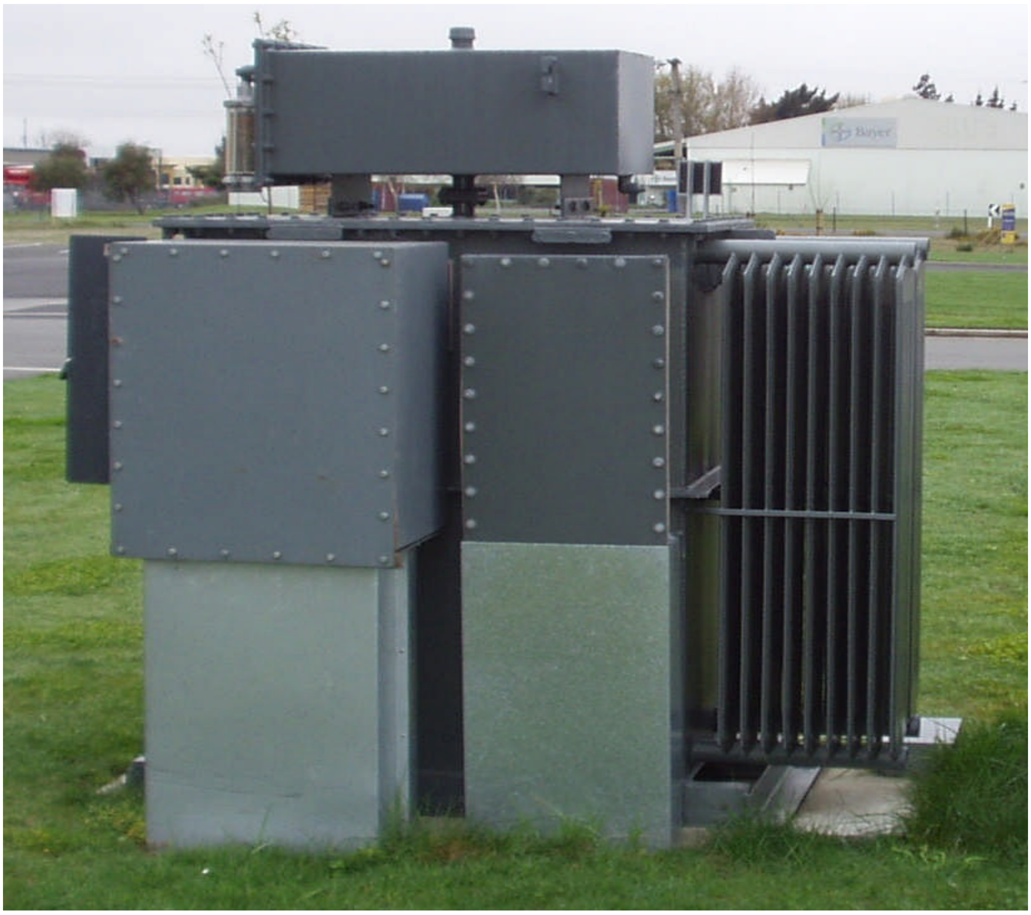
Appendix A

Power Transformer Condition Ranking

Asset ID	Substation	Site ID	Slot Name	PrimVolt	kVA	Ext kVA	Manufacturer	Health Index
TYR18626	TEDDINGTON ZONE SUB	HA8/38	TEDDINGTON ZONE SUB (T1)	33000	2500	0	TYREE	7
BRU69923	SPRINGSTON ZONE SUB	L8/155	SPRINGSTON ZONE SUB (T1)	33000	7500	0	BRUSH	6
TYR18625	ANNAT ZONE SUB	KO12/67	ANNAT ZONE SUB (T1)	33000	2500	0	TYREE	6
TYR12416	MOTUKARARA ZONE SUB	HA14/30	MOTUKARARA ZONE SUB (T1)	33000	2500	0	TYREE	6
BRU69919	BROOKSIDE ZONE SUB	L9/98	BROOKSIDE ZONE SUB (T2)	33000	7500	0	BRUSH	5
TYR16524	WEEDONS ZONE SUB	R15/174	WEEDONS ZONE SUB (T2)	33000	7500	0	TYREE	5
FER158188	DALLINGTON ZONE SUB	C147/104	DALLINGTON ZONE SUB (T2)	66000	20000	40000	FERRANTI	5
FER158185	OXFORD-TUAM ZONE SUB	C138/260	OXFORD-TUAM ZONE SUB (T2)	66000	20000	40000	FERRANTI	4
FER158187	DALLINGTON ZONE SUB	C147/104	DALLINGTON ZONE SUB (T1)	66000	20000	40000	FERRANTI	4
FER161401	MCFADDENS ZONE SUB	C127/149	MCFADDENS ZONE SUB (T1)	66000	20000	40000	FERRANTI	4
FER161402	MCFADDENS ZONE SUB	C127/149	MCFADDENS ZONE SUB (T2)	66000	20000	40000	FERRANTI	4
FER158182	HAWTHORNDEN ZONE SUB	C107/87	HAWTHORNDEN ZONE SUB (T1)	66000	20000	40000	FERRANTI	4
FER161405	BRIGHTON ZONE SUB	C157/110	BRIGHTON ZONE SUB (T1)	66000	20000	40000	FERRANTI	4
FER161406	BRIGHTON ZONE SUB	C157/110	BRIGHTON ZONE SUB (T2)	66000	20000	40000	FERRANTI	4
WIL34021	HORORATA ZONE SUB	HK13/23	HORORATA ZONE SUB (T1)	33000	7500	0	WILSON	4
FER161404	OXFORD-TUAM ZONE SUB	C138/260	OXFORD-TUAM ZONE SUB (T1)	66000	20000	40000	FERRANTI	4
FER160739	SHANDS RD ZONE SUB	C13/397	SHANDS RD ZONE SUB (T1)	33000	11500	23000	FERRANTI	4
WIL34785	HAREWOOD ZONE SUB	C5/31	HAREWOOD ZONE SUB (T2)	33000	7500	0	WILSON	3
TYR17846	HORNBY ZONE SUB	C13/94	HORNBY ZONE SUB (T1)	33000	10000	20000	TYREE	3
TOL30052	DUVAUCHELLE ZONE SUB	PB15/82	DUVAUCHELLE ZONE SUB (T2)	33000	7500	0	CANZAC	3
TYR18068	HORNBY ZONE SUB	C13/94	HORNBY ZONE SUB (T2)	33000	10000	20000	TYREE	3
TYR17845	SOCKBURN ZONE SUB	C10/611	SOCKBURN ZONE SUB (T2)	33000	10000	20000	TYREE	3
TYR18042	MILTON ZONE SUB	C131/7	MILTON ZONE SUB (T2)	66000	20000	40000	TYREE	2
TYR18043	MILTON ZONE SUB	C131/7	MILTON ZONE SUB (T1)	66000	20000	40000	TYREE	2
TYR18044	FENDALTON ZONE SUB	C118/33	FENDALTON ZONE SUB (T2)	66000	20000	40000	TYREE	2
TYR18045	FENDALTON ZONE SUB	C118/33	FENDALTON ZONE SUB (T1)	66000	20000	40000	TYREE	2
TOL33774	DUVAUCHELLE ZONE SUB	PB15/82	DUVAUCHELLE ZONE SUB (T1)	33000	7500	0	CANZAC	2
TYR18437	HEATHCOTE ZONE SUB	C151/39	HEATHCOTE ZONE SUB (T2)	66000	20000	40000	TYREE	2
TYR18318	ARMAGH ZONE SUB	C138/432	ARMAGH ZONE SUB (T2)	66000	20000	40000	TYREE	2
TYR18317	ARMAGH ZONE SUB	C138/432	ARMAGH ZONE SUB (T1)	66000	20000	40000	TYREE	2
FER158184	HEATHCOTE ZONE SUB	C151/39	HEATHCOTE ZONE SUB (T1)	66000	20000	40000	FERRANTI	2
FER158183	HAWTHORNDEN ZONE SUB	C107/87	HAWTHORNDEN ZONE SUB (T2)	66000	20000	40000	FERRANTI	2
TOL38679	MOFFETT ST ZONE SUB	C9/162	MOFFETT ST ZONE SUB (T2)	33000	11500	23000	CANZAC	2
TOL38680	MOFFETT ST ZONE SUB	C9/162	MOFFETT ST ZONE SUB (T1)	33000	11500	23000	CANZAC	2
TYR18067	SOCKBURN ZONE SUB	C10/611	SOCKBURN ZONE SUB (T3)	33000	10000	20000	TYREE	2
TYR18434	PREBBLETON ZONE SUB	HA1/279	PREBBLETON ZONE SUB (T2)	33000	11500	23000	TYREE	2
OEL5579	LINCOLN ZONE SUB	HA5/192	LINCOLN ZONE SUB (T1)	33000	7500	0	OEL	2
PAU01-P-0002	TE PIRITA ZONE SUB	HL6/17	TE PIRITA ZONE SUB (T1)	66000	7500	10000	PAUWELS	2
FER158186	HOON HAY ZONE SUB	C121/87	HOON HAY ZONE SUB (T1)	66000	20000	40000	FERRANTI	2
FER158189	HOON HAY ZONE SUB	C121/87	HOON HAY ZONE SUB (T2)	66000	20000	40000	FERRANTI	2
TOL38681	SHANDS RD ZONE SUB	C13/397	SHANDS RD ZONE SUB (T2)	33000	11500	23000	ASTEC	2
OEL5578	DARFIELD ZONE SUB	HK10/48	DARFIELD ZONE SUB (T1)	33000	7500	0	OEL	2
BRU72619	SOCKBURN ZONE SUB	C10/611	SOCKBURN ZONE SUB (T1)	33000	11500	23000	BRUSH	1
OEL5577	LINCOLN ZONE SUB	HA5/192	LINCOLN ZONE SUB (T2)	33000	7500	0	OEL	1
BRU69920	HAREWOOD ZONE SUB	C5/31	HAREWOOD ZONE SUB (T1)	33000	7500	0	BRUSH	1
TOL10394	ROLLESTON ZONE SUB	L3/133	ROLLESTON ZONE SUB (T2)	33000	7500	0	CANZAC	1
OEL5576	HILLS RD ZONE SUB	SO1/24	HILLS RD ZONE SUB (T1)	33000	7500	0	OEL	1
GEC33K7823-1	LITTLE RIVER ZONE SUB	PB13/66	LITTLE RIVER ZONE SUB (T1)	33000	2500	0	GEC	1
PAU04-P-0058	GREENDALE ZONE SUB	SE2/66	GREENDALE ZONE SUB (T1)	66000	7500	10000	PAUWELS	1
ABB1341101	BANKSIDE ZONE SUB	SE6/33	BANKSIDE ZONE SUB (T1)	33000	7500	10000	ABB	1
WIL39554	HIGHFIELD ZONE SUB	R13/51	HIGHFIELD ZONE SUB (T1)	33000	7500	0	WILSON	1
TOL10393	ROLLESTON ZONE SUB	L3/133	ROLLESTON ZONE SUB (T1)	33000	7500	0	CANZAC	1
PAU00-P-0045	KILLINCHY ZONE SUB	SE12/53	KILLINCHY ZONE SUB (T1)	66000	7500	10000	PAUWELS	1
PAU99-P-0038	LANCASTER ZONE SUB	C138/436	LANCASTER ZONE SUB (T2)	66000	20000	40000	PAUWELS	1
PAU99-P-0039	LANCASTER ZONE SUB	C138/436	LANCASTER ZONE SUB (T1)	66000	20000	40000	PAUWELS	1
PAU06-P-0088	MIDDLETON ZONE SUB	C10/612	MIDDLETON ZONE SUB (T1)	66000	20000	40000	PAUWELS	1
PAU07-P-0055	DUNSANDEL ZONE SUB	SE11/89	DUNSANDEL ZONE SUB (T2)	66000	7500	10000	PAUWELS	1
PAU03-P-0050	HAWTHORNDEN ZONE SUB	C107/87	HAWTHORNDEN ZONE SUB (T4)	66000	11500	23000	PAUWELS	1
PAU03-P-0051	HAWTHORNDEN ZONE SUB	C107/87	HAWTHORNDEN ZONE SUB (T3)	66000	11500	23000	PAUWELS	1
PAU03-P-0052	HALSWELL ZONE SUB	C111/56	HALSWELL ZONE SUB (T2)	66000	11500	23000	PAUWELS	1
PAU03-P-0053	HALSWELL ZONE SUB	C111/56	HALSWELL ZONE SUB (T1)	66000	11500	23000	PAUWELS	1
PAU04-P-0057	DUNSANDEL ZONE SUB	SE11/89	DUNSANDEL ZONE SUB (T1)	66000	7500	10000	PAUWELS	1
PAU06-P-0031	MOTUKARARA ZONE SUB	HA14/30	MOTUKARARA ZONE SUB (T2)	33000	7500	0	PAUWELS	1
PAU03-P-0070	BROOKSIDE ZONE SUB	L9/98	BROOKSIDE ZONE SUB (T1)	66000	7500	10000	PAUWELS	1
PAU05-P-0038	BARNETT PARK ZONE SUB	C161/28	BARNETT PARK ZONE SUB (T2)	66000	11500	23000	PAUWELS	1
PAU05-P-0039	LARCOMB ZONE SUB	R15/258	LARCOMB ZONE SUB (T1)	33000	11500	23000	PAUWELS	1
PAU06-P-0089	MIDDLETON ZONE SUB	C10/612	MIDDLETON ZONE SUB (T2)	66000	20000	40000	PAUWELS	1
PAU06-P-0030	DIAMOND HARBOUR ZONE SUB	PB4/31	DIAMOND HARBOUR ZONE SUB (T1)	33000	7500	0	PAUWELS	1

Distribution Transformers

Asset Management Report YE 2012



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1 INTRODUCTION

Distribution transformers are installed throughout Orion's network to transform the 11kV distribution voltage down to 400V for consumer connections.

This document covers each of our distribution transformer categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these transformers.

2 ASSET DESCRIPTION

2.1 GENERAL

Distribution transformers are installed on our network to transform voltage to a suitable level for consumer connections. They have a ratio of 11000/400V, and range in capacity from 5kVA to 1,500kVA.

Sizes up to 200kVA can be installed on a single pole. The larger sizes are only ground-mounted, either outdoors or inside a building.

Figure 1: Distribution Transformers In-service

kVA Rating	Quantity	Avg Fin Year	Avg Age (Yrs)
5	59	1965	47
7.5	302	1964	48
10	187	1967	45
15	1,449	1988	24
20	5	1966	46
25	365	1972	40
30	1,904	1996	16
50	1,140	1988	24
75	169	2003	9
100	692	1990	22
125	1	1950	62
150	150	2004	8
200	1,508	1980	32
250	7	1964	48
300	1,626	1983	29
333(1ph)	18	1948	64
400	12	1968	44
500	743	1991	21
600	1	1965	47
750	267	1987	25
1000	135	1993	19
1250	3	1997	15
1500	9	1999	13
Total	**10,752**	**1987**	**25**

2.2 ASSET TYPES

We have a number of different configurations of distribution transformers. Figure 2 below details the coding used for describing these assets and Figure 3 shows the numbers of each different type.

Figure 2: Distribution Transformer - Configuration Type Codes

Location Suitability	Transformer type	Terminations	HV Connection	LV Connection
B – building subs	S – standard	S – same side	C – cable box	C – cable box
H – high kiosk	C – conservator fitted	X – opposite	B - bushing	B - bushing
L – low kiosk	B – berm			
O – outdoor sub	E – earth return			
P – pole sub				

Figure 3: Distribution Transformer - Types

Wasp Code	Quantity	Suitability	Transformer Type	Terminations	HV Connection	LV Connection
BCSCC	18	Building sub	Conservator	Same side	Cable box	Cable box
BCXCC	7	Building sub	Conservator	Crossed	Cable box	Cable box
BSSCC	51	Building sub	Standard	Same side	Cable box	Cable box
BSXBB	9	Building sub	Standard	Crossed	Bushing	Bushing
BSXBC	1	Building sub	Standard	Crossed	Bushing	Cable box
BSXCB	7	Building sub	Standard	Crossed	Cable box	Bushing
BSXCC	19	High kiosk	Standard	Crossed	Cable box	Cable box
HSSBB	1	High kiosk	Standard	Same side	Bushing	Bushing
HSXBB	38	High kiosk	Standard	Crossed	Bushing	Bushing
HSXCB	3	High kiosk	Standard	Crossed	Cable box	Bushing
HSXCC	6	High kiosk	Standard	Crossed	Cable box	Cable box
HTXCB	1	High kiosk		Crossed	Cable box	Bushing
LSSBB	29	Low kiosk	Standard	Same side	Bushing	Bushing
LSSCB	19	Low kiosk	Standard	Same side	Cable box	Bushing
LSSCC	1250	Low kiosk	Standard	Same side	Cable box	Cable box
LSXBB	74	Low kiosk	Standard	Crossed	Bushing	Bushing
LSXCB	69	Low kiosk	Standard	Crossed	Cable box	Bushing
LSXCC	9	Low kiosk	Standard	Crossed	Cable box	Cable box
OCSCC	12	Outdoor sub	Conservator	Same side	Cable box	Cable box
OCXCC	9	Outdoor sub	Conservator	Crossed	Cable box	Cable box
OSSCC	122	Outdoor sub	Standard	Same side	Cable box	Cable box
OSXCC	28	Outdoor sub	Standard	Crossed	Cable box	Cable box

PSXBB	5368	Pole sub	Standard	Crossed	Bushing	Bushing
BERM	40	Berm sub				
BLDG	242	Building (unspecified)				
GRMU	33	Ground mounted (unspecified)				
HIKI	69	High kiosk (unspecified)				
INDO	22	Indoor (unspecified)				
KISK	4	Kiosk (unspecified)				
LOKI	267	Low kiosk (unspecified)				
MICRO	220	Pad mount micro				
MINI	4	Pad mount mini				
SWER	10	Earth return				
UNKN	3156	Unknown				

There are transformers from 23 different manufacturers on our network. Currently ABB is the preferred supplier.

Figure 4: Transformer Manufacturers

Manufacturer	Manuf Code	Number of Tx
Asea Brown Boveri	ABB	4,282
ASEA	ASE	7
Astec	AST	300
Aus Std Elec	AUT	7
Bonar Long	BON	33
British Power	BPC	2
British Thompson	BTH	1
Bruce Peebles	BPE	22
Brush	BRU	1
Crompton Parkinson	C-P	33
ECC	ECC	160
Elec & Tran Eng	ETE	324
Ferranti	FER	33
GEC	GEC	4
Heckbridge	HEC	1
Joy	JOY	37
Metro-Vickers	M-V	54
Power Construction	PCO	524
Schneider	SCH	1
Turnbull & Jones	T&J	1,911
Tolley	TOL	1,838
Tyree	TYR	1,142
Walker	WAL	35
Total		**10752**

2.2.1 Outdoor Substation Transformers

The transformers are manufactured with a number of different cable box configurations to suit the various installation requirements. They range in size from 15kVA to 1500kVA.

2.2.2 Low Style Full Kiosk Transformers

Due to size constraints the maximum rating of a transformer installed in a low kiosk is 500kVA. These are low type with cable boxes/bushings mostly on the same side.

2.2.3 Pole Transformers

Pole mounted transformers range in rating from 15kVA – 300kVA. The policy for new installations is to mount transformers no bigger than 200kVA. The only 200kVA transformers suitable for pole mounting are a specific variant purchased especially for pole mounting.

3 ASSET PERFORMANCE

Transformer utilisation is measured as the ratio of maximum demand in kVA to installed nameplate rating. For individual transformers, this ratio typically ranges from below 30% to above 130%.

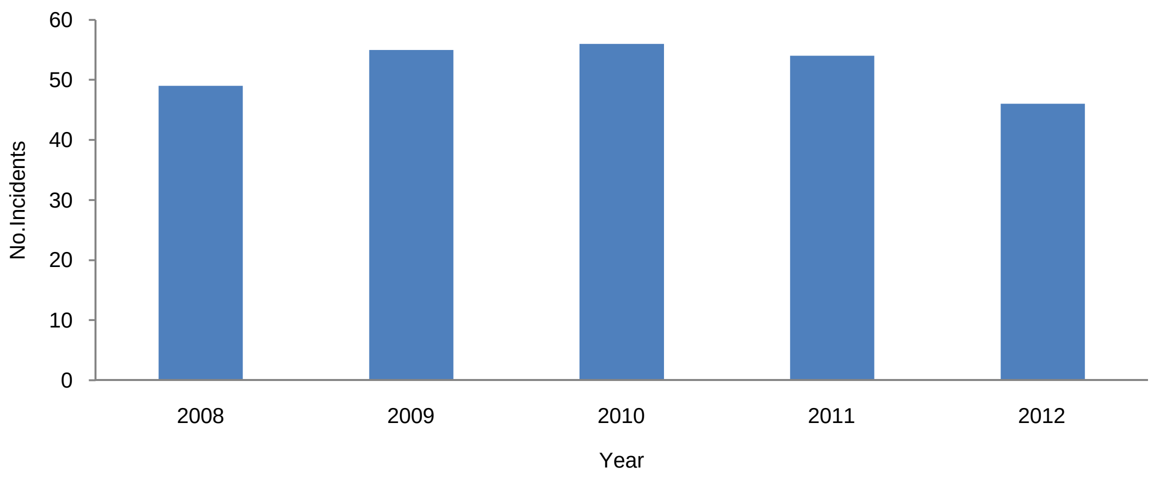
The measure of overall distribution transformer utilisation required for disclosure is the ratio of the total system demand to total distribution transformer capacity. This has fallen slowly over the last 20 years to its present value of approximately 35%.

Small pole-mounted transformers usually serve only a small number of consumers. Capacities are normally only reviewed when significant new load is connected. Utilisation factors are typically low, with overall values in rural areas of around 30%.

Larger transformers are fitted with thermal maximum-demand meters which are read twice-yearly. Measured utilisation factors range up to about 140%. For typical cyclic loads, we have determined that maximum demands of about 130% of rated continuous ratings are acceptable, before upgrading action is required.

When distribution transformer maximum demand exceeds 130% of nameplate rating, a larger transformer is installed or load transferred to another substation if available. Where substation utilisation is low (<50% with no load growth predicted), the transformer will be changed or removed when this is economically justified.

Figure 5: Distribution Transformer Performance



4 ASSET CONDITION

4.1 GENERAL

Our larger ground mounted distribution transformers are in good condition and are inspected on site every six months. The condition of the pole mounted transformers varies depending on their age and location. They are only maintained, if this is considered appropriate, when removed from service for other reasons.

There are approximately 15 single-phase banks of transformers over 50 years of age. Manufactured between 1937 and 1950, they have iron losses that are four to six times; and copper losses that are two to three times that of a modern transformer. Most have high oil acidity, indicating that they are nearing the end of their lives.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our distribution transformers. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual transformer. This effectively gives the transformer a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Figure 6: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 7: Year 0 Health Index Profile – Ground Mounted

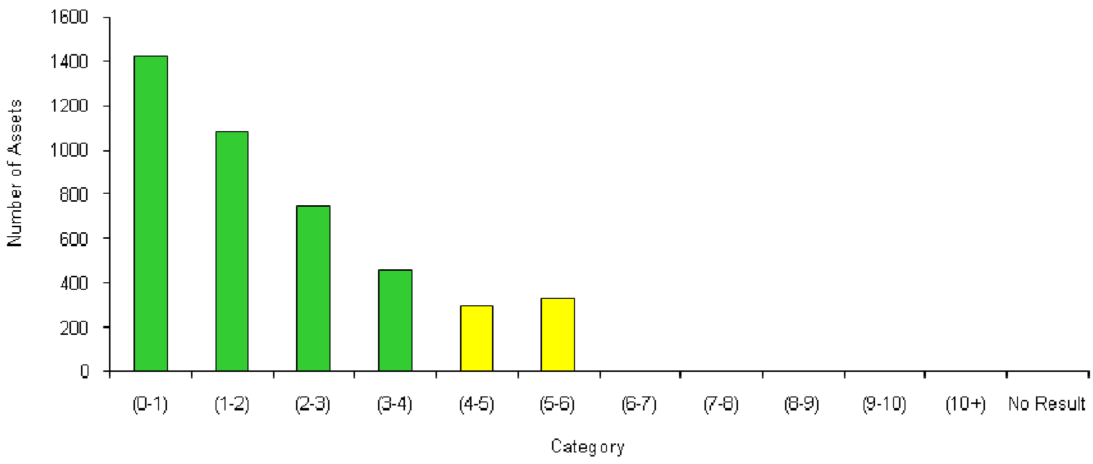
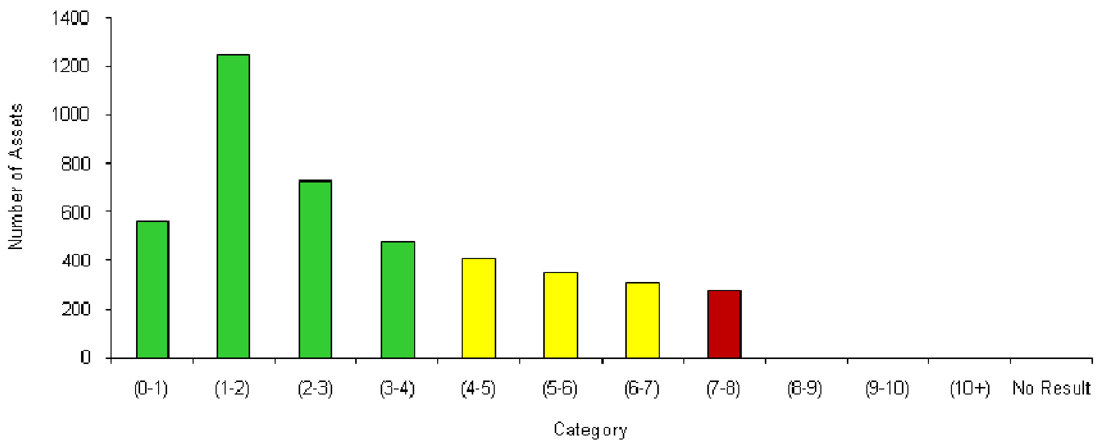


Figure 8: Year 10 Health Index Profile – Ground Mounted



Figures 8 and 11 show the current condition of our distribution transformer population. Figures 9 and 12 show the condition of our distribution transformer population in 10 years time if no further investment is made in the replacement programme.

Figure 9: Year 10 – % Replacement Health Index Profile – Ground Mounted

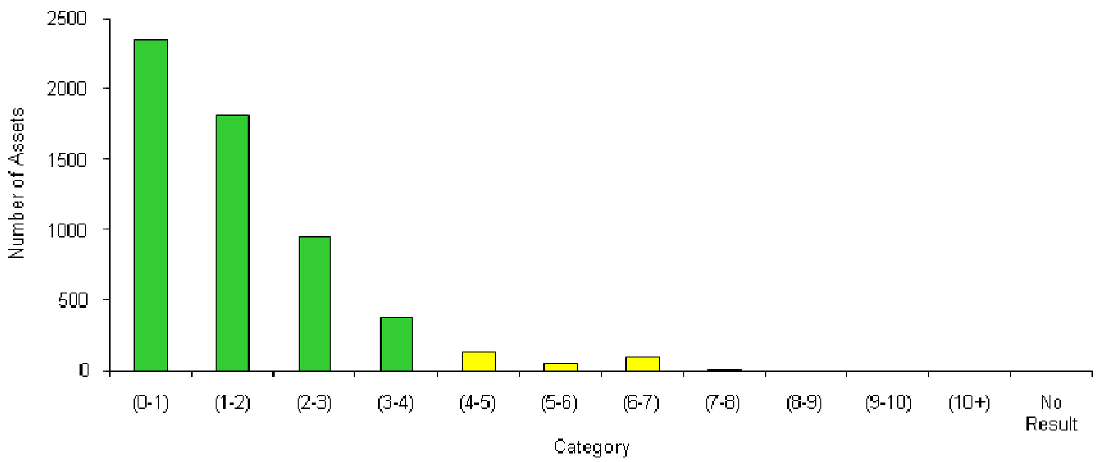


Figure 9 illustrates the year 10 condition profile if a replacement rate of 1.5% is adopted. This rate enables us to maintain our current profile. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

However the year 0 plot shows the overall condition of our ground mounted transformer switchgears is good and we are on target with our replacement programme.

Figure 10: Year 0 Health Index Profile – Pole Mounted

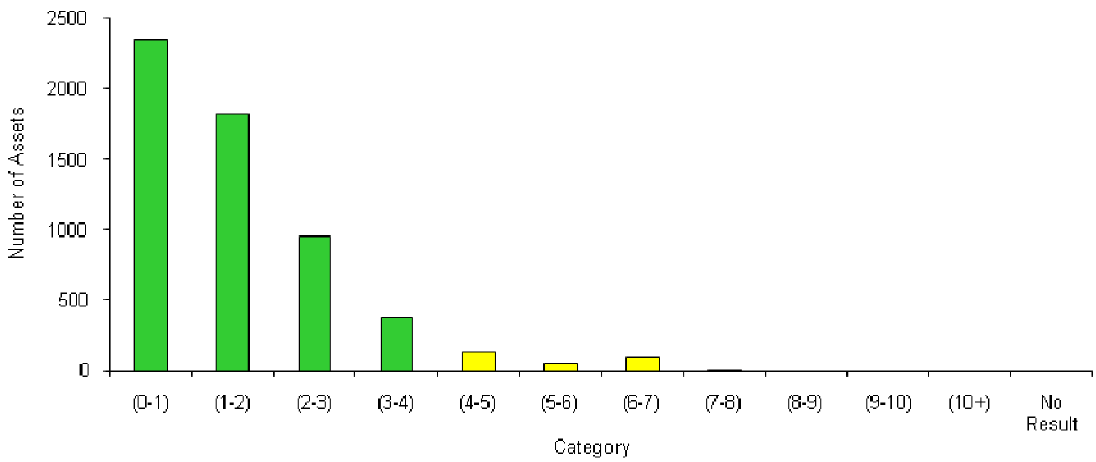


Figure 11: Year 10 Health Index Profile – Pole Mounted

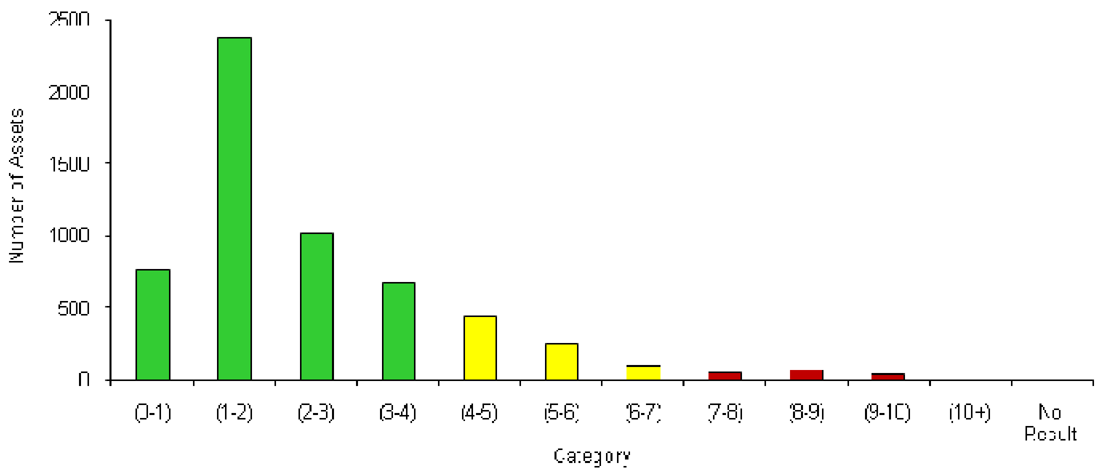


Figure 12: Year 10 – % Replacement Health Index Profile – Pole Mounted

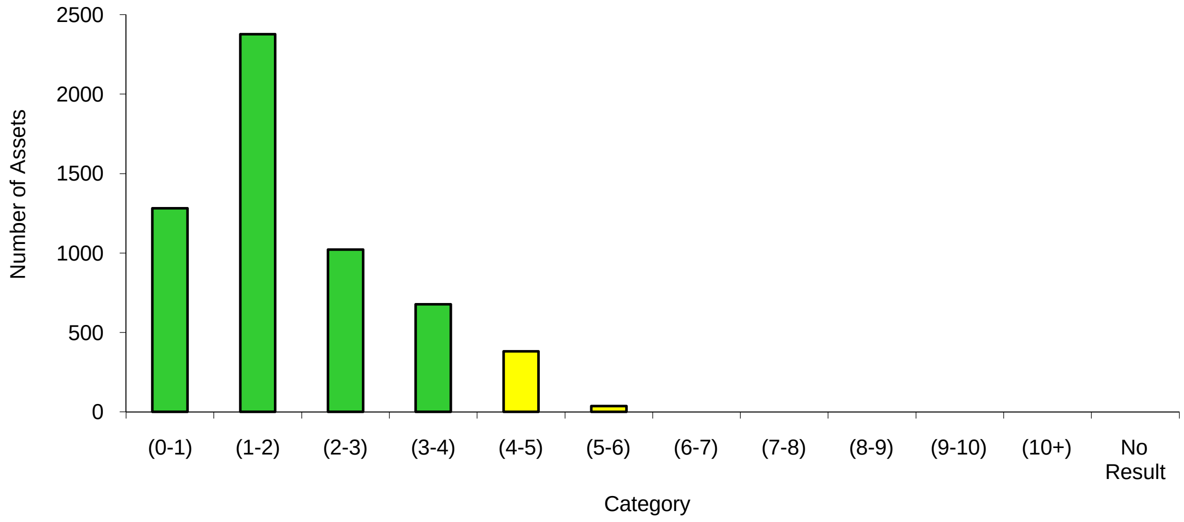


Figure 12 illustrates the year 10 condition profile if a replacement rate of 0.9% is adopted. This rate enables us to maintain our current profile. The CBRM model also enables us to plot a targeted replacement programme. At the time of writing we are in the process of updating the models with our latest asset data and as a result the targeted intervention portion has not yet been implemented.

However the year 0 plot shows the overall condition of our pole mounted transformers is acceptable and we are on target with our replacement programme.

4.3 HISTORICAL ISSUES

In the past a number of transformers have been identified with high levels of acidity which have caused severe corrosion to the tank lid.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

We employ a number of different asset management practices for different asset groups. Refer to *NW72.23.02* for more information.

5.2 DISTRIBUTION TRANSFORMERS LIFECYCLE

We assign a nominal service life of 60 years to a distribution transformer.

Figure 13: Age Profile Distribution Transformers (Pole)

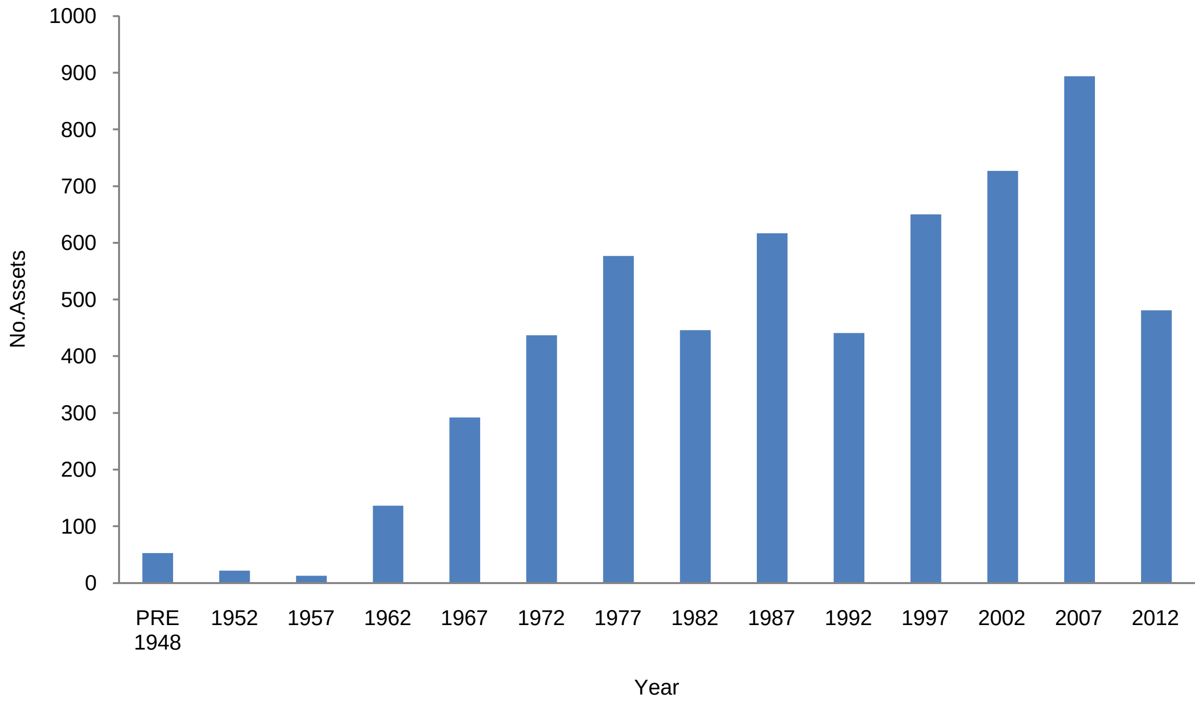
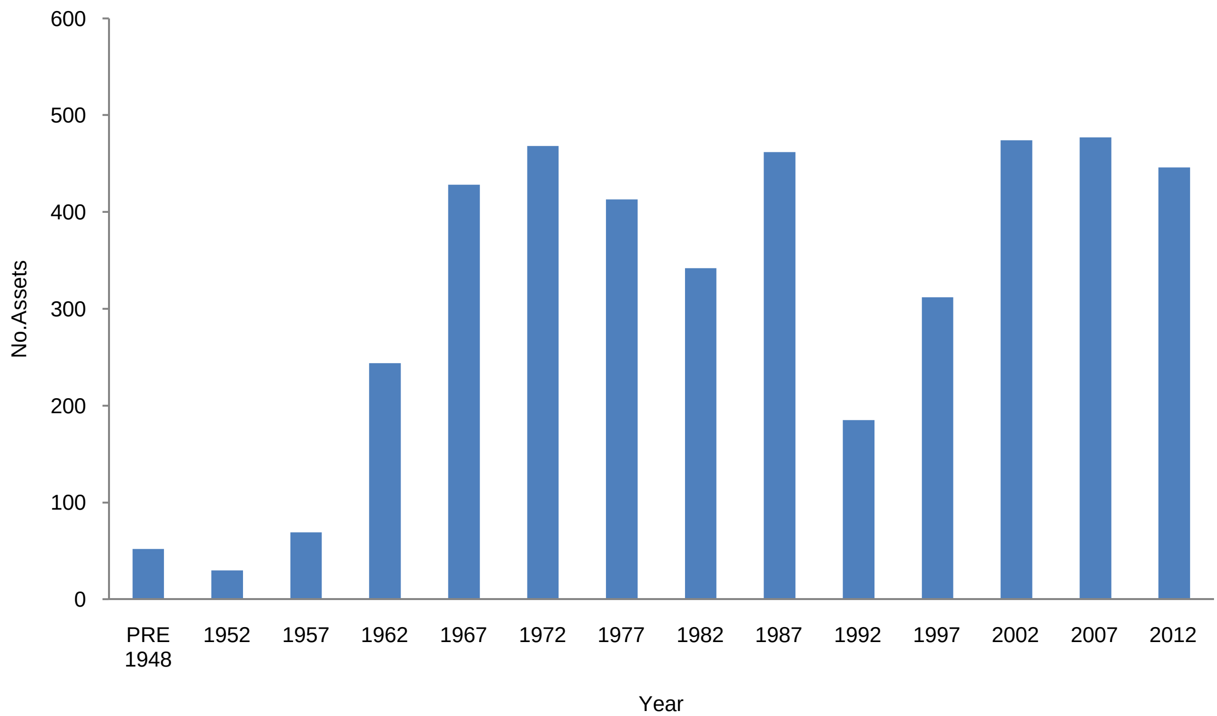


Figure 14: Age Profile Distribution Transformers (Ground Mounted)



5.3 MAINTENANCE PLAN

With the exception of the transformers in network substations, distribution transformers are normally maintained when they are removed from service for loading reasons or because of maintenance work. Their condition at that stage is assessed on a lifetime costs basis and we decide, prior to any maintenance, whether it would be more economic to replace them. If we decide to maintain them they will be improved to a state where it can be expected the transformer will give at least another 15 to 20 year's service without maintenance.

Some on-site maintenance is carried out on transformers which are readily accessible from the ground. This work mainly relates to distribution transformers within building substations that require maintenance as identified during maintenance inspection programmes.

Remaining single-phase transformer banks are to receive minimal maintenance to extend their usable life until replaced.

Maintenance Standards

NW72.23.02	Transformer Maintenance (Distribution)
NW72.23.01	Specification for Mineral Insulating Oil

5.4 REPLACEMENT PLAN

The condition of a transformer and its ability to provide reliable and safe service is the main driver for replacement. We will refine our CBRM model for this asset group over the next year and then use it to drive the replacement plan.

The capacity of a transformer is another driver for replacing it or relocating it to another part of the network. As local load requirements increase an assessment is carried out to determine if an existing transformer is sufficiently rated. If the load exceeds the rating of the transformer an assessment will be made as to whether replacement is required.

The location of the transformer in the network can have a significant effect on the loading of the unit. All units will be subjected to seasonal increases in load. The rural units have a higher summer load while the urban units have a higher winter load.

A programme is in place to replace existing single phase units in building substations with new three phase units. This is usually carried out in conjunction with other work at the site.

5.5 DISPOSAL PLAN

We dispose of transformers when they reach the end of their economic life, as detailed in the maintenance plan. Refer to NW72.23.02 Transformer Maintenance (Distribution).

5.6 CREATION / ACQUISITION PLAN

The procurement of distribution transformers is through a period supply contract arrangement. This was previously with ABB but is currently up for renewal. Transformers with a rating above 1000kVA are bought off the shelf from the supplier and have a crossbar (OSXCC) configuration.

Procurement Standards

NW74.23.05	Transformer – Ground Mounted Distribution 200 to 1000kVA

Figure 15: Transformer Impedances

kVA	200 – 300	500	750	>1000
Impedance	3% - 4.5%	3.5% - 5%	4% - 5%	4.5% - 5.5%

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.9 RISK ANALYSIS

Risk analysis of distribution transformers is carried out on a case by case basis.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 16: Scheduled Historical and Forecast Expenditure – Distribution Transformers

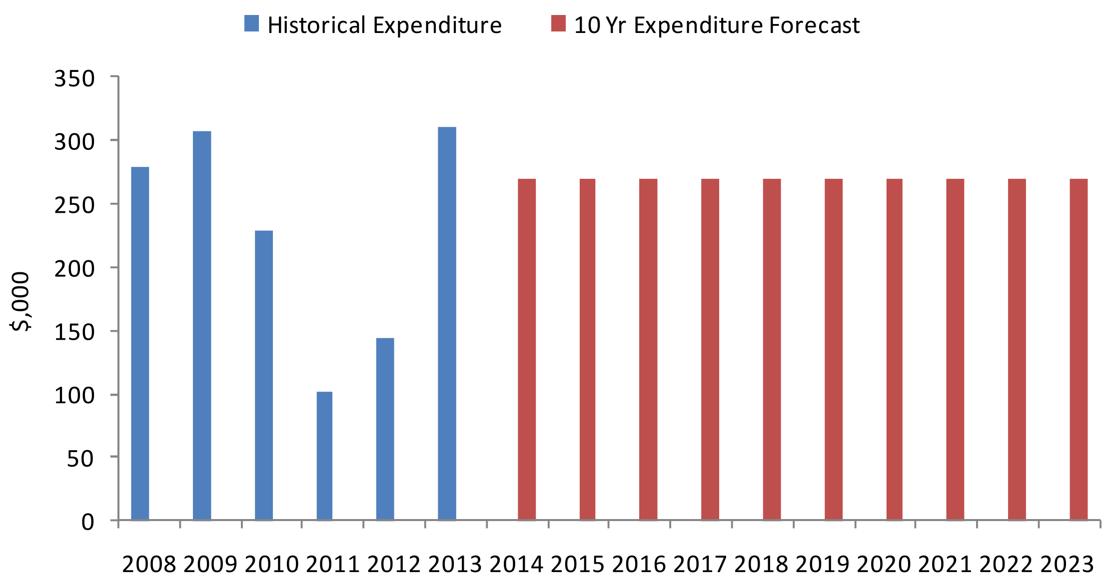


Figure 17: Historical Distribution Transformer Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	279	308	229	101	144	310

At the time of writing, the budgeted rather than actual expenditure figures were used.

Note: The values shown for historical non-scheduled and emergency expenditure are for both zone and distribution transformers. We do not distinguish between the two asset classes for these expenditure categories.

Figure 18: Distribution Transformer Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**

Note: The values shown for non-scheduled and emergency expenditure are for both zone and distribution transformers. We do not distinguish between the two asset classes for these expenditure categories.

Our scheduled maintenance is carried out in line with our contracting model where all works are tendered.

Our non-scheduled maintenance forecast is for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that requires our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 19: Historical and Forecast Expenditure – Distribution Transformers

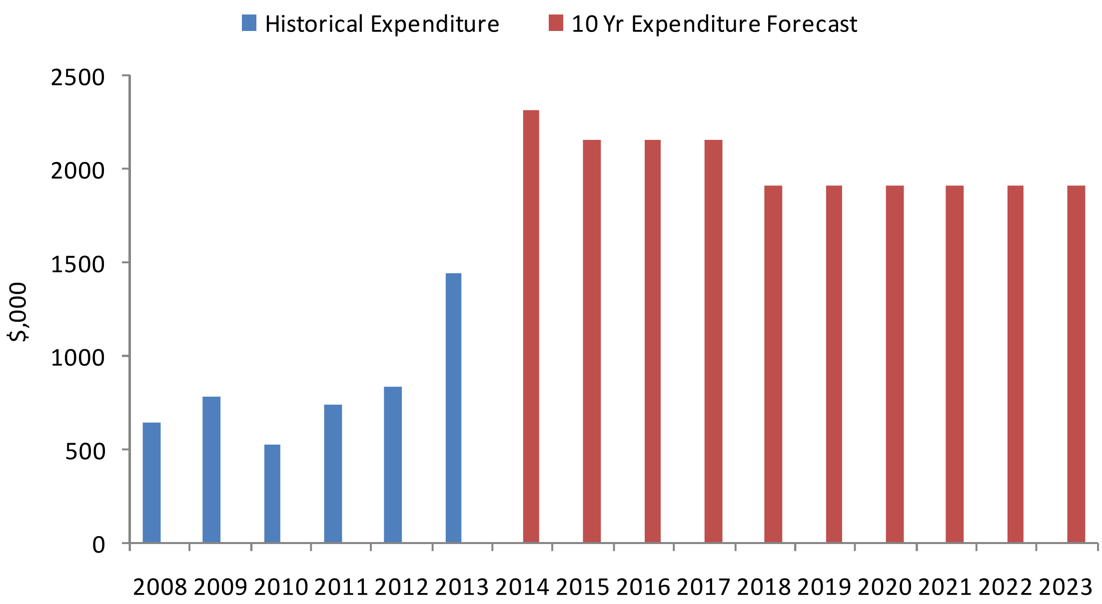


Figure 20: Historical Distribution Transformer Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	643	790	459	739	722	1445
Total	**643**	**790**	**459**	**739**	**722**	**1445**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

Figure 21: Distribution Transformer Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	2320	2160	2160	2160	1910	1910	1910	1910	1910	1910
Total	**2320**	**2160**	**2160**	**2160**	**1910**	**1910**	**1910**	**1910**	**1910**	**1910**

Our replacement expenditure based on a number of factors such as age, reliability, condition and safety. We are currently refining our CBRM model which will become our main driver for our replacement plan.

11kV Overhead Lines

Asset Management Report YE 2012

NW70.00.27

Table of Contents

1 INTRODUCTION

This document details the criteria and asset management practices used to ensure Orion obtains effective performance and acceptable service life from its 11kV overhead lines.

A survey to assess asset condition is carried out every five years to identify any maintenance or replacements required.

2 ASSET DESCRIPTION

2.1 GENERAL

Orion's 11kV overhead distribution system is 3,237km circuit length of lines mostly in the rural area of central Canterbury, between the Waimakariri and Rakaia rivers, from the Canterbury coast to Arthur's Pass and includes the outer areas of Christchurch city. Supply is taken from a number of zone substations as feeder lines which form a network to supply distribution transformers which feed 400V/230V to consumers. Supply is also taken directly at 11kV from GXPs at Coleridge, Castle Hill and Arthur's Pass.

These lines are built using approximately 51,000 timber and concrete poles with various conductor types as shown in Figures 1 and 2. Some of the poles also support subtransmission and/or low voltage circuits. Lines built on private property that supply individual consumers make up 32% of the total length.

Ten separate systems of single wire earth return (SWER) lines on Banks Peninsula total 103km circuit length. These lines supply power to remote areas, and as such can be exposed to severe weather conditions.

Figure 1: 11kV Poles

Pole Type	SDC	CCC	Total
CONCRETE	**15525**	**3381**	**18906**
A	906	685	1591
B	1		1
CON	3		3
PCAST	14597	2614	17211
PSTRE	14	80	94
T	4	1	5
TX		1	1
HARDWOOD	**8989**	**4806**	**13795**
SOFTWOOD	**11948**	**3356**	**15304**
LARCH	422	383	805
SW	11526	2973	14499
Total	**36462**	**11543**	**48005**

Figure 2: 11kV Overhead Conductors

Conductor Type	Length (m)	Avg Install Year	Avg Age (Yr)
19/.064Cu	109,493	1973	39
19/.083Cu	61,161	1982	30
19/.101Cu	6,285	1997	16
19/.152AL	28,342	1977	35
19/.183AL	796	1976	37
19/.163Cu (XLPE)	2,199	1991	21
19/.092Cu	11,207	1983	29
37/.108AL	4,445	1984	28
7/.064Cu	340,625	1978	34
7/.083Cu	56,837	1984	28
Dog	858,814	1987	25
Flounder	600,624	1998	14
Garnet (PVC Covered)	3,330	1975	37
Hake	8,678	1982	30
Herring	11,934	1990	22
Magpie	1,921	1972	40
Mata	1,501	1983	29
Mink	293,624	1980	32
Raven	23,885	1974	38
SC/AC (WOLF CORE) 7/2.59	928	2011	1
Sparrow	36,722	1984	28
Squirrel	641,754	1983	29
Swan	42,279	1984	28
Thrush	41,002	1987	25
Wolf	1,813	2009	3
Unknown	58,785	1995	17
Total	**3,248,983**	**1985**	**27**

2.2 ASSET TYPES

Orion's 11kV overhead lines are made up of various combinations of asset types and materials. Refer to: Figure 3 for information relating to pole type treatment and Figures 14-17 regarding age profile. For other materials e.g. crossarms and insulators refer to Orion's Overhead Lines Standard Construction Drawing Set: NW 72.21.18.

Figure 3: 11kV Poles (Type and Treatment by Length)

Pole Type	8.5m	9m	9.5m	10m	10.5m	11m	12m	12.5m	13m	14m	15m	15.5m	17m	21.5m	Total
Concrete	**7**	**112**	**17923**	**123**	**734**	**1**						**1**	**1**	**4**	**18906**
Hardwood	**25**	**128**	**7449**	**1656**	**105**	**3529**	**560**	**85**	**15**	**82**	**22**	**125**	**14**		**13795**
CCA	1	4	2065	1130	20	2650	491	43	9	71	13	75	12		6584
None	24	124	5384	526	85	879	69	42	6	11	9	50	2		7211
Softwood	**8**	**271**	**9598**	**2990**	**17**	**2108**	**268**	**21**	**1**	**20**	**2**				**15304**
CCA	4	201	8427	2975	15	2076	268	16	1	20	2				14005
CREOSOTE	1	32	734	7	2	24		5							805
S25	3	38	437	8		8									494
Total	**40**	**511**	**34970**	**4769**	**856**	**5638**	**828**	**106**	**16**	**102**		**126**	**15**	**4**	**48005**

3 ASSET PERFORMANCE

3.1 CAPACITY

3.1.1 Thermal Ratings

Orion's 11kV overhead network is comprised of various construction types depending on the application. Each variation has a different thermal capacity and hence ampacity ratings. The various overhead construction types found on Orion's network are outlined below with the corresponding maximum thermal ratings at the prescribed maximum design temperatures. It must be noted that the thermal ratings correspond to sag minimum clearances at maximum design temperatures, but these ratings are not necessarily the constraining factor on circuit capacities that can be limited by voltage drop, especially on the 11kV network, so the usable capacity may be less than the values stated.

All the line ratings shown in Figures 4-6 have been calculated using the IEEE 738-1993 standard as guidance. Climatic records for the Canterbury Plains were used to establish the thermal rating parameters, please refer to Appendix A for further details on the method of calculation.

3.1.2 Pole Lines

All existing service, spur and distribution lines have a maximum design temperature of 50degC. These ratings are independent of the ambient air temperature whereby the 50degC temperature is an absolute number, not a temperature rise over ambient.

Figure 4: 11kV Conductors - Existing

Conductor Type	Thermal Rating (Amps)
AAC	
Butterfly	513
Mata	398
AAAC	
Garnet (covered)	184
ACSR	
Dog	262
Ferret	150
Flounder	99
Hake	195
Herring	73
Jaguar	395
Magpie	69
Mink	193
Raven	173
Sparrow	130
Squirrel	91
Swan	98
Thrush	84
Wolf	337
Copper (Hard Drawn)	
7/.064	94
7/.083	133
19/.064	181
7/.136	245
19/.083	249
19/.092	283
19/.101	317
37/.083	375

All new service and spur lines have a maximum design temperature of 50degC and all new distribution feeders have a maximum design temperature of 70degC. The standard conductor types and maximum thermal ratings are shown in Figure 5.

Figure 5: 11kV Conductors - New

Conductor Type	Thermal Rating (Amps) 50degC	Thermal Rating (Amps) 70decC
ACSR		
Dog	262	355
Flounder	99	
Jaguar		559
Wolf		474

3.1.3 Tower Line Feeders

There is a single 11kV circuit operating on a 66kV construction light-weight tower. The maximum design temperature of this line is 60degC.

Figure 6: Thermal Rating

Conductor Type	Thermal Rating (Amps)
ACSR	
Wolf	424

3.2 PERFORMANCE

The overhead network has withstood several snow storms over the last six years and has performed very well. The major cause of damage was trees bringing down lines rather than deficiencies in design or installation. The robustness can in some part be attributed to the targeted strengthening programme instigated after the June 2006 snow storm.

A storm robustness and performance review of Orion's previous design standards for the 11kV rural network was carried out by an independent consultant. This review indicated that, in some cases during the impact of adverse weather (storms) events, the lack of strain structures was inadequate for the loading.

The performance review and Orion's overhead line design standard were based on the standard AS/NZS 1170 – General Design Requirements and Loading on Structures, together with detailed soil type reviews for the Orion network area to ensure correct pole foundations and embedment. Standards are now in place for the installation of all new poles/lines. The new standard AS/NZS 7000 – Overhead line design – Detailed procedures, released in 2010, is not as stringent as Orion's own design standards in the area of line design and loading, confirming our approach to robustness and risk profile.

In the 2010/2011 earthquakes liquefaction affected poles in some areas with excessive settlement or leaning. Service on the whole was able to be maintained, while any rectification work to the foundations was completed with approved methods very quickly.

The 2003 tree regulations introduced a notice regime that defines responsibility for problem trees. Orion put a tree maintenance programme in place for removal of vegetation adjacent to Orion overhead lines to ensure system security. This has incurred significant extra costs for Orion but has resulted in improved reliability.

To improve the performance of the 11kV lines with smaller conductors, we are replacing the cross arms, insulators, conductors (using smooth body ACSR flounder) and installing distribution ties. The ongoing practice of replacing hand binders with distribution ties has reduced the incidence of 11kV conductors coming off insulators. The use of Flounder conductor reduces breakages in lines exposed to snow/ice and high winds.

There have been issues in the past with bi-metallic joints corroding. These joints are being replaced in conjunction with the re-tightening programme or when found during scheduled works.

Timber poles are used extensively for all new/replacement work. The life expectancy of these poles is 35 to 55 years, with a minimal loss of strength after 25 years in service. Improved treatment procedures mean that Orion expects poles will last longer than this in future. Poles in more exposed areas such as Banks Peninsula and Arthur's Pass may need to be replaced at 30 to 35 year intervals due to harsh environmental conditions such as strong winds, snow and ice and heavier rainfall.

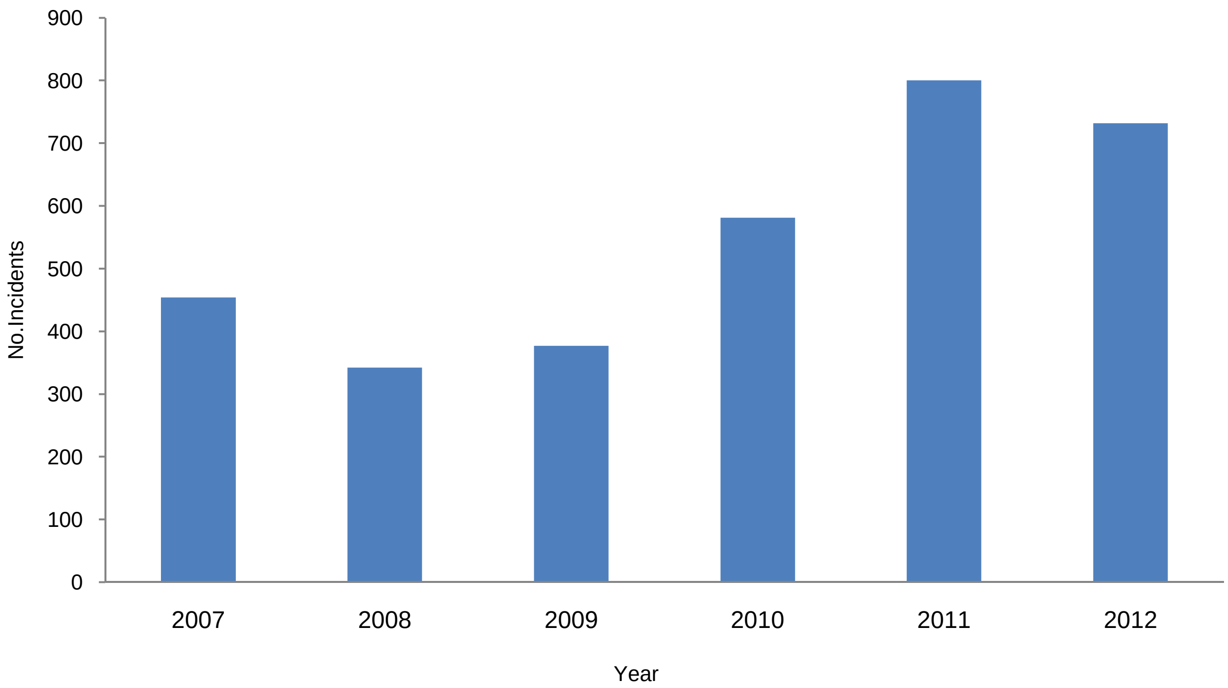
The Port of Lyttelton depends on a secure power supply and could be critical to Christchurch after any natural disaster. A double-circuit line is the only supply to the Port. The status of this line has been raised to that of the subtransmission system. This means a higher level of maintenance and more regular inspections are undertaken than for other 11kV lines. Increased clearances now allow safe maintenance on this line to be performed with the line alive, resulting in no supply interruptions to Lyttelton. These lines suffered no damage during the 2010/2011 earthquakes.

As shown in Figures 7 and 8, emergency maintenance had been low up until the sharp increase in 2010-2012 as a result of damage to the network caused by earthquakes.

Figure 7: Number of 11kV Fault Incidents Per Year

	2007	2008	2009	2010	2011	2012	Total
11kV O/H Emerg Maint	454	342	377	581	800	732	3286

Figure 8: Number of 11kV Fault Incidents Per Year



4 ASSET CONDITION

4.1 GENERAL

Rebuilding is now based on a Condition Assessment Survey. The condition of our main feeder lines is good.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our 11kV overhead lines. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual overhead line. This effectively gives the overhead line a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Figure 9: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 10: Year 0 Health Index Profile

Category	Conductor (m)
(0-1)	672,542
(1-2)	952,979
(2-3)	614,600
(3-4)	318,026
(4-5)	190,006
(5-6)	162,525
(6-7)	190,384
(7-8)	0
(8-9)	415
(9-10)	0
(10+)	0
No Result	0
Total	**3,101,475**

Figure 11: Year 0 Health Index Profile

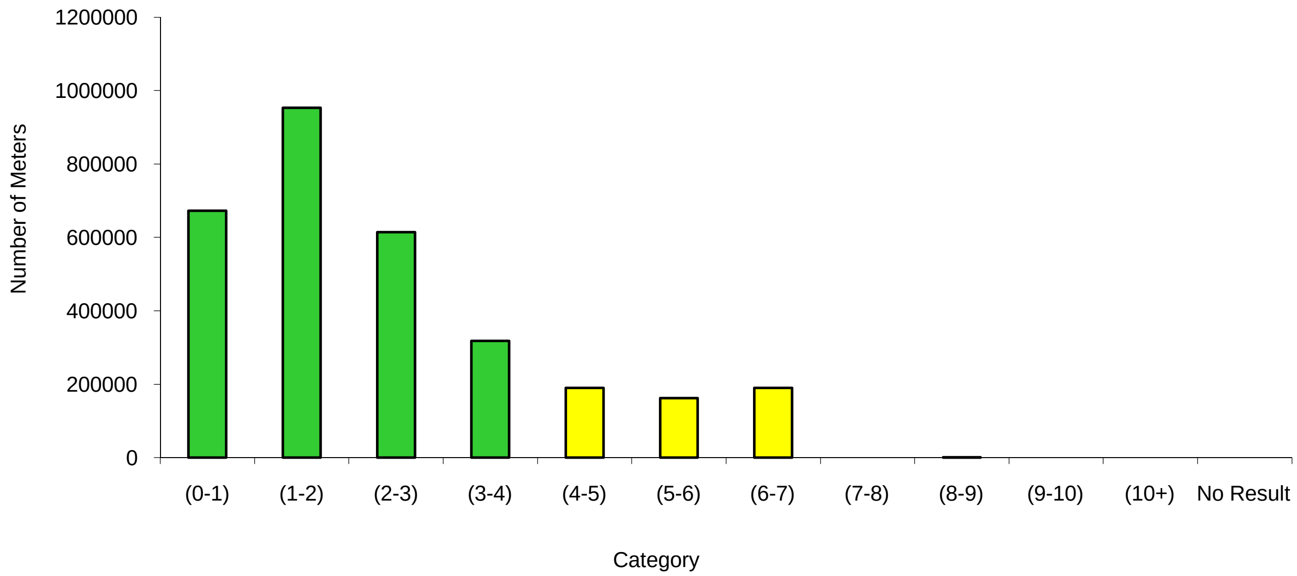


Figure 12: Year 10 Health Index Profile

Category	Conductor (m)
(0-1)	246,360
(1-2)	634,284
(2-3)	590,310
(3-4)	462,944
(4-5)	331,417
(5-6)	232,288
(6-7)	143,409
(7-8)	169,650
(8-9)	88,991
(9-10)	87,924
(10+)	113,899
No Result	0
Total	**3,101,475**

Figure 13: Year 10 Health Index Profile

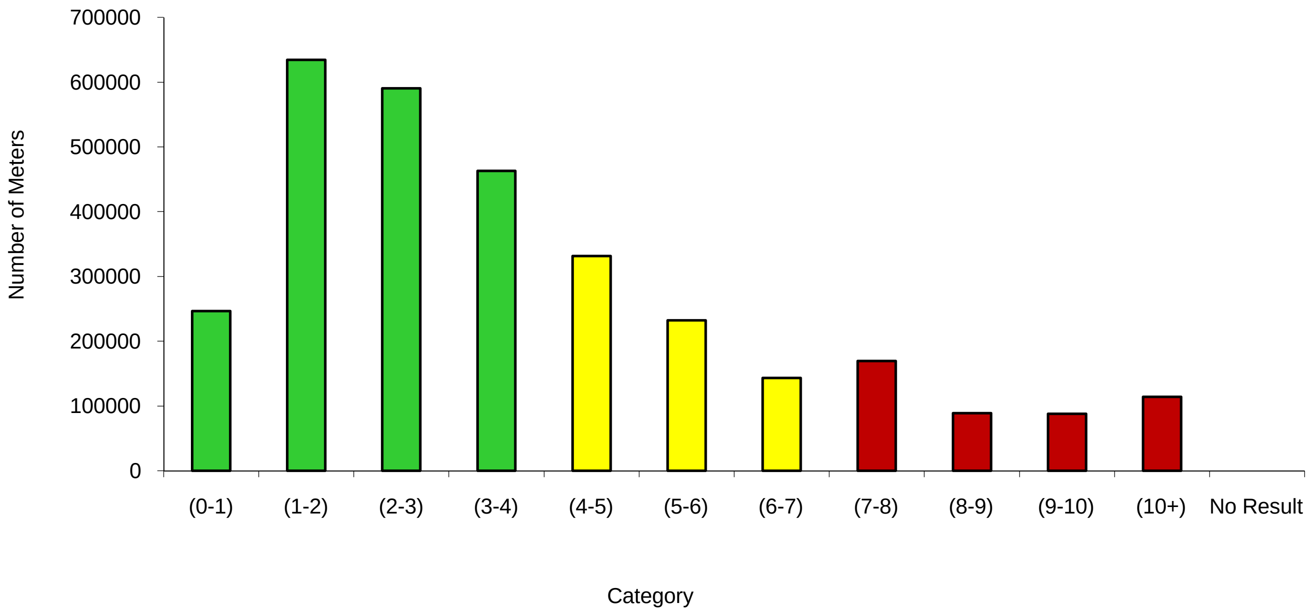


Figure 11 shows the current condition of our 11kV overhead lines population. Figure 13 shows the condition of our 11kV overhead lines population in 10 years time if no further investment is made in the replacement programme.

4.3 HISTORICAL ISSUES

Older/smaller 11kV conductors e.g. No.8 steel and 7/16 steel have been replaced.

Conductors such as 7/.064 copper (conductor breaking load of 5.8kN) have not performed well in storms and are being replaced with flounder ACSR (conductor breaking load of 16.4 kN) as part of the ongoing maintenance programme.

Older inline, end terminations, deviations and right angle poles were not embedded deep enough and had poor foundation design causing the poles to lean over. New standards were developed to improve the foundation design e.g. cement gravel collar and the embedded length was increased.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

Orion has a number of different asset management practices for different asset groups.

- Inspection and Condition Assessment of Overhead Line Structures NW72.21.11. The purpose of this specification is to set out an inspection and assessment procedure for Orion overhead lines.

- Asset Register (EMS-WASP) provides a central resource management application for holding details of key asset types. The assets covered include all major equipment, with less strategic types being added over time. Schedules extracted from this database are used for preventative maintenance contracts.

- Overhead Line Work NW72.21.01 Overhead Line Standard Construction Drawings NW72.21.18, Earthing Installation NW 72.28.01, Earthing Testing NW 72.28.02 and Vibration Dampers NW 72.21.13. These standards outline the methods of line construction and maintenance practices.

- Equipment Specifications - Overhead Conductors NW74.23.17. Treated Softwood Timber Poles NW74.23.06, Hardwood Timber Poles NW74.23.08, Cross Arms NW74.23.19 and Approved Earthing Equipment and Application NW 74.23.20. These specifications set out the requirements for materials intended for use on Orion's overhead electricity network.

5.2 11KV OVERHEAD LINES LIFECYCLE

Four types of poles are used – softwood, hardwood, concrete and steel. The nominal service life of softwood and hardwood poles depends on timber species, preservative treatments and configuration. However, wooden poles in areas exposed to harsh environmental conditions have a reduced nominal service life.

Some concrete poles and hardwoods, mainly in the Lincoln, Springston, Rolleston and Weedons areas, are reaching the end of their life expectancy. The concrete poles are McKendry-type cast concrete with a 7kN Transverse and 1.7kN downline top loading.

Steel and pre-stressed concrete poles are used mainly for subtransmission but are also used in some other cases e.g. river crossings to achieve longer spans.

Crossarms are hardwood timber and some steel.

Insulators are porcelain line post, pin type and porcelain/glass disc strains and composite polymer strain.

Conductors, both aluminium and older copper, are typically at a tension of about 10% of Conductor Breaking Load and therefore extend the life expectancy.

Figure 14: Nominal Service Life

Type	Nominal Life Service (yrs)	Harsh environmental conditions
Pole		
Softwood	35-55	30-35
Hardwood	35-55	30-35
Concrete	50-70	
Steel	70-80	
Crossarms		
Hardwood	30-40	30
Steel	70-80	
Insulators		
Glass	60	
Porcelain	60	
Polymer	30-40	
Conductors	60	

5.3 AGE PROFILES

Figure 15: Age Profile of Orion Owned 11kV Poles by Type

Decade	CON	HW	SW	Total
Pre 1950	702			**702**
1950-1959	1713	394		**2107**
1960-1969	4068	1924	37	**6029**
1970-1979	5805	3832	1167	**10804**
1980-1989	5909	1053	481	**7443**
1990-1999	704	2839	7314	**10857**
2000 to date	5	3753	6305	**10063**
Total	**18906**	**13795**	**15304**	**48005**

Figure 16: Age Profile of Orion Owned 11kV Poles by Type

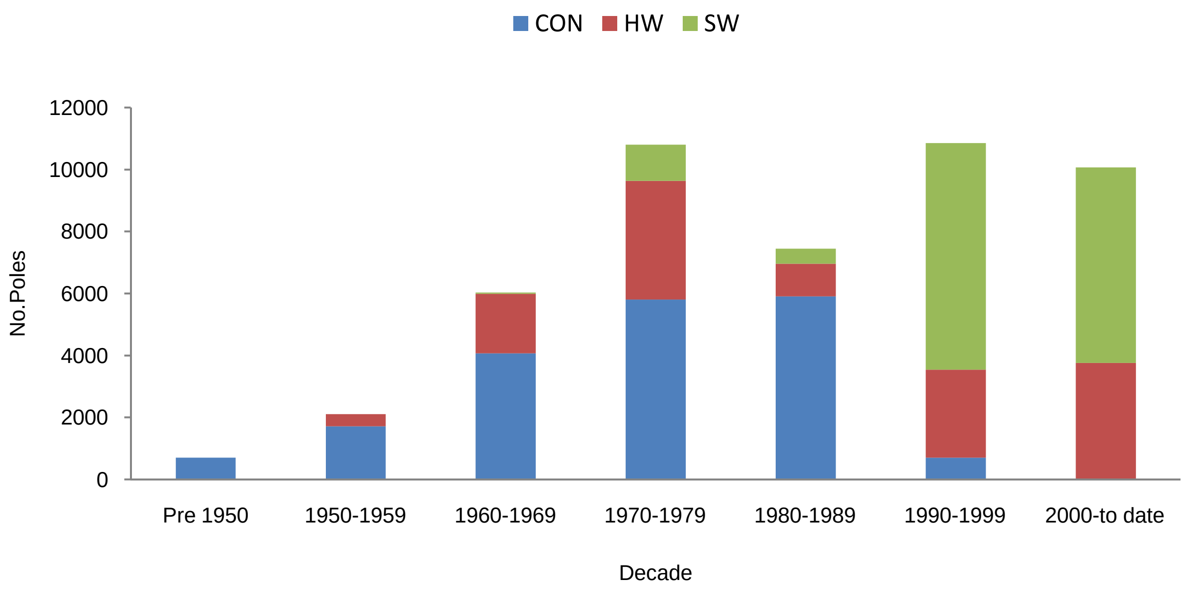
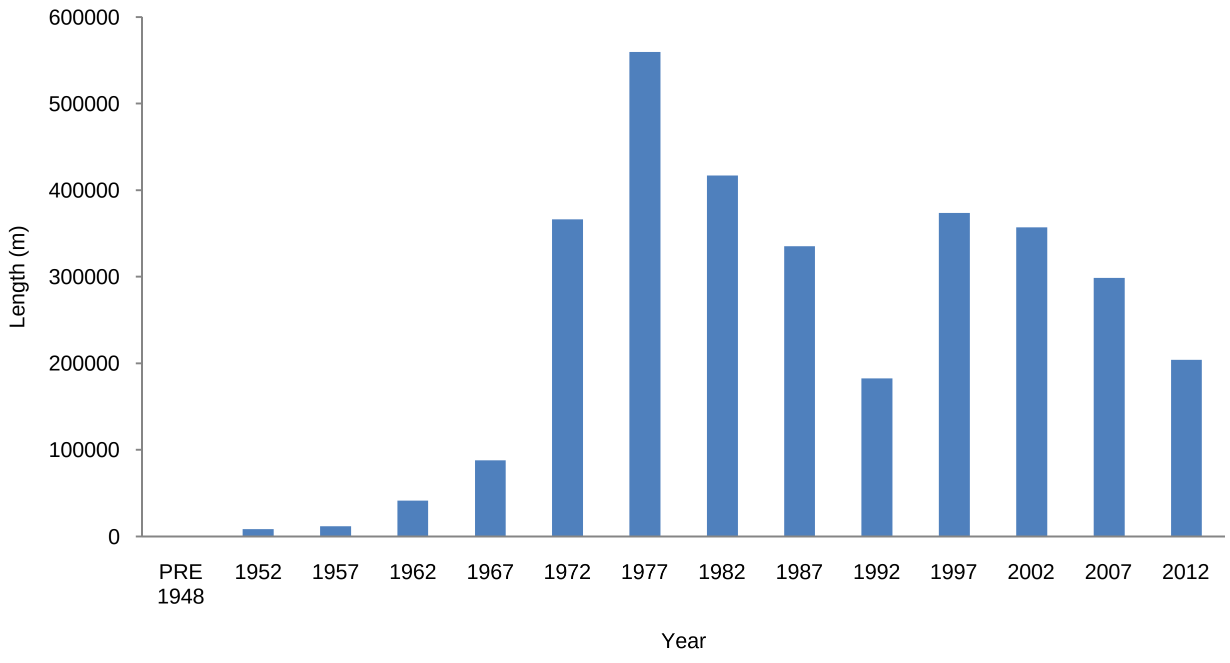


Figure 17: Age Profile of Orion Owned 11kV Overhead Lines



5.4 MAINTENANCE PLAN

The condition of the 11kV overhead line is monitored as per the NZCEP 34 guideline.

Maintenance is primarily based on a 'Condition Assessment Survey' cycle with a street by street visual inspection: Refer to Urban and Rural areas drawing A2 17491 for inspection programme and Orion's Inspection and Condition Assessment of Overhead lines structures and Technical Specification NW 72.21.11 for inspection process. The inspection provides information such as that shown in Figures 18 and 19. These survey results are fed into the CBRM model discussed in Section 4.2.

Figure 18: 11kV Pole Condition by Type

Score	CON	HW	SW	Total
0		13		**13**
2		9	1	**10**
3	2	21		**23**
4	22	146	2	**170**
5	150	903	17	**1070**
6	1401	2105	126	**3632**
7	3289	2965	702	**6956**
8	5492	942	524	**6958**
9	6852	85	1032	**7969**
10	1698	6606	12900	**21204**
Total	**18906**	**13795**	**15304**	**48005**

Score of 10 is a new pole and score of 0 is replacement required.

Figure 19: 11kV Pole Condition Profile

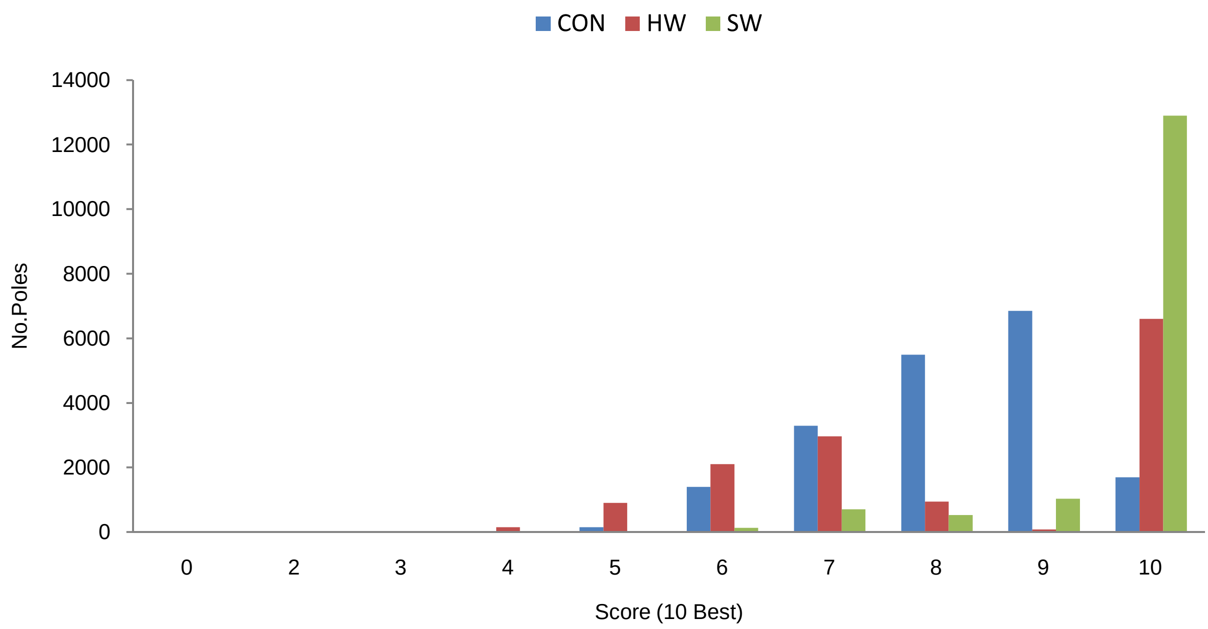


Figure 20: 11kV Maintenance Issues Found

Issue	11kV Pole Inspection Total No.	Sub Total	Notes
Crossarm	2833		
Decay		(2545)	
Split		(194)	
Loose		(63)	
Twisted		(30)	
Insulators	2815		
Leaning		(2491)	
Loose		(293)	
Chipped		(22)	
Split / Cracked		(6)	
Missing		(3)	
Hazards	495		
Exposed Creek		(278)	
Live Line Clamps		(192)	
Pot Head		(18)	
Miscellaneous		(4)	
Joint over Rail		(3)	
U Bolts	485		Identified for future replacement
Signage	361		Faded / missing
Transformer	224		
Oil Leaking		(146)	
Corrosion Tank		(72)	
Corrosion Tx		(6)	
Leaning Pole (EQ)	219		35% probable EQ damage
Nuts	169		Missing / loose
Foundations	117		Sealing
Stays	104		Loose / broken
Conductor	72		Sagging / broken strands
Miscellaneous	101		Pins / binders / braces / cable protect
Total	**7995**		

Other surveys:

- A corona camera inspection is carried out every two years. The use of a Day-Cor Corona Imaging Camera enables the detection of corona, partial discharge and arcing. The camera provides the ability to visually detect partial discharge occurring on equipment e.g. cracked insulators and defective components at early stages of degradation thus minimising unscheduled outages.

- The camera allows inspection of distribution and transmission lines from the ground or helicopter.

- A thermal imaging scan (selected areas as required).Refer to: Thermographic Survey of HV Network NW 72.21.10.

Maintenance work planned is as follows:

- Conductor replacement based on a condition assessment and/or performance issues (worst performance feeder) is carried out during rebuilding. Any existing 7/.064Cu conductors are replaced with Flounder ACSR. Some crossarms, insulators and ties are replaced at this stage also. Maintenance on approximately 130km is carried out per year.

- Live-line re-tightening programme on a feeder by feeder basis of all line components to reduce wear and fatigue on the poles. Refer to Overhead Line Re-Tightening Technical Specification NW 72.21.03. The Retightening Cycle Programme specifies that:
  - new lines/poles are retightened within 12-18 months of installation and
  - retightened at 20 year intervals thereafter.

  At the 20 year mark a full inspection of all equipment is carried out and remedial work is undertaken as required. Some crossarms, insulators and ties are replaced at this stage also. Maintenance on approximately six feeders (150km) is carried out per year.

- As part of the subtransmission (33kV) maintenance, the 11kV underbuilt is maintained:
  - old 821 insulators replaced with new 1130W insulators
  - hand binders replaced with distribution ties
  - replace 7.5mmØ stay wires with new standard stay wires and replace anchor blocks
  - copper tails changed to aluminium tails (bimetal connections)
  - bimetal jumpers and joints replaced
  - line guards to armour guards
  - stay insulators to new standard insulators

  Maintenance on approximately 4km is carried out per year.

- Replacing crossarms and insulators.
  Maintenance on approximately 300 sites is carried out per year.

- Retention conductors for uneven sagging as a result of twisted crossarms.
  Maintenance on approximately 72 sites is carried out per year.

- Orion continues to focus on clearing trees from 11kV lines to comply with the Tree Regulations i.e. Electricity (hazards from trees) 2003 and also Orion Vegetation work adjacent to overhead lines NW72.24.01 in order to reduce unnecessary power outages and damage to the network. Maintenance on approximately 60 feeders is carried out per year.

Earthing

Orion takes a risk based approach to inspection and testing of site earths. Refer to the infrastructure inspection programme for earth sites areas drawing A2 16652. Urban areas have good bonding between earths. Orion concentrates on earthing maintenance in the rural areas as these areas are subject to deterioration because of highly resistive soils, stony sub-layers of earth and corroded earthing systems. Between 2,100 and 2,600 sites are tested in any one year and those requiring repairs are identified and scheduled for repair in the following year. Refer to Approved Earthing Equipment and Application NW74.23.20 and Earthing Installation NW72.28.01and Earthing Testing NW72.28.02.

Other maintenance work is on an as-required basis and depending on results from the inspections.

Figure 21: Annual Maintenance Plan

Maintenance	Approx per year
Conductor replacement	130km
Retightening – 6 feeders	150km
Underbuilt	4km
Replacement of crossarms and insulators	300 sites
Retension conductors	72 sites
Trees	60 feeders

5.5 REPLACEMENT PLAN

Replacement or renewal is primarily based on a periodic 'Condition Assessment Survey' cycle with a street by street visual inspection: Refer to Urban and Rural areas drawing A2 17491 for inspection programme. Orion Inspection and Condition Assessment of Overhead lines structures, Technical Specification NW 72.21.11.for inspection process

The pole replacement programme is derived from the 'Condition Assessment Survey' results. Some older conductors are replaced during scheduled pole replacement work.

Seven- irons and two-pole structures for transformers are replaced as part of planned maintenance and will be completed by 2016.

Other renewal work is on an as-required basis.

5.6 DISPOSAL PLAN

The disposal of poles and hardware replaced during maintenance and conversion works is the responsibility of Orion's Contractors.

Refer to: Works General Requirements NW72.20.04 Clause 5.5 for Disposal of Equipment.

5.7 CREATION / ACQUISITION PLAN

New 11kV lines are now only built in the rural network areas as they are prohibited in urban areas by planning requirements.

Additional 11kV lines are constructed as a result of the following:

- reinforcement plans (refer to section 5.6 – Network development proposals)
- new connections and subdivision developments.

5.8 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.9 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.10 RISK ANALYSIS

Orion undertakes risk assessment analysis on an ongoing basis to ensure all structures and equipment meet current standards. Overall, the risk of asset failure is low.

The primary risks for the 11kV network are that of storms and, to a lesser extent, earthquakes. Storms (e.g. snow, wind and ice) have historically affected the 11kV lines causing more damage in the rural areas than the urban areas particularly for lines crossing the wind direction.

New standards for the maintenance and replacement of 11kV lines were developed following a review that highlighted that in some cases the lack of strain structures was inadequate for the loading and to establish new risk requirements for snow/ice and wind events. Refer to Design Standards - Overhead Line NW70.51.01, Overhead Line Design Manual NW70.51.02, Overhead Line Design Worked Examples NW70.51.03, Overhead Line Technical Manual NW70.51.04., Technical Specification Overhead Line Work NW72.21.01 and Overhead Line Standard Construction Drawing NW72.21.18.; these are applied to the urban and rural network. These new standards have, and will continue to, reduce the risk of failure on the network.

The ongoing risk of further earthquakes may require remedial work to be carried out on the network as a result of ground movement and liquefaction causing instances of foundation failure and the subsequent leaning of poles and reduced conductor clearance either to other conductors or to the ground.

Trees falling across the 11kV lines also pose a risk. Orion's tree maintenance programme cuts and trims trees on a regular basis and this will continue to reduce the number of outages caused by falling trees. Refer to Orion Vegetation Work Adjacent to Overhead Lines NW72.24.01.

Small conductors, 7/.064Cu cannot be live-lined due to the fatigued state, particularly where the conductor sits on the insulator neck. Over time these are being replaced with flounder ACSR conductor to enable live line work to be carried out.

There are also initiatives underway to further reduce the risk to the network: For example:

- Orion is working with an Australian company on the development of a non-destructive pole tester in order to determine pole condition resulting in early detection of decay and required pole replacement.

- HV cut-out fuses operated under fault conditions can produce sparks that can ignite grass causing a fire. Orion is working with an international company to develop non-spark fuses for use on the network to eliminate this risk.

Materials:

An emergency stock of 11kV line replacement materials is held by our service provider (Connetics, Chapmans Road, Christchurch). It is the responsibility of the service provider to monitor and maintain stock levels (refer to Technical Specifications - Storage and Provision of Emergency Stock and Long term Spares NW72.20.08 and Orion Stock Management NW72.20.11). Some stock is required to be held at Orion's rural depots e.g. Duvauchelles and Dunsandel.

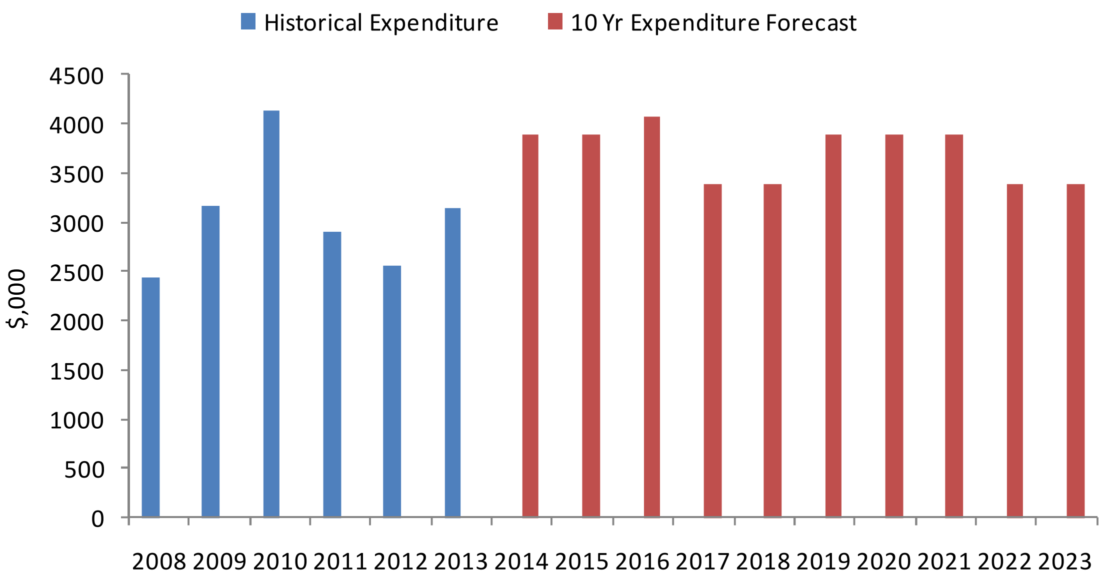
Refer to Equipment Specifications - Overhead Conductors NW74.23.17, Treated Softwood Timber Poles NW74.23.06, Hardwood Timber Poles NW74.23.08, Cross Arms NW74.23.19. This specification sets out the requirements for materials, intended for use on Orion's overhead electricity network.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 22: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 23: Historical 11kV Overhead Lines Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	1546	2238	2993	1933	1599	2030
Non-Scheduled	240	216	460	264	217	415
Emergency	657	720	683	709	740	700
Total	**2443**	**3174**	**4136**	**2906**	**2557**	**3145**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

The major components that make up our Opex spend are our vegetation management programme and pole survey. While both of these were developed in response to the regulations, we have noticed an improvement in performance since their introduction.

Figure 24: 11kV Overhead Lines Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	2520	2520	2520	2030	2030	2520	2520	2520	2030	2030
Non-Scheduled	415	415	415	415	415	415	415	415	415	415
Emergency	950	950	1135	950	950	950	950	950	950	950
Total	**3885**	**3885**	**4070**	**3395**	**3395**	**3885**	**3885**	**3885**	**3395**	**3395**

Our scheduled maintenance for subtransmission overhead lines is tendered as part of our contracting model.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 25: Historical and Forecast Expenditure

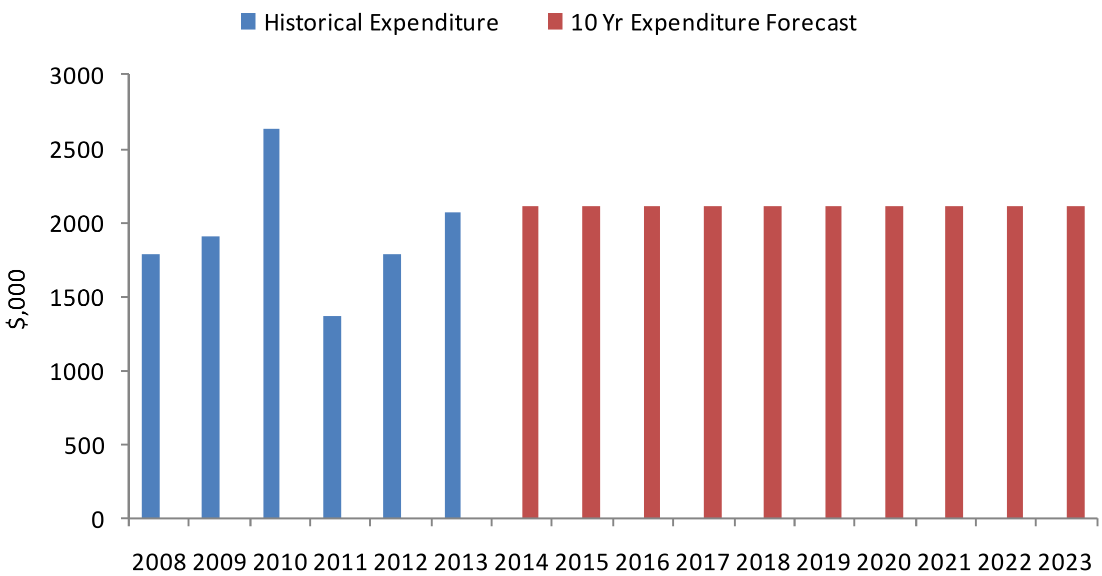


Figure 26: Historical 11kV Overhead Lines Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	1785	1910	2657	1391	1772	2065
Total	**1785**	**1910**	**2657**	**1391**	**1772**	**2065**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 27: 11kV Overhead Lines Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	2115	2115	2115	2115	2115	2115	2115	2115	2115	2115
Total	**2115**	**2115**	**2115**	**2115**	**2115**	**2115**	**2115**	**2115**	**2115**	**2115**

Appendix A

Method of Calculation

All the line ratings shown in Figures 4-6 have been calculated using the IEEE 738-1993 standard as guidance. This method is internationally recognised and utilises the heat balance formula to calculate the current-temperature relationship of bare overhead conductors.

Local weather data gathered from a National Institute of Water and Atmospheric Research (NIWA) weather station located in the township of Lincoln was used. The data was 10 minute average values of ambient temperature, wind speed and intensity of solar radiation

Correlations between wind speed vs. ambient temperature and intensity of solar radiation vs. ambient temperature were made and equations were formed to capture 99% of all the observed weather patterns, i.e. captures all except the very extreme lowest wind speed / highest ambient temperature and highest solar intensity / highest ambient temperature situations. The established correlations were then used as variables in the calculation.

To observe the season variability of the ambient temperature, wind speed and intensity of solar radiation the summer period was defined from November through to February inclusive and winter was defined from June through to August inclusive.

Daytime was defined where the solar angle was above the horizon and night-time below.

The four combinations of day/night and summer/winter were calculated and the lowest rating was determined. This is a conservative approach, but makes operation of the network simpler because only one rating is required.

Wind attack angle is considered, but because Orion's network is so highly meshed with a web like pattern, a wind attack angle based upon the prevailing winds in Canterbury would be meaningless. A sensitivity analysis was done to ascertain the impact wind attack angle had on the thermal rating of a Dog conductor line with the various time and season combinations. The conclusion of this analysis was that with a maximum design temperature of 70degC the varying wind angle did not greatly affect the minimum ratings for the changing ambient air temperature. Therefore a very conservative fixed value of 25 degrees (off-parallel) was used throughout the calculations.

Wind shielding due to vegetation is almost impossible to quantify generically so must be considered on a case-by-case basis.

For bare conductors the emissivity and absorptivity have been assumed to be 0.5, which can be deemed an average where the range is from 0.23 for new conductors to 0.91 for black "aged" conductors. Covered conductors with a black XLPE outer sheath have an assumed emissivity and absorptivity of 0.95.

The effect of increasing conductor resistance with increasing operating temperature has been accounted for in the calculations using a formula that considers the conductor material and the conductor temperature rise.

The temperature gradient of covered conductors was accounted for using the method as used in the standard IEC 60287 Electric Cables – Calculation of the Current Rating that considers the thermal resistance of the outer sheath.

Low Voltage Overhead Lines

Asset Management Report YE 2012

NW70.00.25

Table of Contents

1 INTRODUCTION

This document covers each of our low voltage (LV) overhead line categories and details the criteria and asset management practices used to ensure Orion obtain effective performance and acceptable service life from these lines.

The LV distribution overhead lines which are located mainly in Orion's urban areas and country townships, supply the service lines/cables feeding the consumers in the area. There are instances where such lines cross private property. A Condition Assessment Survey is carried out every five years to identify the maintenance requirements for the LV lines and the necessary hardware/pole replacements.

2 ASSET DESCRIPTION

2.1 GENERAL

Our LV distribution overhead system is 3,059km circuit length of lines, mainly within the Christchurch urban area. This length includes 946km of street lighting circuit. These LV lines are constructed using timber and concrete poles and various conductor types as shown in Figure 1 and 2.

The urban LV network is a multiple earthed neutral system (MEN) operating at 400V between phases and 230V to earth. The urban network can be interconnected with adjacent substations by installing ties (where available) at various normally open points.

Lines on private property:

Owners are responsible for the safety of lines that they own. Orion provides a maintenance service to our consumers for lines that they own, and the cost of this service forms part of our line charge.

Figure 1: LV Pole Types

Pole Type	Urban Mainline	Urban Backsection	Urban Streetlight	Rural	Total
CONCRETE	**8244**	**111**	**102**	**1309**	**9766**
A	543	12	37	129	
B	1380	1	6	4	
L	2392	38	35	106	
PCAST	89	22	3	980	
T	3823	38	20	103	
TX	17		1		
HARDWOOD	**7879**	**924**	**60**	**3422**	**12285**
HW	7879	924	60	3422	
SOFTWOOD	**4661**	**3543**	**156**	**6114**	**14474**
LARCH	114	1065	67	958	
SW	4547	2478	89	5159	
Totals	**20784**	**4578**	**318**	**10845**	**36525**

Figure 2: LV Overhead Conductors

Conductor Type	Cct Length (m)	Avg Age (Yrs)
1p 7/.064Cu	283	24
2p 7/.064Cu	124	25
3p 7/.064Cu	11277	20
1p 7/.083.Cu	2337	30
2p 7/.083Cu	1221	43
3p 7/.083Cu	40459	32
1p 19/.064Cu	510	23
3p 19/.064Cu	113269	39
3p 19/.083Cu	401557	37
3p 37/.083Cu	45706	41
3p NAMU	178	19
3p RANGO	3692	19
3p WEKE-19	107868	40
3p WEKE-7	826	25
Unknown	653119	33
Totals	**1,382,426**	**35**

2.2 ASSET TYPES

LV overhead lines are made up of various combinations of asset type materials. Refer to Figures 1 and 3 for information relating to pole type treatment and Figures 13, 14 and 15 regarding age profile. For other materials e.g. crossarms and insulators refer to Overhead Lines Standard Construction Drawing Set: NW72.21.18.

Figure 3: LV Poles (Type and Treatment by Length)

Pole Type	6m	8m	8.5m	8.7m	9m	9.5m	10m	10.5m	11m	12m	12.5m	13m	14m	15m	Total
Concrete			**7993**		**487**	**810**	**456**	**20**							**9766**
Hardwood	**100**	**9**	**2873**	**8**	**2416**	**3126**	**2011**	**212**	**1415**	**95**	**9**	**6**	**4**	**1**	**12285**
CCA	2	1	48	1	104	1948	1413	6	1171	48	4	2	2	1	4751
None	98	8	2825	7	2312	1178	598	206	244	47	5	4	2		7534
Softwood	**638**	**21**	**2934**	**3**	**5892**	**2732**	**1610**	**16**	**580**	**46**	**2**				**14474**
CCA	125	7	1003		4500	2535	1602	14	577	44	2				10409
CRSOTE	409	10	1077	1	604	94	4	2	2	1					2204
S25	104	4	854	2	788	103	4		1	1					1861
Total	**740**	**30**	**13798**	**11**	**8795**	**6668**	**4077**	**248**	**1995**	**141**	**11**	**6**	**4**	**1**	**36525**

3 ASSET PERFORMANCE

The ratings of the standard LV polyvinyl-chloride (PVC) covered conductors are itemised in Figure 4 below. Ratings are based on 20°C ambient and 30°C conductor rise.

The network has proven to be robust and performs well.

The 2003 tree regulations introduced a notice regime that defines responsibilities for problem trees. This has brought significant extra costs for Orion, but has resulted in improved reliability.

As shown in Figures 5 and 6, emergency maintenance had been low up until the sharp increase in 2012 as a result of damage to the network caused by earthquakes.

Figure 4: Standard LV Conductors

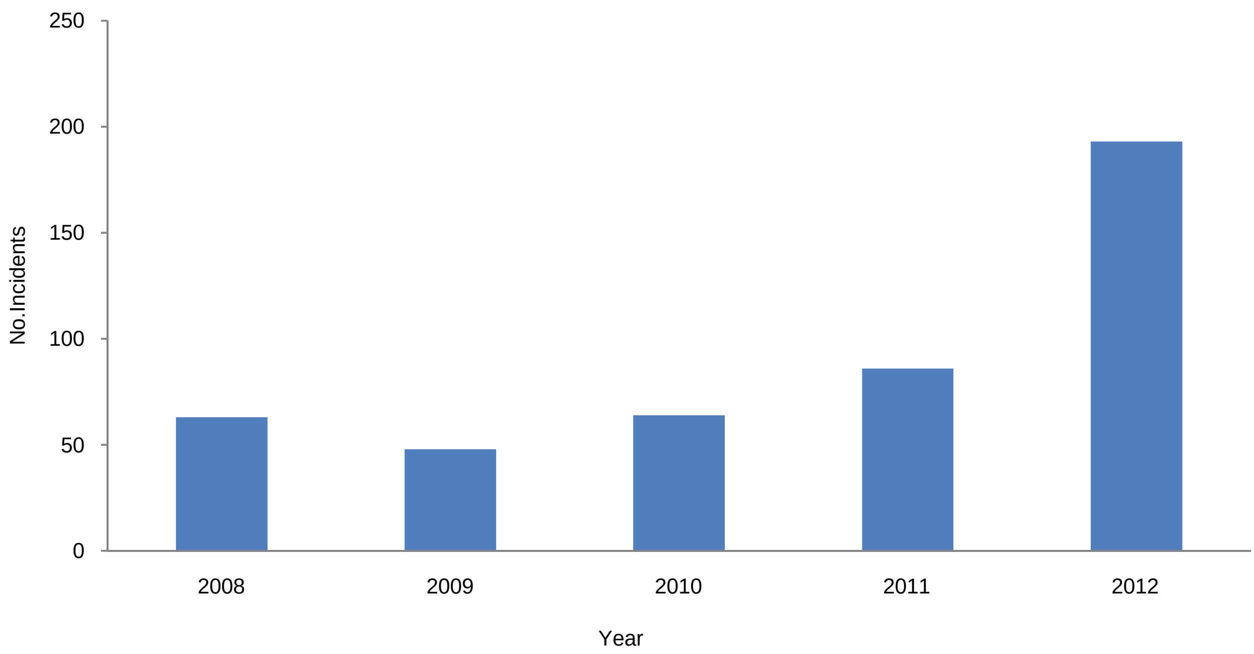
Conductor (Aluminium)	Rating (Amps)
Weke AAC	229
Rango AAC	221
Namu AAC	114

Conductor (Copper)	Rating (Amps)
37/0.083 HD	395
19/0.083 HD	265
19/0.064 HD	195
7/0.083 HD	144
7/0.064 HD	106

Figure 5: No. of LV Fault Incidents per year (Recorded in Works Management)

	2007	2008	2009	2010	2011	2012	Total
400 O/H Emerg Maint	889	748	548	983	1746	1925	6839

Figure 6: Number of LV Fault Incidents per year (Recorded in Works Management)



4 ASSET CONDITION

4.1 GENERAL

An assessment of the design of our previously installed LV poles has indicated that, in some cases, the pole foundation strength was inadequate for the loading. This was determined using the requirements of the standard AS/NZS 1170 – General Design Requirements and Loading on Structures, and the results of a detailed geotechnical investigation for surface soils in the Christchurch urban area, together with detailed soil type reviews for the Orion network area. Standards are now in place for installation of all new poles, along with design standards. The new standard AS/NZS 7000 – Overhead line design – Detailed procedures, released in 2010, is not as stringent as our own design standards in the area of line design and loading, confirming our approach to robustness and risk profile.

During 2001 and 2002 a telecommunications company installed a communications network in a large portion of the Christchurch urban area. This required a major pole inspection and assessment programme to determine if existing poles were capable of supporting a communication network. As a result of this analysis, we replaced approximately 4,300 poles. The foundations of a considerable number of other poles were also upgraded over the two year period. In conjunction with the assessment programme, all poles, including deeded poles from Chorus (previously Telecom), streetlight poles with overhead reticulation and back-section service poles were inspected and assessed. A large number of the back-section poles were found to be nearing the end of their life expectancy. The ongoing requirement of pole inspections prior to attachment by the telecommunications network will ensure that existing poles are not overloaded and are replaced when found to be under strength or nearing the end of their useful lives.

Timber poles are used extensively for all new/replacement work. The life expectancy of these poles is 35 to 55 years, with a minimal loss of strength after 25 years in service. Improved treatment procedures mean that we expect poles will last longer than this in future. Poles in more exposed areas such as Banks Peninsula and Arthur's Pass may need to be replaced at 30 to 35 year intervals due to harsh environmental conditions such as higher winds, snow and ice and heavier rainfall.

The LV network conductors are predominantly PVC covered, but in some older areas triple braid (TB), that has poor insulation properties, is still in use. Conductors with this type of covering are replaced during scheduled pole replacement work.

The network has withstood several major snow storms over the last six years, with the urban areas being particularly hit in the last three years, has proven to be robust and performed very well. The major damage was due to trees bringing down lines rather than deficiencies in design or installation. The major earthquakes experienced in Canterbury and in particular in Christchurch since September 2010 have again shown the robustness of the overhead network. While liquefaction affected poles in some areas with excessive settlement or leaning, service on the whole was able to be maintained, while any rectification work to the foundations was completed with approved methods very quickly.

Orion has put a tree maintenance programme in place. This covers the works for the vegetation removal to be carried out adjacent to Orion overhead power lines to ensure an ongoing continuity of supply and system security.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our LV overhead lines population. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual overhead line. This effectively gives the overhead line a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

The CBRM models are used to determine the health index indicating where deteriorations of the asset are taking place. Figures 8, 9, 10 and 11 provide an overall picture of the asset.

Figure 7: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 8: Year 0 Health Index Profile

Category	Conductor (m)
(0-1)	293,624
(1-2)	519,093
(2-3)	469,761
(3-4)	89,063
(4-5)	10,338
(5-6)	2,607
(6-7)	2,542
(7-8)	571
(8-9)	0
(9-10)	0
(10+)	0
No Result	17,442
Total	**1,405,041**

Figure 9 shows the current condition of our LV overhead lines. Figure 11 shows the condition of our LV overhead lines in 10 years time if no further investment is made in the replacement programme.

Figure 9: Year 0 Health Index Profile

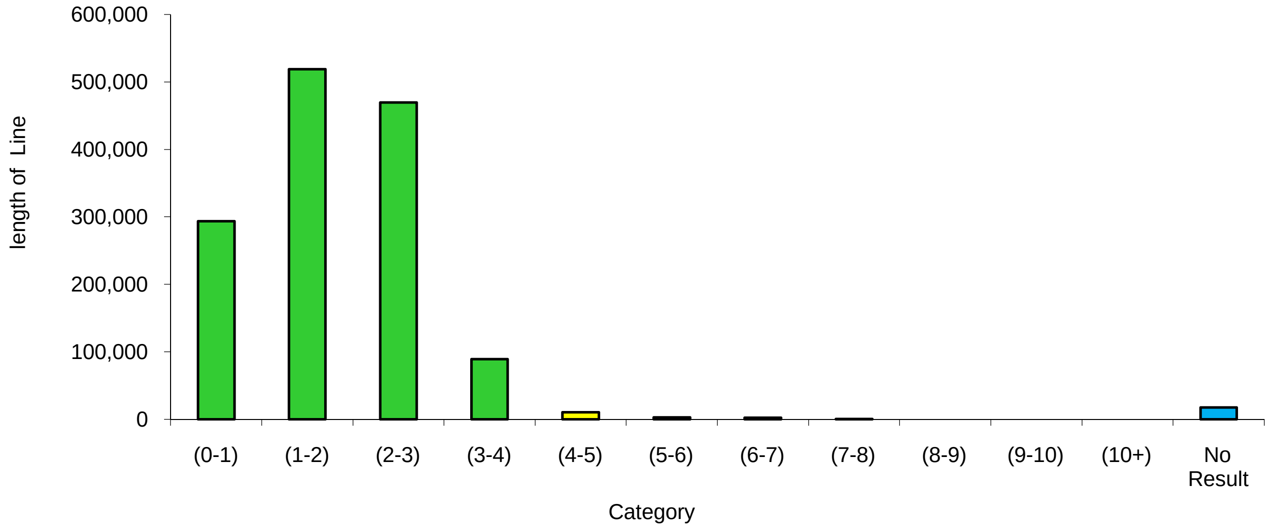
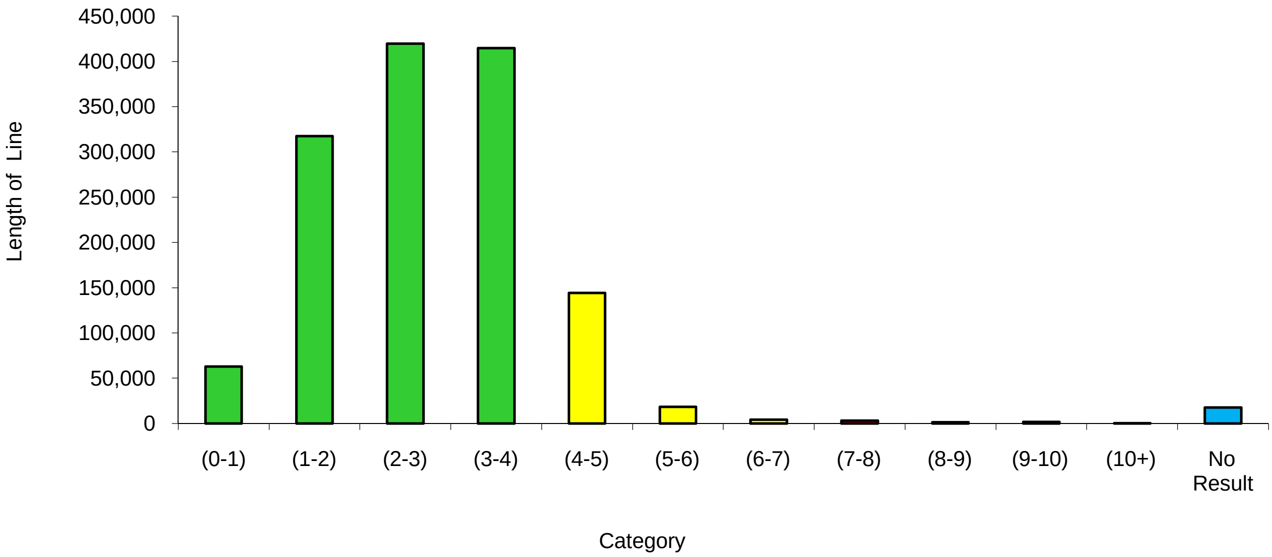


Figure 10: Year 10 Health Index Profile

Category	Conductor (m)
(0-1)	62,955
(1-2)	317,298
(2-3)	419,648
(3-4)	414,653
(4-5)	144,050
(5-6)	18,487
(6-7)	4,123
(7-8)	3,070
(8-9)	1,326
(9-10)	1,677
(10+)	311
No Result	17,442
Total	**1,405,041**

Figure 11: Year 10 Health Index Profile



4.3 HISTORICAL ISSUES

Older end terminations, deviations and right angle poles (unstayed) were not embedded deep enough and had poor foundation design causing the poles to lean over.

New Standards were developed to improve the foundation design e.g. cement gravel collar and the embedded length was increased.

Older wooden square poles, tramway poles and steel poles were identified as suspect due to ground rot. These were replaced approximately two years ago.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

Orion has a number of different asset management practices for different asset groups.

- Inspection and Condition Assessment of Overhead Line Structures NW72.21.11. The purpose of this specification is to set out an inspection and assessment procedure for Orion overhead lines.

- Asset Register (EMS-WASP) provides a central resource management application for holding details of key asset types. The assets covered include all major equipment, with less strategic types being added over time. Schedules extracted from this database are used for preventative maintenance contracts and network valuation purposes.

- Overhead Line Work NW72.21.01 and Overhead Line Standard Construction Drawings NW72.21.18. These standards outline the methods of line construction and maintenance practices.

- Equipment Specifications - Overhead Conductors NW74.23.17 Treated Softwood Timber Poles NW74.23.06, Hardwood Timber Poles NW74.23.08, Cross Arms NW74.23.19. This specification sets out the requirements for materials, intended for use on Orion's overhead electricity network.

5.2 LV OVERHEAD LINES LIFECYCLE

Three types of poles are used – softwood, hardwood and concrete. The nominal service life of softwood and hardwood poles depends on timber species, preservative treatments and configuration. However, wooden poles in areas exposed to harsh environmental conditions have a reduced nominal service life.

Figure 12: Lifecycle of Overhead Lines

Type of Poles	Nominal Life Service (yrs)	Harsh environmental conditions
Softwood	35-55	30-35
Hardwood	35-55	30-35
Concrete	50-70	
Crossarms	30-40	30
Insulators	60	
Conductors	60	

Conductors: Aluminium and copper conductors are used with typically short spans which are low tension about 5% of CBL (Conductor Breaking Load) and therefore extend the life expectancy. A nominal life of 60 years has been assigned.

Figure 13: Age Profile of Orion owned LV Poles by Type

Decade	CON	HW	SW	Total
Pre 1950	52	1	1	54
1950-1959	323	286	1	610
1960-1969	4026	2381	1974	8381
1970-1979	1170	4826	1909	7905
1980-1989	2112	54	951	3117
1990-1999	2074	1188	2967	6229
2000 to date	9	3549	6671	10229
Total	9766	12285	14474	36525

Figure 14: Age Profile LV Poles

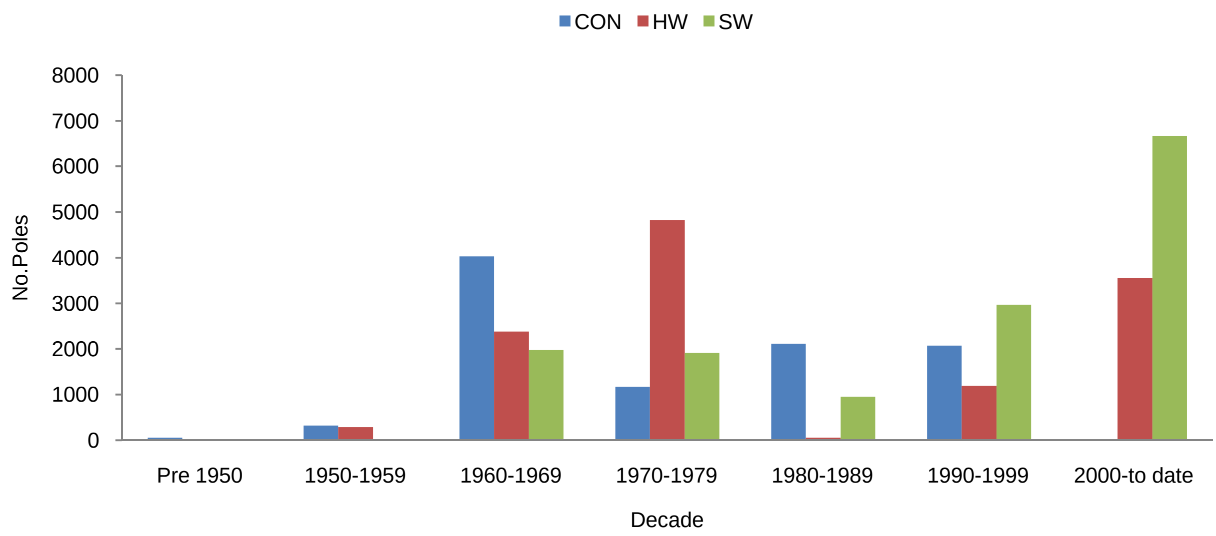
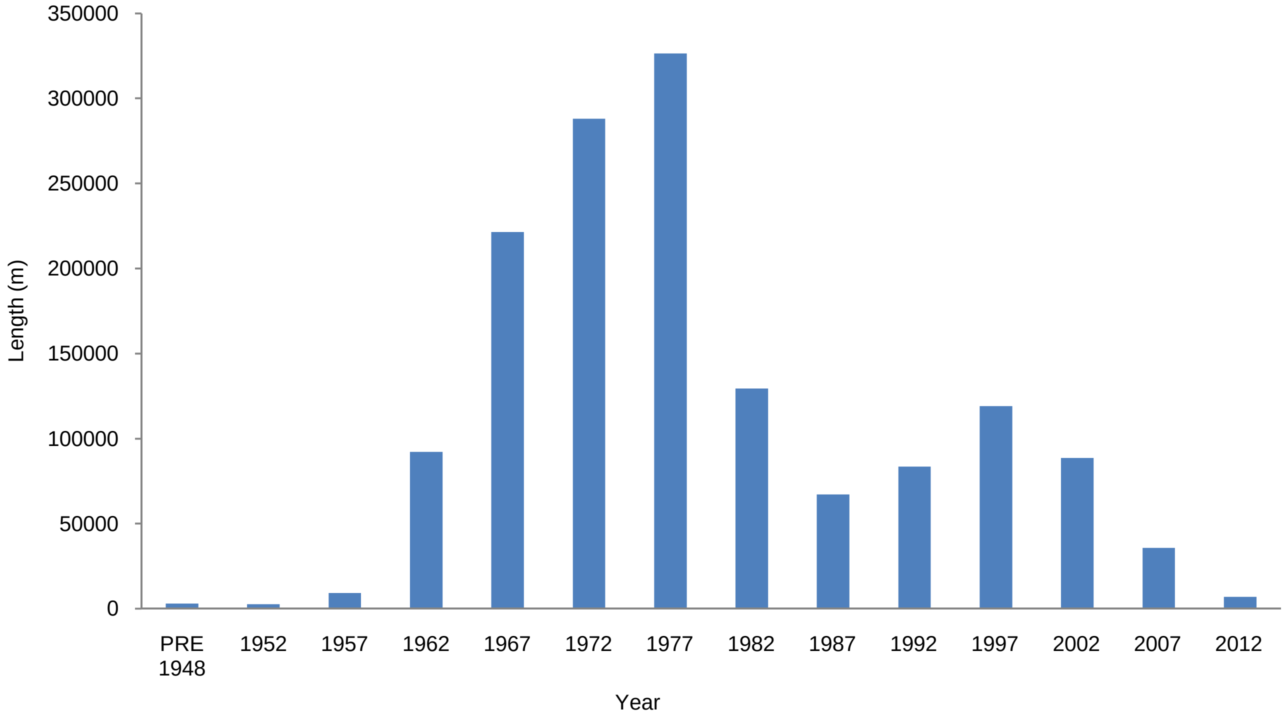


Figure 15: Age Profile LV Overhead Lines



5.3 MAINTENANCE PLAN

The condition of the LV overhead line is monitored as per the NZCEP 34 guideline.

Maintenance is primarily based on a 'Condition Assessment Survey Cycle' with a street by street visual inspection: Refer to Urban and Rural areas drawing A2 17491 for inspection programme and Orion's Inspection and Condition Assessment of Overhead lines structures and Technical Specification NW72.21.11 for inspection process. The inspection provides information such as that shown in Figures 16 and 17.

Figure 16: LV Poles - Condition by Type

Score	CON	HW	SW	Total
0		18	5	23
1		3	1	4
2		19		19
3	6	128	15	149
4	31	359	22	412
5	145	1186	173	1504
6	705	2992	710	4407
7	2163	2557	1789	6509
8	2521	276	1705	4502
9	1650	67	1166	2883
10	2545	4680	8888	16113
Total	9766	12285	14474	36525

Score of 10 is a new pole and score of 0 is replacement required. These results are fed into the CBRM model discussed in Section 4.2.

Figure 17: LV Poles - Condition

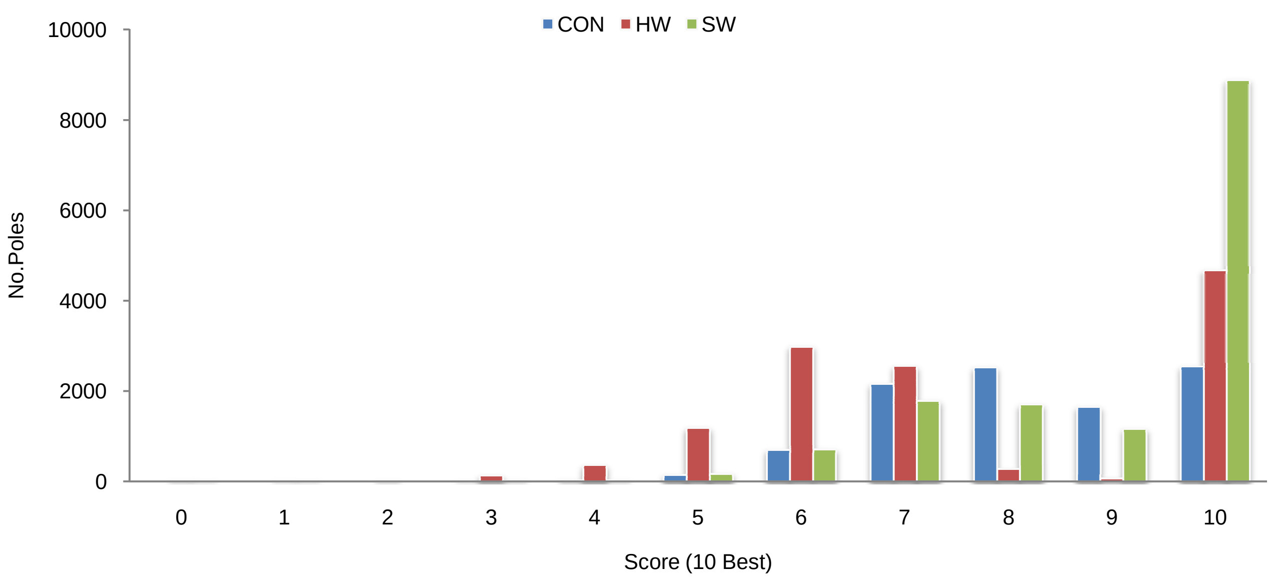


Figure 18: LV Maintenance Issues Found

Issue	LV Pole Inspection Total No.	Sub Total	Notes
U Bolts	3463		Identified for future replacement
Conductor	2491		Uneven sagging
Leaning Pole (EQ)	1940		71% probable earthquake damage
Crossarm	1823		
Decay		(751)	
Split		(408)	
Loose		(505)	
Twisted		(129)	
Insulators	1401		
Leaning		(904)	
Split / Cracked		(86)	
Loose		(218)	
Chipped		(187)	
Nuts	544		Missing / loose
Foundations	625		Sealing / subsidence
LV Fuses	107		
Cracked		(1)	
Chipped		(74)	
Loose		(8)	
Exposed Creek	103		
Miscellaneous	1136		
Cable / Protection		(191)	Cracked / missing / loose
Cable Tails		(92)	UV damage
Minor Defects		(309)	Pins, binders, shackels
Total	**13089**		

Maintenance work planned is as follows:

- Re-tightening programme on a street by street basis of all line components to reduce wear and fatigue on the poles. Refer to Overhead Line Re-Tightening Technical Specification NW72.21.03. The Retightening Cycle Programme specifies that:
  - new lines/poles are retightened within 12-18 months of installation and
  - re-tightened at 30 year intervals thereafter.

At the 30 year mark a full inspection of all equipment is carried out and remedial work is undertaken as required. Some crossarms, insulators and binders are replaced at this stage also. Maintenance on approximately 2000 poles is carried out per year.

- Replacement of crossarms and insulators.
- Retention conductors for uneven sagging as a result of twisted crossarms. Maintenance on approximately 130 sites is carried out per year.
- Orion continues to focus on clearing trees from LV lines to comply with the Tree Regulations i.e. Electricity (hazards from trees) 2003 also Orion Vegetation work adjacent to overhead lines NW 72.24.01 in order to reduce unnecessary power outages and damage to the network. Maintenance on approximately 5000 street properties is carried out per year.

The Christchurch City Council installs various outreach street lighting arms and tsunami alert warning sirens on our poles. Arc Innovations has also installed antennas and equipment for remote metering on existing poles. On these occasions the additional loading to the poles is assessed and requires some poles to be changed to meet the additional load.

Other maintenance work is on an as-required basis.

5.4 REPLACEMENT PLAN

Replacement or renewal is primarily based on a periodic Condition Assessment Survey Cycle with a street by street visual inspection: Refer to Urban and Rural areas drawing A2 17491 for inspection programme. Orion Inspection and Condition Assessment of Overhead lines structures, Technical Specification NW72.21.11 for inspection process

5.4.1 Renewal

The condition of our overhead LV lines is generally good. The pole replacement programme is derived from a Condition Assessment Survey. Some older bare/triple braid conductors with poor covering are replaced during scheduled pole replacement work.

Other renewal work is on an as-required basis.

5.5 DISPOSAL PLAN

The disposal of poles and hardware replaced during maintenance is the responsibility of Orion's Contractors.

LV poles/hardware removed during underground conversion projects are also disposed of by the Orion Contractor/s.

Refer to: Works General Requirements NW 72.20.04 Clause 5.5 for Disposal of Equipment.

5.6 CREATION / ACQUISITION PLAN

New LV distribution lines are now only built in the networks rural areas as they are prohibited in urban areas by city/district plan requirements. They are generally constructed in response to consumer connection requirements only.

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.9 RISK ANALYSIS

During the last 12 years a number of risk assessments have been carried out and reports prepared to determine the capability of the LV network in the urban areas to carry additional loads in particular telecommunications network. Pole strengths, pole types and foundations were assessed. This has resulted in the development of new Standards for the maintenance and replacement of LV lines. (refer to Design Standards - Overhead Line NW70.51.01, Overhead Line Design Manual NW70.51.02, Overhead Line Design Worked Examples NW70.51.03, Overhead Line Technical Manual NW70.51.04., Technical Specification Overhead Line Work NW72.21.01 and Overhead Line Standard Construction Drawing NW72.21.18.) and these are now applied to the urban and rural network.

The primary risks for the LV network is that of storms and, to a lesser extent, earthquakes.

Storms (e.g. snow, wind and ice) have historically affected the LV lines causing more damage in the rural areas than the urban areas particularly due to the lines crossing the wind direction.

Both rural and urban areas suffer from trees falling across the LV lines. Because of this, Orion has put a tree maintenance programme in place whereby trees are cut and trimmed on a regular basis i.e. every five years in the urban areas and every two years in the rural areas. The tree maintenance programme has reduced the number of outages caused by falling trees. This policy meets the requirements of Electricity (hazards from trees) 2003 and Orion Vegetation work adjacent to overhead lines NW72.24.01.

Earthquakes affected the LV lines across the network. Ground movement and liquefaction as a result of the earthquakes caused instances of foundation failure and the subsequent leaning of poles and reduced conductor clearance either to other conductors or to the ground. All unsafe poles and lines have been rectified to the new standards. Other leaning poles will be rectified under the normal maintenance schedule.

Materials:

An emergency stock of LV line replacement materials is held by our service provider (Connetics, Chapmans Road, Christchurch). It is the responsibility of the service provider to monitor and maintain stock levels (refer to Technical Specifications - Storage and Provision of Emergency Stock and Long term Spares NW72.20.08 and Orion Stock Management NW72.20.11). Some stock is required to be held at Orion's rural depots e.g. Duvauchelle, Dunsandel.

Refer to Equipment Specifications - Overhead Conductors NW74.23.17, Treated Softwood Timber Poles NW74.23.06, Hardwood Timber Poles NW74.23.08, Cross Arms NW74.23.19. This specification sets out the requirements for materials, intended for use on Orion's overhead electricity network.

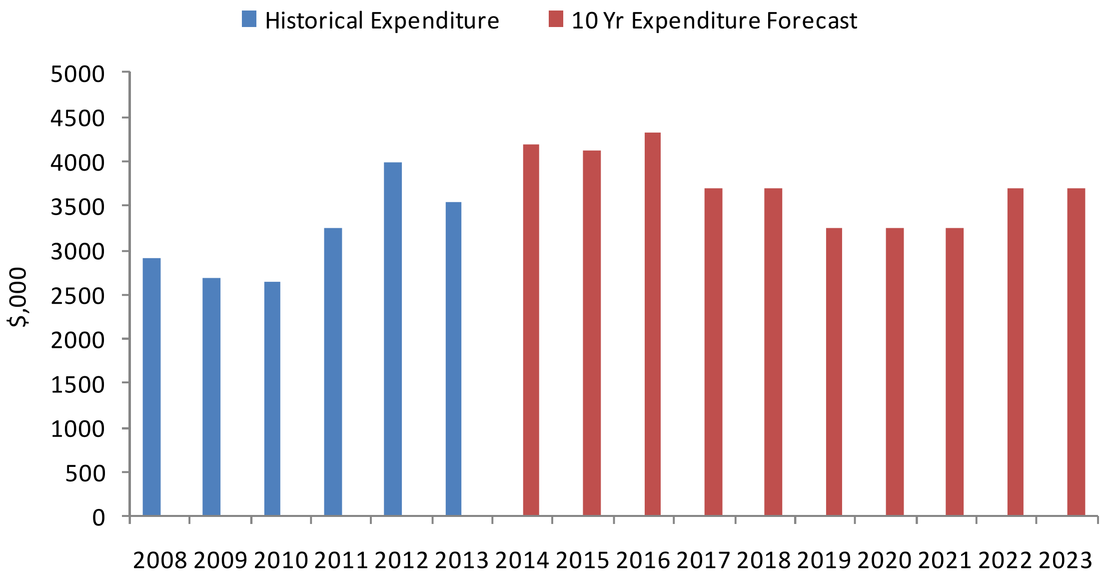
Overall, the risk of asset failure is low.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our maintenance is based on maintaining our current levels of safety and reliability.

Figure 19: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 20: Historical LV Overhead Lines Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	1722	1446	1435	1190	1601	2515
Non-Scheduled	494	692	613	602	516	330
Emergency	698	553	590	1450	1875	700
Total	**2914**	**2692**	**2639**	**3242**	**3992**	**3545**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

The major components of our Opex spend are the vegetation management programme and pole survey.

Figure 21: LV Overhead Lines Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	2905	2850	2850	2425	2425	1975	1975	1975	2425	2425
Non-Scheduled	330	330	330	330	330	330	330	330	330	330
Emergency	950	950	1135	950	950	950	950	950	950	950
Total	**4185**	**4130**	**4315**	**3705**	**3705**	**3255**	**3255**	**3255**	**3705**	**3705**

Our scheduled maintenance for LV overhead lines is tendered out as part of our contracting model.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 22: Historical and Forecast Expenditure

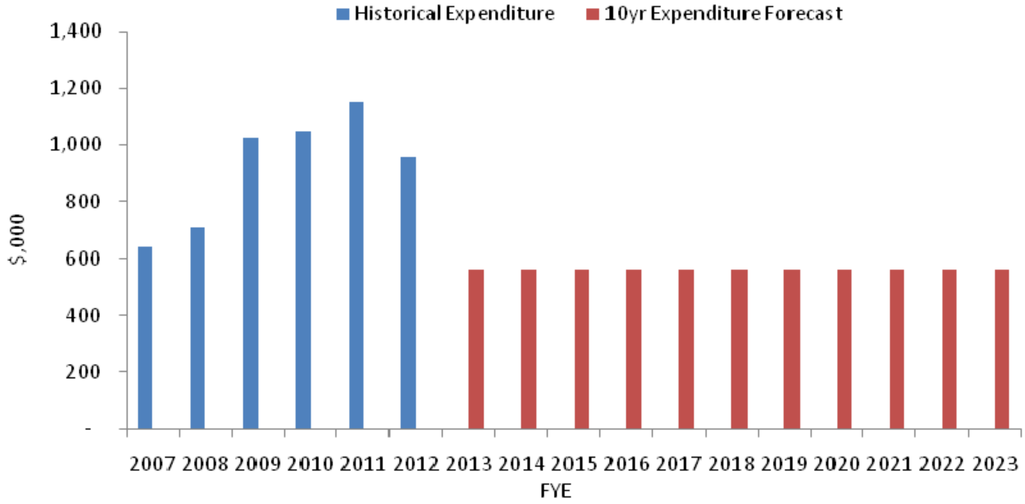


Figure 23: Historical LV Overhead Lines Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	708	1026	1064	1036	651	560
Total	**708**	**1026**	**1064**	**1036**	**651**	**560**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

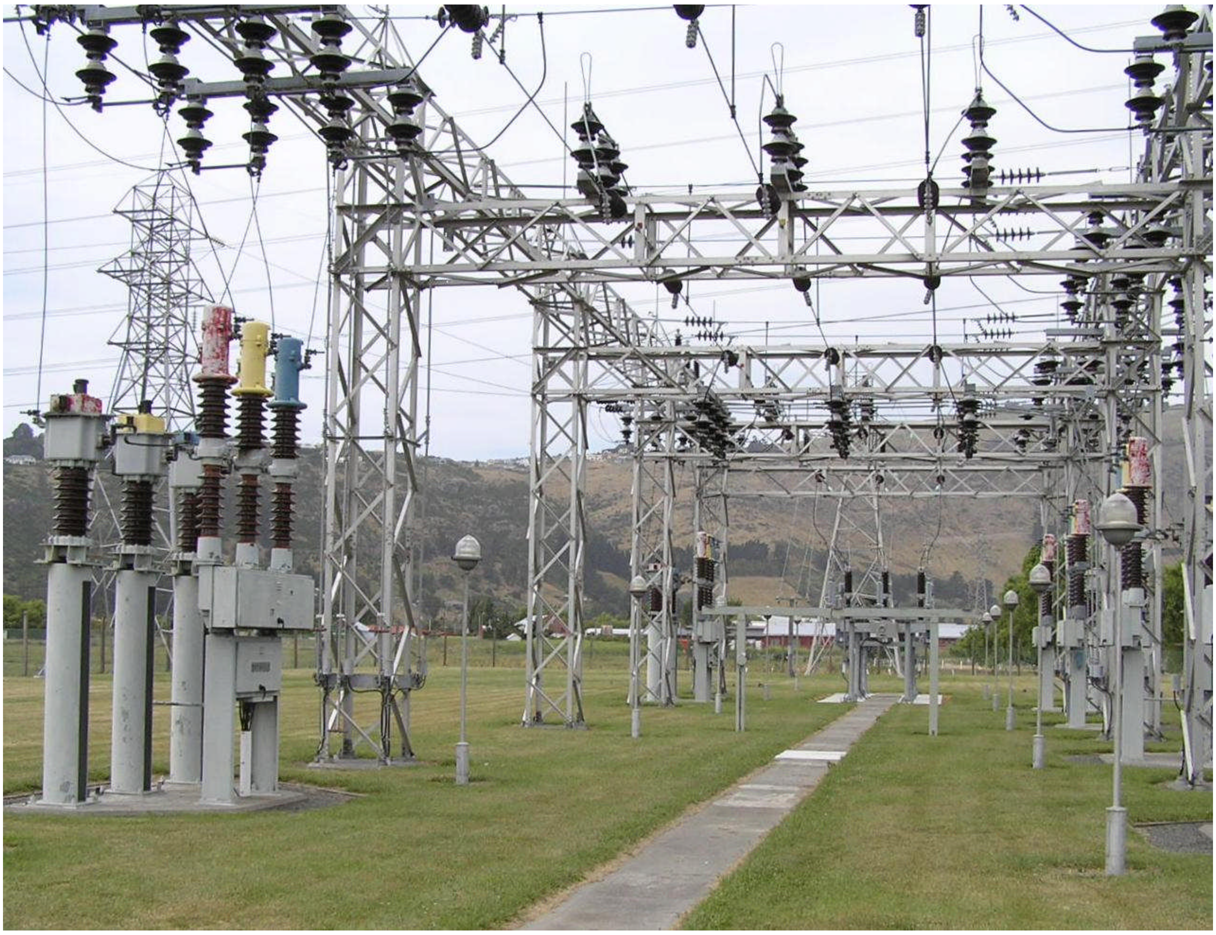
Figure 24: LV Overhead Lines Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	560	560	560	560	560	560	560	560	560	560
Total	**560**	**560**	**560**	**560**	**560**	**560**	**560**	**560**	**560**	**560**

The major component of our replacement expenditure is the pole replacement programme which is driven by the survey results.

Substations

Asset Management Report YE 2012



NW70.00.44

Table of Contents

1 INTRODUCTION

This document covers our substations and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service levels.

2 ASSET DESCRIPTION

2.1 GENERAL

Substations contain switching gear, transformers, protection and control equipment used for the distribution of electricity. In some cases they will have outdoor switchyards.

Each of the assets, including buildings and enclosures, that make up a substation are discussed in the documents below:

- *NW70.00.22* Protection Systems
- *NW70.00.23* Zone Transformers
- *NW70.00.24* Switchgear – HV and LV
- *NW70.00.33* Circuit Breakers – HV
- *NW70.00.34* Communication Systems
- *NW70.00.35* Control Systems
- *NW70.00.37* Load Management Systems
- *NW70.00.38* Metering
- *NW70.00.40* Distribution Transformers
- *NW70.00.41* Regulators
- *NW70.00.43* Network Related Property

This document covers the aspects of substations not covered in any of the documents above.

2.1.1 Zone substations

A zone substation is a major building substation and/or its associated high voltage structure/yard that has been identified as such because of its importance in our network. Orion has 53 zone substations and, in general, they include a site where one of the following takes place: voltage transformation of 66 or 33kV to 11kV, two or more incoming 11kV feeders from a Transpower GXP are redistributed or a ripple injection plant is installed. Zone substations are inspected every two months and given an infra-red scan every two years.

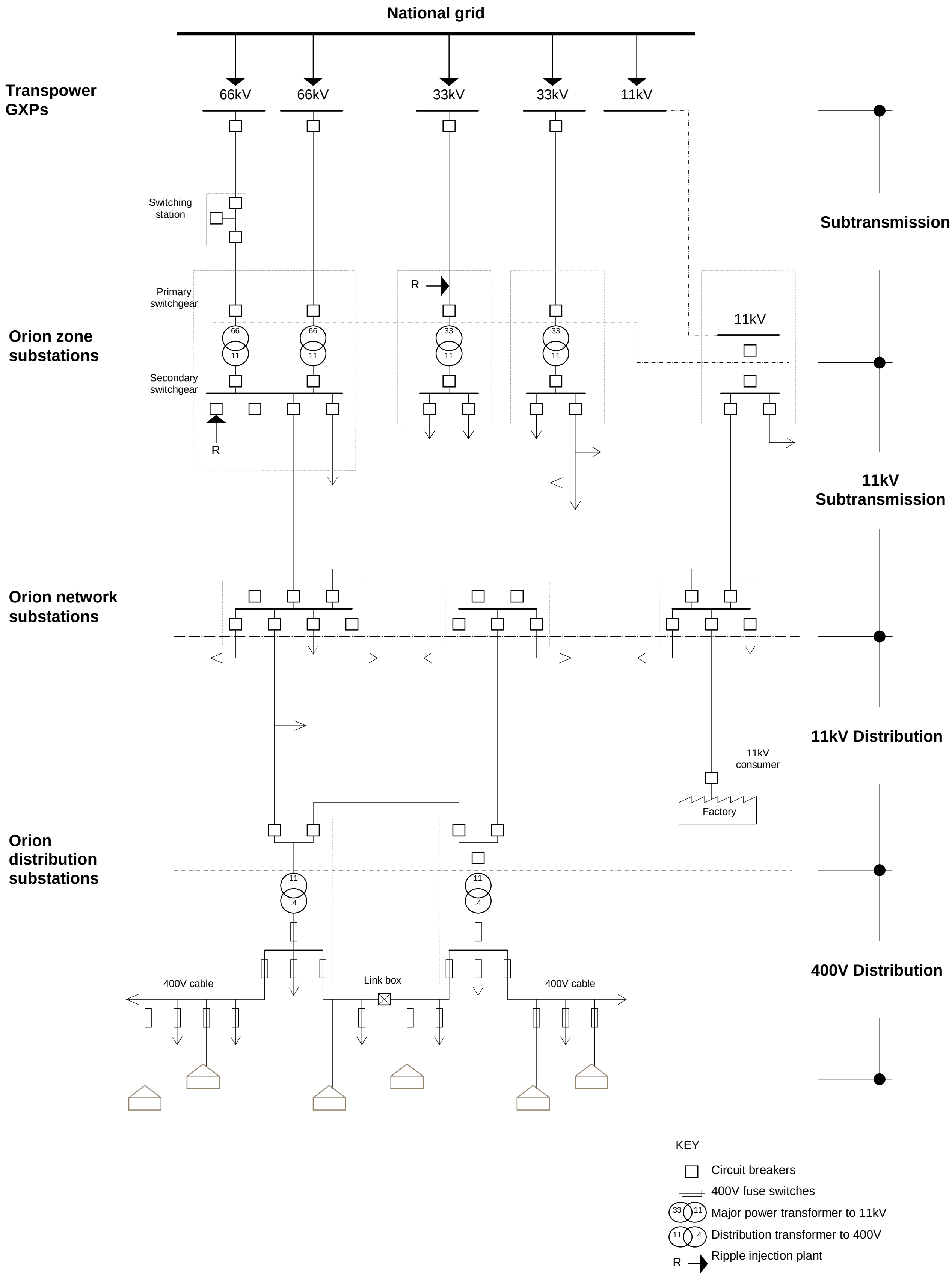
2.1.2 66/11kV zone substations

We have 21 66/11kV zone substations. Fifteen of them are in the Christchurch city urban area. Nine of the urban substations have an exposed bus structure. The largest structures are at Heathcote and Papanui. The Armagh structure is unique as it is constructed inside a building. We are currently building another indoor switchyard at McFadden's zone substation.

Figure 2: Construction Dates of Urban Switchyards

Structure	Year
Heathcote	1968
Papanui	1968
Halswell	1974
Barnett Park	1981
Lancaster	2000
Armagh	2001
Hawthornden	2004
Middleton	2008
Rawhiti	2011

Figure 1: Network Structure



Most of the urban zone substations are supplied by two cables connected to a pair of 66/11kV transformers. Each cable and associated transformer has an emergency rating equivalent to the full load of the zone substation (traditionally 40MVA) and can maintain supply should the other cable or transformer fail. The rating of the transformer and cable are currently limited by the thermal capacity of the 66kV cables. The transformers supply 11kV switchgear housed in two, three or four fire and explosion resistant switchgear rooms. This switchgear may supply up to 20 feeder cables and can be sectioned using bus-couplers between the switchgear rooms.

The six rural 66/11kV zone substations at Killinchy, Te Pirita, Greendale, Brookside, Dunsandel and Weedons are supplied by overhead lines and have 7.5/10 or 11.5/23MVA transformers. All have outdoor structures. The indoor 11kV switchgear may supply up to five feeder cables.

Three other substations at Larcomb, Highfield and Bankside have 66kV structures but currently operate at 33kV.

Figure 3: Weedons 66/11kV Zone Substation

2.1.3 33/11kV Zone Substations

Orion has 22 33/11kV zone substations, mainly in the rural area and on the western fringe of Christchurch city. Most have some form of outdoor structure and bus-work. We are replacing outdoor 33kV switchgear with an indoor type, negating the need for outdoor structures. Capacity of these substations is split into three groups as follows:

- Larger urban substations have two independent dual rated transformers. These have separate supplies, with each transformer and supply rated to carry the full substation load. The 11kV switchgear may supply up to 11 feeder cables and is housed in two switch-rooms linked by a bus-coupler.

- Smaller urban and larger rural substations have a pair of single rated transformers of 7.5MVA.

- Smaller rural substations have one single rated transformer of 7.5 or 2.5MVA. Single transformer zone substations (largely in rural areas) rely on back-up capacity from adjacent single transformer substations to provide firm capacity.

Figure 4: Bankside 33/11kV Zone Substation

2.1.4 11kV Zone Substations

We have 10 of these substations, all in the Christchurch city urban area. They are directly supplied by either three or four radial 11kV cables and do not have supply transformers. The cables have usually been laid along the same route and have sufficient capacity to supply the full zone substation load. The 11kV switchgear may supply up to 12 feeder cables and is housed in either two or three switch-rooms linked by bus-couplers.

None of the 11kV zone substations have any form of outdoor structure or bus-work.

Figure 5: Grimseys Winters 11kV Zone Substation

2.1.5 Network Substations

There are 248 network substations in our primary 11kV network, all are within the Christchurch urban area .They contain at least one 11kV circuit breaker per connected primary cable and one or more circuit breakers for radial distribution feeders. They may also contain secondary 11kV switchgear, one or more distribution transformers and an 800A or 1500A 400V panel with fuse assemblies using high rupturing current (HRC) links for local distribution.

Network substations have historically been installed whenever the load on radial feeders exceeded the design limit of cable capacity and when primary cables with adequate spare capacity were available nearby. The original policy was that no radial secondary loads were to be supplied from zone substations and all such loads were to be supplied from network substations. In recent years this policy has been modified so that if suitable spare switchgear is available at a zone substation, and it is more economical to do so, secondary cables may be laid from the zone substation to reinforce overloaded cables. This avoids the need for additional network substations.

Figure 6: Network Substation (Built in1930s)

2.1.6 Distribution Substations

A distribution substation can take the form of any of the types shown in the following table. They take supply at 11kV from either a zone substation, a network substation or from another distribution substation. In respect of the building substations, in many situations a consumer will own the building that houses our electrical equipment.

The types of substation that make up the total 10,673 substations in this asset category are shown in Figure 7.

Figure 7: Breakdown of Distribution Substations

Type	Number	Description
Building	283	These are similar to network substations in all aspects except for their status in the network. The substations vary in size and construction and 75% of the actual buildings are privately owned. All usually contain at least one transformer, with an 11kV 250MVA Magnefix switch unit (MSU) and 400V distribution panel containing fuse assemblies using high rupturing current (HRC) links.
Kiosk	2,835	Full kiosks vary in size and construction but all usually contain a transformer, up to 500kVA, with an 11kV 250MVA MSU and a 400V distribution panel containing fuse assemblies using HRC links.
Outdoor	557	These vary in configuration, but usually consist of a half-kiosk with 11kV switchgear and a 400V local distribution panel as per a full kiosk. An outdoor transformer is mounted on a concrete pad at the rear or to the side of the kiosk. This design allows the installation of a transformer up to 1000kVA.
Pole	6,242	Mainly single pole substations, usually with 11kV fusing and a transformer up to 200kVA. Some are a 2 pole structure (approximately 20) and may have a transformer of up to 300kVA installed.
Pad transformer	628	These are transformer only, mounted on a concrete pad and supplied by high voltage cable from switchgear/fuse at another site. Transformers are uncovered except for approximately 33 that are enclosed in a polythene or fibreglass cover.

Figure 8: Typical Outdoor Distribution Substation

2.1.7 Substation Earthing

A risk based approach has been taken for the inspecting and testing of our site earths. In general, earth systems in our rural area are subject to deterioration because of highly resistive soils, stony sub-layers of earth and corroded earthing systems. Between 2,000 and 2,600 sites are tested in any year and those sites requiring repairs are scheduled for remedial work in the following year.

3 ASSET PERFORMANCE

Figure 9: Zone Substation Capacity

Zone Substation	Circuit Breakers			Transformers		
	66kV	33kV	11kV	66kV	33kV	Rating (MVA)*
Annat	1	0	4		1	2.5
Armagh	5		33	2		20/40
Bankside	1		5		1	7.5/10
Barnett Park			12	1		11.5/23
Bishopdale			18			
Brookside	3	1	10	1	0	7.5/10
Dallington			26	2		20/40
Darfield		1	6		1	7.5
Diamond Harbour		3	4		1	7.5
Dunsandel	4		10	2		7.5/10
Duvauchelle		5	9		2	7.5
Fendalton			20	2		20/40
Foster			20			
Greendale	1		6	1		7.5/10
Grimseys Winters			18			
Halswell	8		11	2		11.5/23
Harewood		2	9		2	7.5
Harris			18			
Hawthornden			28	4		20/40 x2 and 11.5/23 x2
Heathcote	8		26	2		20/40
Highfield	1		6		1	7.5
Hills Road		1	5		1	7.5
Hoon Hay			26	2		20/40
Hornby		10	11		2	10/20
Hororata		2	5		1	7.5
Ilam			13			
Killinchy	3		6	1		7.5/10
Kimberley	3		11		2	7.5
Knox			21			
Lancaster	3		24	2		20/40
Larcomb	3		7		1	11.5/23
Lincoln		3	8		2	7.5
Little River		2	3		1	2.5
McFaddens			24	2		20/40
Middleton	2		19	2		20/40
Milton			28	2		20/40
Moffett Street		3	14		2	11.5/23
Montreal			18			
Motukarara		6	6		2	2.5 and 7.5
Oxford-Tuam			24	2		20/40
Pages Kearneys			16			
Papanui	10		36	4		30/36 x2 and 20/24 x2
Portman			18			
Prebbleton		2	8		1	11.5/23
Rawhiti	3		16	2		20/40
Rolleston		2	9		2	7.5
Shands Road		4	12		2	11.5/23
Sockburn		0	18		3	10/20 x2 and 11.5/23 x1
Spreydon			18			
Springston		4	6		1	7.5
Te Pirita	1		6	1		7.5/10
Teddington		1	3		1	2.5
Weedons	3		9	2		11.5/23 x2
Total in service	**51**	**52**	**736**	**37**	**31**	

Note: This table only shows equipment in service.

* Dual rated transformers have been installed with a design nominal rating/emergency rating.

Figure 9 details the capacity of each of our zone substations. We do not collate data for substation performance. Refer to individual asset management reports for performance and capacity detail of individual assets.

4 ASSET CONDITION

The general condition of our substations is very good, however we do not collate data for substation condition at this stage. Refer to individual asset management reports for asset specific condition information.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

Our substations are maintained and inspected as detailed in Figure 10.This involves a complete visual component inspection and the reading of any transformer loading maximum demand indicators (MDIs). Any minor maintenance is also done at this time and any larger maintenance work is reported back to the relevant asset manager.

Figure 10: Frequency of Substation Inspections and Maintenance

Substation Type	Inspection Frequency (months)	Major Maintenance Frequency (years)
Zone	2	4
Network	6	8
Distribution	6	8

Refer to the documents in Figure 11 for further information.

Figure 11: Technical Specifications

Reference	Name
NW72.23.18	Building Sub – Install Equipment
NW72.23.03	Distribution Sub – Inspection
NW72.23.05	Distribution Sub – Maintenance
NW72.23.02	Distribution Transformer – Maintenance
NW72.28.01	Earthing – Installation
NW72.28.02	Earthing – Testing
NW72.23.14	Kiosk Sub – Installation
NW72.23.04	Network Sub – Inspection
NW72.23.06	Network Sub – Maintenance
NW72.23.19	Network Substation – Seismic Strengthening
NW72.23.20	Pole Mounted Sub – Fuse Maintenance
NW72.21.21	Standard Construction Drawing Set – Substations
NW72.23.13	Zone Sub – Inspection
NW72.23.07	Zone Sub - Maintenance

5.2 SUBSTATIONS LIFECYCLE

We do not assign a service life to our substations. Refer to individual asset management reports for asset specific lifecycle information.

5.3 MAINTENANCE PLAN

The works for our substation maintenance is tendered out as part of our contracting model. For substations these works include:

- preventative maintenance on switchyard structures
- inspection rounds for both zone and network substations
- maximum demand Indicators (MDI) rounds
- updating substation manuals, drawing folders etc.

An allowance of $1.5m has been designated for the disestablishment of assets in the CBD and red-zone. These works, which are a direct result of the earthquakes, will primarily be driven by the requirements of the local authorities and CERA. We have forecast that the works will occur between 2013 and 2017, however as we gather more information and gain a clearer indication of timing from CERA we may amend the forecast expenditure and work programme as appropriate.

5.4 REPLACEMENT PLAN

We do not have specific replacement plans for our substations. If there is a significant change in local load conditions a review of the substations capacity will be undertaken to determine the next course of action.

We have a programme in place to convert all two pole substations to ground mounted substations. Two pole structures have poor resilience in seismic events. This programme was in place prior to the Canterbury earthquakes and is due to be completed in the next couple of years.

For asset specific replacement plans please refer to the documents listed in section 2.1.

5.5 DISPOSAL PLAN

We do not have a specific disposal plan for substations.

Due to changes in the location of load during their lifetime, substations may become under-utilised. In these cases, and when it is economical to do so, the cables supplying the substation may be through-jointed, the load transferred to other feeders and the substation decommissioned.

5.6 CREATION / ACQUISITION PLAN

The creation of new substations is driven by customer demand (load growth) and requires significant expenditure. Before spending capital on our network, we consider a number of options including those available in demand side management and distributed generation.

Other reasons for creating a new substation include:

- meet and maintain our security of supply standard (N-1)
- meet our reliability of supply targets.

5.7 RISK ANALYSIS

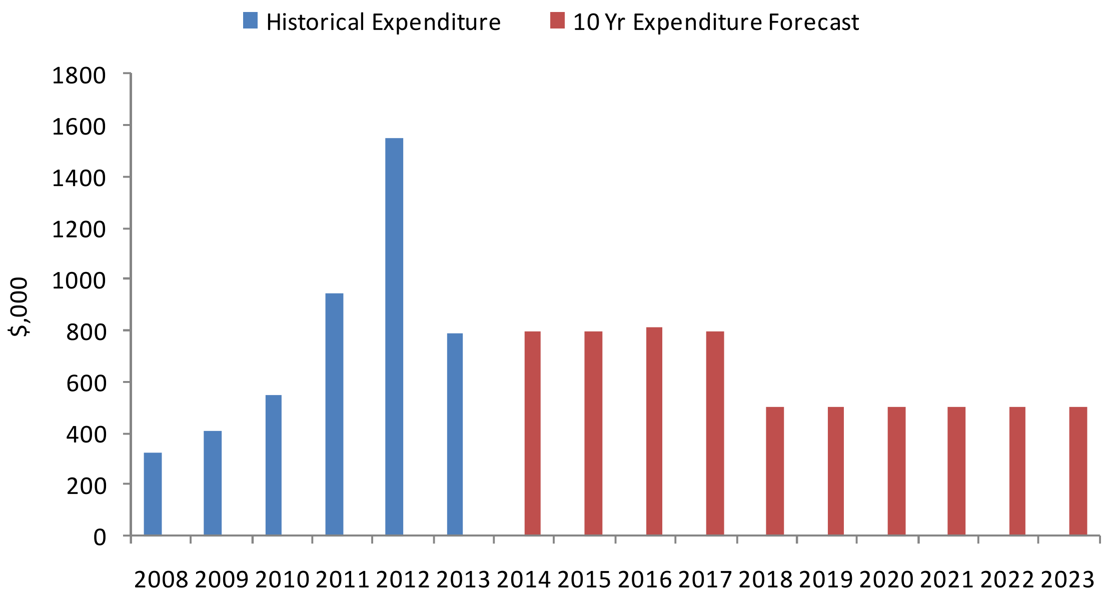
For details regarding risk management of our substations please refer to NW70:60:02 – Asset Risk Management Plan.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 12: Historical and Forecast Expenditure – Substations



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 13: Historical Substations Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	290	341	407	266	300	725
Non-Scheduled	1	34	71	27	23	40
Emergency	35	31	71	652	1228	25
Total	**326**	**406**	**549**	**945**	**1551**	**790**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

An allowance of $1.5m has been designated for the disestablishment of assets in the CBD and red-zone over the next five years. These works are a direct result of the earthquakes and are primarily driven by local authorities and CERA.

Figure 14: Substations Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	725	725	725	725	425	425	425	425	425	425
Non-Scheduled	40	40	40	40	40	40	40	40	40	40
Emergency	35	35	45	35	35	35	35	35	35	35
Total	**800**	**800**	**810**	**800**	**500**	**500**	**500**	**500**	**500**	**500**

Our scheduled maintenance is tendered out as part of our contracting model. There has been an increase to allow for the disestablishment of assets in the CBD and red-zone. As more information becomes available with regard to the quantity of assets to be removed along with the timeframe we will review the current forecasts and amend them as appropriate.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency works contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management (CDEM) Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

Figure 15: Historical and Forecast Expenditure – Earthing

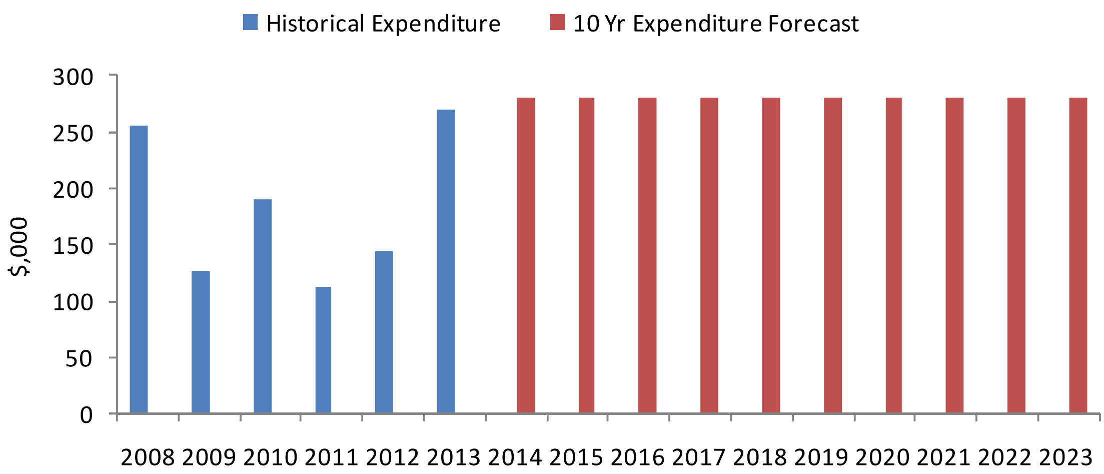


Figure 16: Historical Earthing Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	256	126	190	113	145	270
Non-Scheduled	0	1	2	3	4	10
Total	**256**	**127**	**192**	**116**	**149**	**280**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 17: Earthing Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	270	270	270	270	270	270	270	270	270	270
Non-Scheduled	10	10	10	10	10	10	10	10	10	10
Total	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**

Our scheduled maintenance for earthing is carried out as part of the wider substation maintenance programme. These works are tendered out as part of our contracting model.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency works contract.

We do not carry out permanent earthing works under our emergency works contract.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 18: Historical and Forecast Expenditure – Substations

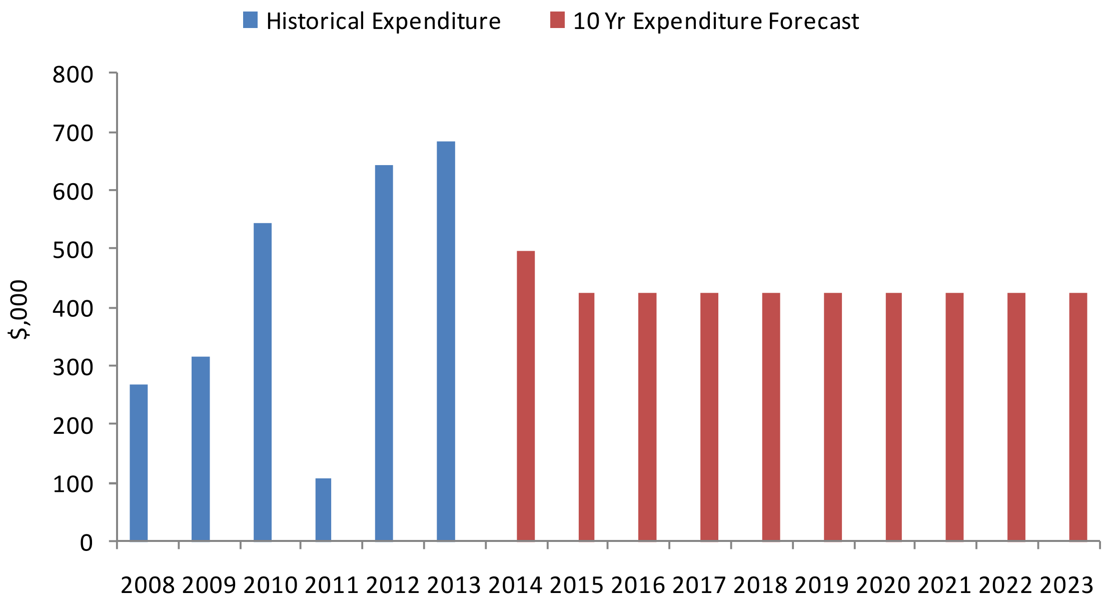


Figure 19: Historical Substations Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	267	317	545	108	605	685
Total	**267**	**317**	**545**	**108**	**605**	**685**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

The Canterbury earthquakes had an effect on our two-pole substation conversion programme in 2011 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 20: Substations Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	495	425	425	425	425	425	425	425	425	425
Total	**495**	**425**	**425**	**425**	**425**	**425**	**425**	**425**	**425**	**425**

The expenditure forecast for substations covers our:

- two-pole substation conversion programme
- seven-iron substation conversion programme
- replacement of battery chargers and other ancillary equipment in our zone and network substations.

Network Related Property

Asset Management Report YE 2012

NW70.00.43

Table of Contents

1 INTRODUCTION

We own a large amount of property and buildings which are solely used to house electrical equipment necessary for the operation and control of our electrical subtransmission and distribution networks. The buildings, known as substations, have been split into the following categories:

- zone
- network
- distribution - building
- distribution - kiosk.

This document covers each of our network property categories and details the criteria and asset management practices used to ensure we maintain acceptable levels of service from these buildings and kiosks.

Note: A substation contains multiple assets which are covered in other reports.

2 ASSET DESCRIPTION

2.1 GENERAL

Network related property covers all buildings, kiosks and land assets that form part of our electricity network.

Figure 1: Network Related Buildings and Kiosks

Building Type	Number	Age Range (yrs)	Operating Voltage
Zone substation	83	59 – 1	11kV, 33kV, 66kV
Network substation (Orion)	181	90 – 6	11kV
Network substation (Consumer)	58	89 - 2	11kV
Distribution building substation (Orion)	80	87 – 2	11kV
Distribution building substation (Consumer)	187	72 – 1	11kV
Distribution Kiosk	3528	70 - 1	11kV

2.2 ZONE SUBSTATION BUILDINGS

All of our zone substations, with the exception of Teddington, have buildings which contain switchgear and control equipment. We have a number of construction types as detailed in Figure 2 below.

Figure 2: Zone Substation Building Types

Construction Type	Number	Construction Date Range
Tilt slab	10	2007 – 2012
Concrete block	51	1953 – 2012
Modular	19	1972 – 1989
Relocatable	3	2007 – 2009

* Note: includes transformer enclosure buildings

Figure 3: Modular Concrete Construction – Bankside Zone Substation (1983)

Figure 4: Concrete Tilt Slab Construction – Papanui Zone Substation (2010)

Figure 5: Concrete Block Construction – Dunsandel Zone Substation (2008)

2.3 NETWORK SUBSTATION BUILDINGS

All of our network substations contain equipment used for the distribution of electricity. Of the 239 buildings utilised we own 181. The remainder are privately owned and are usually part of another building.

At the time of writing significant changes have been taking place in the CBD. As a result some of the privately owned buildings have been demolished leaving behind the substation only. Where appropriate we have reroofed and reclad these buildings to make sure they are weather proofed. The final make up of how many network buildings will remain in the CBD is unclear at this stage.

Figures 6-7: Alfred Street Substation – Before and After Surrounding Demolitions

Figure 8: Example of Reconditioned Re-clad Network Substation – Liverpool CFM Sub

2.4 DISTRIBUTION SUBSTATION BUILDINGS.

Similar to the network substation buildings Orion owns 80 of the distribution substation buildings currently being utilised on the network. There are 187 privately owned substations and they are generally part of another building within a customer's site.

With the continued changes within the CBD Red Zone and also in the eastern suburbs it is unclear at this stage how many distribution substation buildings will remain after site demolitions and relocations are complete. Where appropriate we have carried out any required work to these buildings to make sure they are secure and weather proof.

Figure 9: Example of a Privately Owned Distribution Substation – Davis Gelatine

Figure 10: Example of an Orion Owned Heritage Distribution Substation – Ferry Rd Woolston Park

2.5 DISTRIBUTION KIOSKS

We currently have 3,528 kiosks and transformer covers on our network housing equipment for the distribution of electricity. The kiosks are largely in good condition and fared reasonably well during the Canterbury earthquakes. The large majority of the kiosks are powder-coated steel and we also have 25 fibreglass/stone-chip kiosks. We are looking to initiate a plan to replace the fibreglass kiosks.

Recently we have developed a kiosk of concrete/steel construction. This kiosk type is generally used where a substation may be cut into sloping ground. There is currently two of this style kiosk in service.

Although not a kiosk there is also one underground transformer chamber with a quarter kiosk on the footpath for the HV switchgear. This chamber is outside Glandovey Rd No.88.

Figure 11: Kiosk and Transformer Cover Quantities

Construction	Full Kiosk	Half Kiosk	Quarter Kiosk	High Kiosk*	Fibreglass Kiosk*	Transformer Cover*	Grand Total
Total	2,078	478	260	653	21	37	3,528

* No longer manufactured.

See the following figures for examples of the various types.

Figure 12: Example of a Full Kiosk (Steel Construction)

Figure 13: Example of a Concrete/Steel Kiosk

Figure 14: Example of a Fibreglass Kiosk

Figure 15: Example of a Half Kiosk

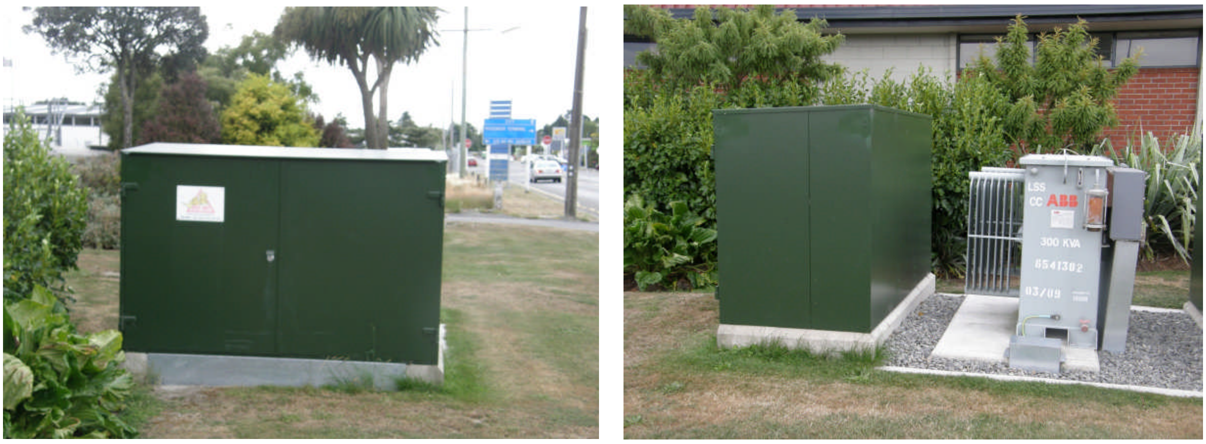


Figure 16: Example of a Quarter Kiosk

Figure 17: Example of a High Kiosk

Figure 18: Example of Fibreglass and Polythene Transformer Covers

3 PERFORMANCE

Our property assets must meet the following performance criteria:

- They must be secure. We are aware of increased public safety and risk management expectations surrounding our substations. A 10 year programme of upgrading security and safety is underway. This will mainly involve access (locks and gates/doors), fencing and earthing.

- They must be environmentally sound to ensure that the installed equipment is not compromised. The main areas of note here are the seismic strength and water-tightness of the buildings. Both these matters are being addressed.

- They must be visually acceptable. Work such as damage repair, ground maintenance, graffiti removal and painting is ongoing to achieve this outcome.

We undertook a 15 year programme to seismically strengthen our zone and network substation buildings. The results of this programme were encouraging given how well our substations performed during the Canterbury earthquakes.

3.1 IMPACT OF CANTERBURY EARTHQUAKES

The 4 September 2010 M7.1 earthquake, and subsequent M6.3 earthquakes in February and June 2011, caused minor superficial damage to a number of our substation buildings. Three zone substations incurred more substantial damage.

3.1.1 Greendale Zone Substation

Greendale is situated on the Hororata fault line and consequently some of the most significant ground movement was observed in the area after the September 2010 earthquake. The once level site shows signs of ground movement and is now slightly higher at one end than the other. All major foundations and the building appear to be structurally sound. The security fence was significantly affected but still secure. Whilst land around the building moved approximately 200mm, thus affecting water and drainage connections, the building itself remained level with very little damage. The sound engineering design and construction of this building meant it was ready for service within two days.

No further damaged occurred as a result of the February and June 2011 earthquakes.

3.1.2 Pages Switchyard

Pages had an outdoor switchyard and two associated buildings. It was subject to significant liquefaction and surface flooding after each of the three bigger earthquakes. The structures and buildings sunk into the ground, making the site unsuitable for continued use. It has been decommissioned and demolished.

This site is outside the red zone and therefore not subject to any offers from CERA. We are looking at options for this property.

3.1.3 Brighton Zone Substation

Brighton zone substation is situated across the road from Pages switchyard and near the Avon River. As a result of the February 2011 earthquake the site was subject to liquefaction and lateral spread. While the buildings and structures remained structurally sound they sank approximately 1m into the ground.

Due to this subsidence the site is no longer deemed suitable for a substation. A replacement zone substation (Rawhiti) was built in Keyes Rd. Brighton zone substation has been decommissioned and is currently being demolished. This site is within the red zone and the land is subject to an offer from CERA.

3.1.4 Distribution Substations

Across our network we observed only minimal damage to our distribution substation buildings and kiosks. The worst seismic damage occurred in the Sumner/Redcliffs area due to rock falls and landslides in the February 2011 earthquake. There was minimal extra damage after the June earthquake.

Figure 19: Wakefield Avenue North Substation

The building substations have had seismic strengthening, and generally we have observed in the worst cases movement of plaster between bricks and some cracking in floors and walls. We have observed significant subsidence around two building substations and several kiosks.

Figure 20: Network Related Property Performance

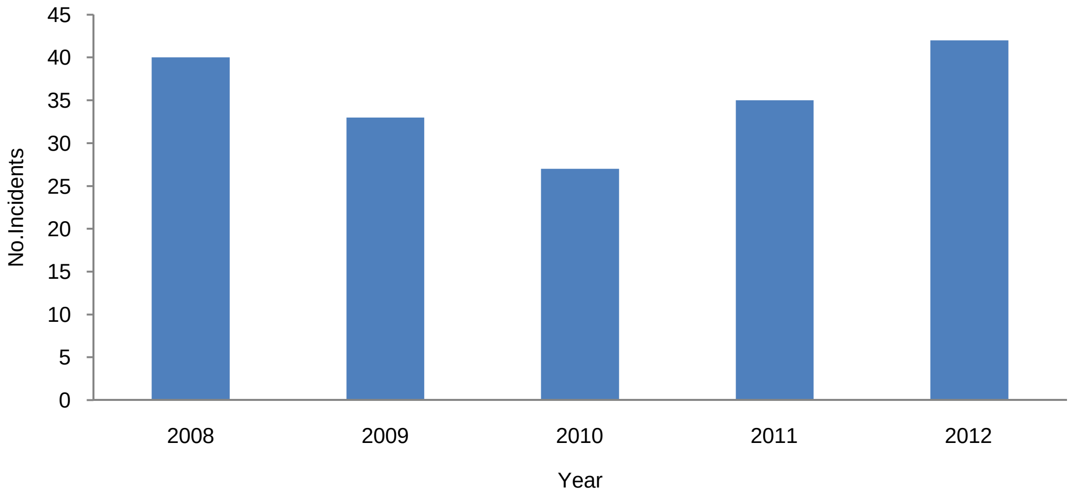
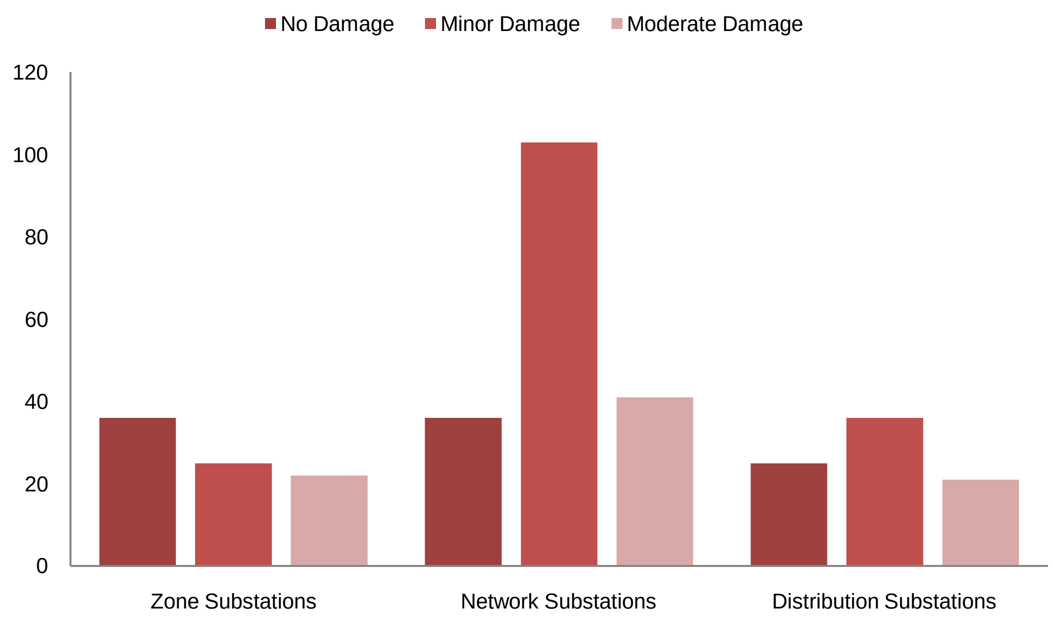


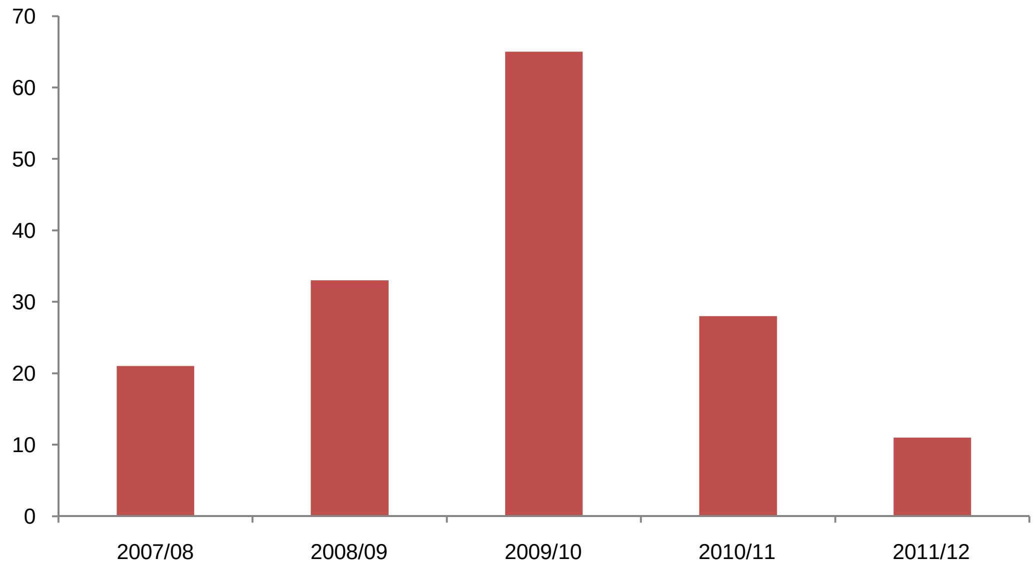
Figure 21: Extent of Damage to Substations after the Canterbury Earthquakes



We are currently working through a repair programme for our damaged substation buildings. An initial Level 1 site survey was initiated after the September and February earthquakes and we are now undertaking a Level 2 survey of the damaged sites.

The majority of work comprises crack repairs and injection followed by repainting damaged surfaces. Some site remediation works are required, especially fencing foundation repairs.

Figure 22: Substation Security Incidents (Open Substation/Kiosk Doors)



We are currently carrying out a lock replacement programme on all of our substations in order to minimise these security issues. The main causes of these security issues are:

- vandalism
- human error
- equipment failure/deterioration.

4 ASSET CONDITION

4.1 GENERAL

Our zone substation buildings are well designed and mostly constructed with reinforced and filled concrete blocks. The structural integrity of all the buildings has been inspected and remedial action taken to bring all zone substations up to the latest building code and related seismic strength code.

Our network/distribution building substations vary in both construction and age. Those constructed prior to the early 1960s are very brittle in nature, having walls constructed entirely of non-reinforced clay brick. Those that have been constructed since the mid-1960s are of a more substantial reinforced concrete framed masonry. A seismic assessment was undertaken on all our substations to determine those which required remedial work to bring them up to the current structural standard. A risk analysis of the resulting list concentrated on determining the consequences to the network of a loss of a given substation. This information was then used to develop our seismic strengthening programme, which was completed in 2009. There are a small number of distribution substations in Orion owned and consumer owned buildings that have not yet had remedial works undertaken. The future of these buildings is unknown at this stage. We are coordinating the CBD rebuild with the local authorities and will carry out assessments on a case by case basis as appropriate.

Our kiosks are generally in reasonable condition. Steel kiosks in the eastern suburbs nearer the sea are prone to some corrosion and it is expected that these kiosks will have to be replaced much sooner than those in the remainder of our network. They are being attended to as required. We have 25 kiosks of a fibreglass/stone chip construction and these have been the subject of a detailed inspection to assess their condition and possible replacement.

We are currently over half way through a programme to seismically strengthen or remove any two-pole and single-pole substations with large heavy transformers.

4.2 HISTORICAL ISSUES

The major issue of significant historical importance to our network property has been the series of earthquakes that occurred in 2010 and 2011. To ensure the resiliency of our network and lessen the impact of any future earthquakes we are currently formulating a Connection Guide for customers requiring a network connection. This guide will be used to ensure that the following requirements are met:

- substation shall be above ground, i.e. no basement substations
- clear access to substation at all times for emergency and maintenance personnel
- substation to be accessible from the street.

Other long standing issues that we have with our network property are:

- The ongoing problem of graffiti and posters. We are now installing ribbed doors on our kiosks in an attempt to discourage this activity. With ENI Engineering we investigated products to assist in the safe and effective removal of the graffiti. However to date we have had little success.
- Security/ Access issues. To minimise the risk to the public of exposure to live equipment, we are undertaking a programme to upgrade site security. There is also a plan in place to improve and standardise the security fencing around our zone substations to include an outer boundary fence around the perimeter of the site with an inner security fence protecting the switchyard and substation building. We are also part way through a four year programme to replace all of our locks with a standard Abloy lock.
- The ingress of moisture to our substations can compromise the performance of our equipment. Often this is because of blocked gutters or roof leaks. We have now included the cleaning of gutters within our grounds maintenance contracts to help resolve this issue. We are also currently working towards creating a plan to determine any roofs that require replacing.
- Site signage UV damage. Given their exposure to the elements we have issues with our on-site signage fading after prolonged UV exposure. We are working with our signage suppliers to develop and integrate a product that will resolve this problem.

4.3 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011, EA Technology Ltd was engaged to develop Condition Based Risk Management (CBRM) Models for a number of our asset classes. Our network buildings were not included in this project.

In an effort to better record the condition of our zone substation buildings, we are developing an asset ranking system. This system was used for other assets prior to CBRM being introduced. We have developed ‘condition assessment’ sheets for each building (including transformer enclosures). Over time we will populate these sheets and use them as the basis for our ongoing maintenance and renewal plans. Once this process has been fully implemented and working, we will undertake a review to determine if there are any benefits to creating a CBRM model for these assets. Refer to Appendix A for an example of a condition assessment sheet.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

The purpose of Orion’s asset management practices is to ensure that our network property is managed in a manner that is consistent with Orion’s corporate obligations to deliver effective and efficient services. We use several databases to monitor the maintenance and performance of the substations such as our Asset Register (WASP) and our Works Management system. We also use a Fault Incident Report database to collect any faults or security issues.

For any instances where further expertise is sought we will employ an external consultant to offer an independent judgement to assist in the decision making process for any maintenance or replacement programmes.

While our safety and seismic strengthening risk reviews and subsequent works have been quite targeted, the rest of our maintenance and renewal programmes have been reactionary. With the recent changes to the property team, we are moving to a more proactive approach in line with how we carry out works on the other network assets.

5.2 PROPERTY (NETWORK) LIFECYCLE

We have no assigned end of life age for our building substations. Our maintenance programme ensures that we maintain these assets to provide the required levels of service. We will continue to monitor and repair the substation buildings to ensure that they do not deteriorate further as a result of the recent seismic activity.

Figure 23: Age Profile - Zone Substations (83)

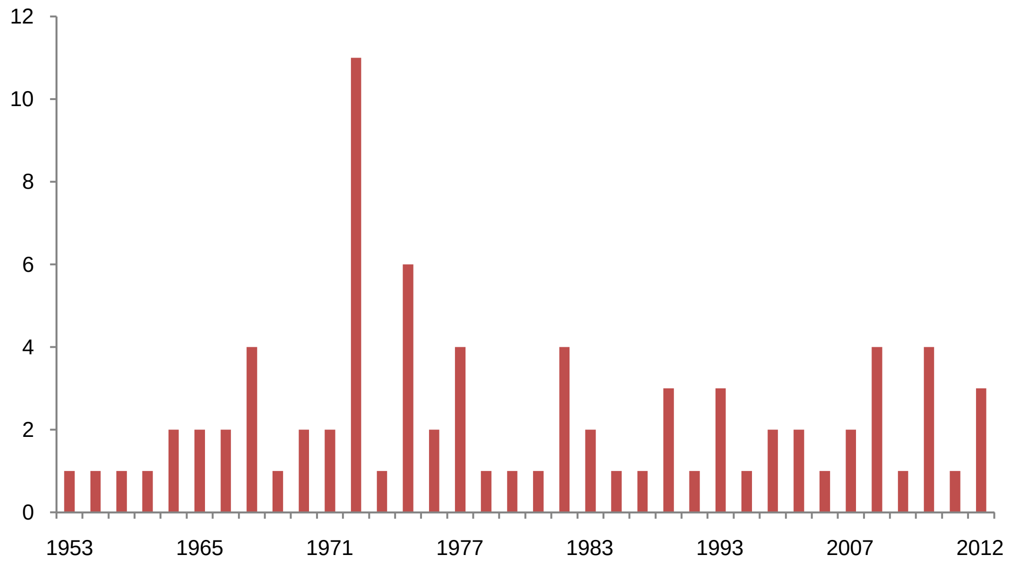


Figure 24: Age Profile - Zone Substation Buildings

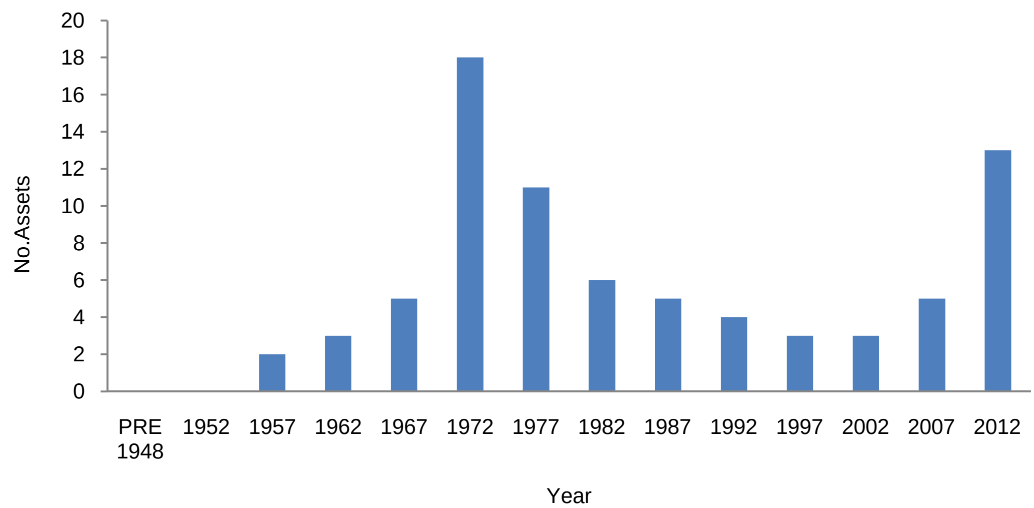


Figure 25: Age Profile - Network Substations

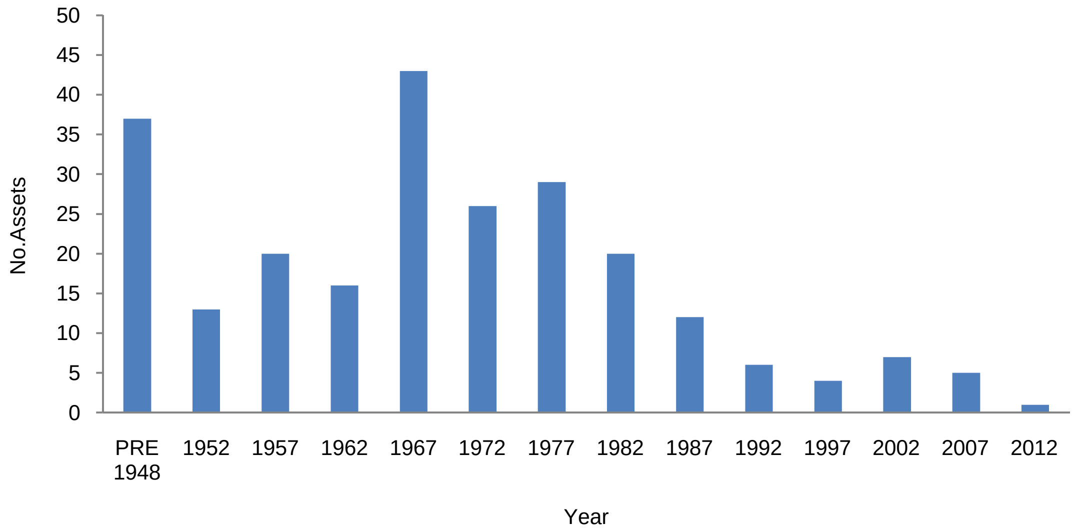


Figure 26: Age Profile - Kiosks

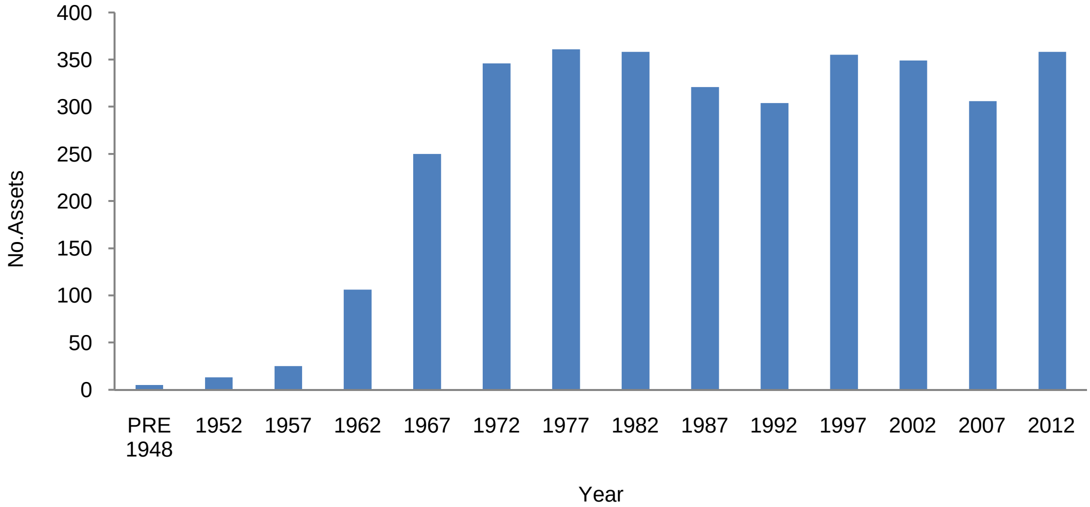


Figure 27: Age Profile - Distribution Building Substations (Orion owned)

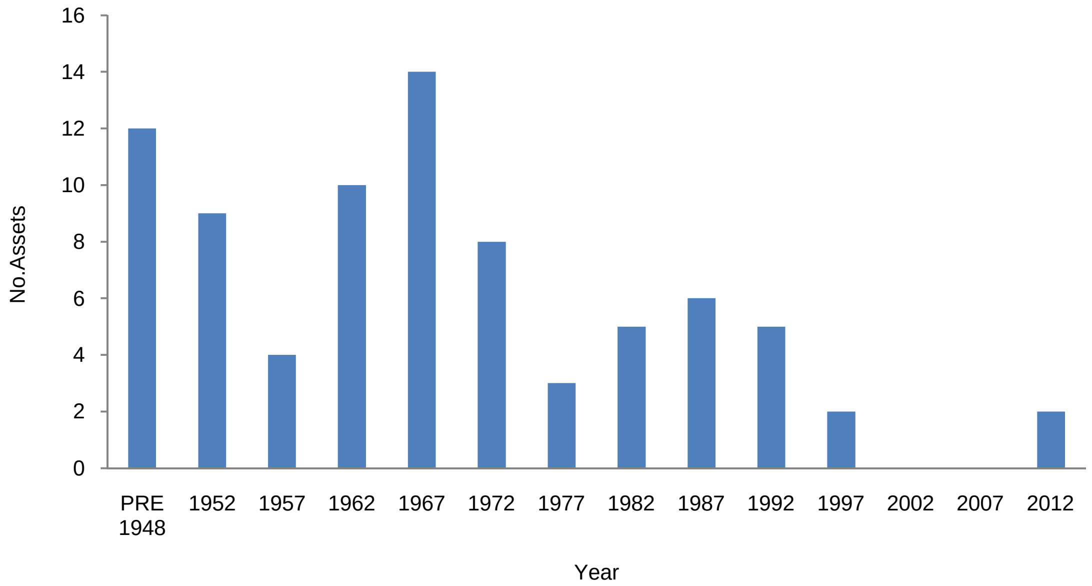
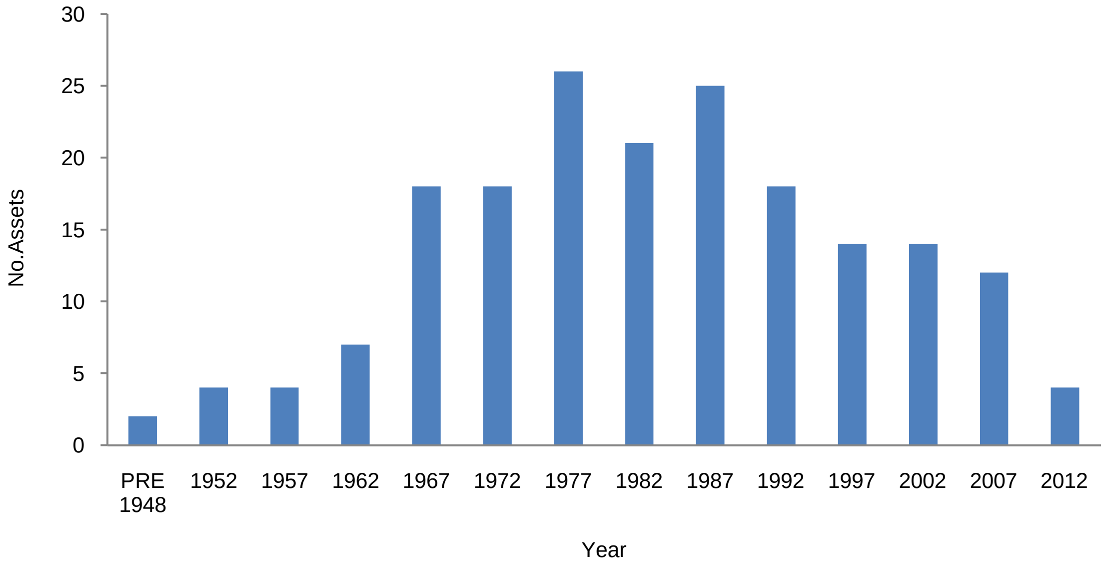


Figure 28: Age Profile - Distribution Building Substations (Owned by others)



5.3 MAINTENANCE PLAN

A five year maintenance plan has recently commenced with the view to repair all of our buildings which have suffered earthquake damage. All our buildings and land are inspected regularly, and minor repairs are undertaken as they are identified. Major repair and maintenance work is scheduled, budgeted for and undertaken on an annual basis.

Property maintenance is expected to remain at a constant level, although many of the older consumer owned substations will require seismic upgrading over time if they are retained. Consumer owned substations that require maintenance or strengthening to remove risk to our equipment may present some problems in relation to who will bear the cost of this work. These will be assessed on a case by case basis.

Upgrading is underway on some of our rural zone substation buildings constructed in modular concrete sections with predominantly steel framed glass ends. The ends are being replaced with about two-thirds solid wall, with aluminum doors and windows. This will help with weather tightness and security.

Our substations are maintained on an as-required basis, with most general maintenance work identified during six-monthly inspections. Work such as damage repair, ground maintenance, graffiti removal, painting, signage and lock replacement is ongoing.

A number of our substation buildings were constructed with a flat concrete roof with a tar-based membrane covering. These have been prone to leaking when cracks develop in the concrete. Over the past few years we have implemented a programme to upgrade these buildings by constructing a new pitched Coloursteel roof over the top. We expect to have covered all of the original flat concrete roofs within the next few years.

Some of the older kiosk foundations have moved due to surrounding land movement. They need to be levelled to relieve stress on the attached cables. A small number of them are being attended to each year.

We maintain and repaint our kiosks as required with more focus to deter rust on the coastal areas. Buildings are repainted approximately every 10 years and we are now using a silicon based product to provide a waterproof membrane and protect the substation from water ingress through the block work.

Graffiti is an ongoing problem at virtually all of our sites. We remove it as soon as possible after it is reported. We liaise with the local councils and community groups in our area to assist us with this problem. Orion now has a specific email set up graffiti@oriongroup.co.nz were members of the community can report graffiti. We aim to attend to graffiti within 48 hours.

5.4 REPLACEMENT PLAN

We don’t have a replacement plan for our building subs. These assets are maintained to ensure they provide the required level of performance. However, we have allowed for major building upgrades in 2019 and 2021 but these are dependent on the purchase of some of Transpower’s spur assets.

There is a programme to replace any fibreglass kiosks as well as those steel kiosks close to the coast. We are also in the process of formulating a roof replacement programme.

Allowance has been made for upgrading security fencing and seismic requirements.

5.5 DISPOSAL PLAN

Equipment is disposed of as part of the replacement programme. In the past old substation buildings (circa 1930s) have been sold when they are no longer required.

We are currently engaged in justifying continued ownership of (or easements over) all unused sites. We will relinquish ownership of sites deemed not required.

5.6 CREATION / ACQUISITION PLAN

We construct new buildings and kiosks to meet consumer demand for supply to subdivisions or commercial ventures and when necessary to place overhead reticulation underground.

We are investigating the ownership of leased/rented sites with the view to create a more secure tenure of all network land, if required.

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.9 RISK ANALYSIS

The risks that our network buildings are exposed to are listed below and rank with no sequential importance:

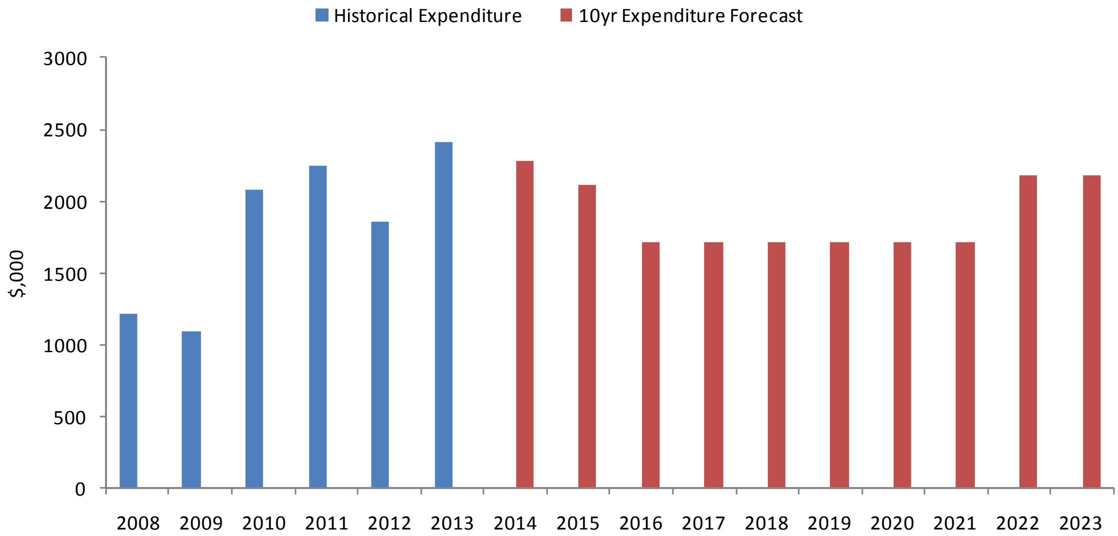
- *Seismic movement* – we have undertaken to seismically strengthen all building substations
- *Liquefaction*
- *Defective drainage*, guttering - grounds maintenance contracts now cover the clearing of drains and gutters
- *Roof leaks* - roof replacement programme to be initiated
- *Vegetation/tree roots* - removal or maintenance of large trees/shrubs in close proximity to our substations as a variation to our grounds maintenance contracts
- *Vandalism* - repairs carried out as soon as incident is reported
- *Rust* - replacement programme in place for kiosks situated in close proximity to the coast.
- *Subsidence*
- *Extreme weather conditions*
- *Fire* - smoke detectors installed in zone substation buildings.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 29: Historical and Forecast Expenditure – Buildings



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 30: Historical Buildings Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	795	1099	1335	1204	635	2215
Non-Scheduled	196	213	197	459	151	200
Emergency	0	0	0	0	0	0
Total	**991**	**1312**	**1532**	**1663**	**786**	**2415**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

Figure 31: Buildings Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	2080	1910	1510	1510	1510	1510	1510	1510	1510	1510
Non-Scheduled	200	200	200	200	200	200	200	200	200	200
Emergency	0	0	0	0	0	0	0	0	0	0
Total	**2280**	**2110**	**1710**	**1710**	**1710**	**1710**	**1710**	**1710**	**1710**	**1710**

Our scheduled maintenance is carried out as part of the wider substation maintenance contract which is tendered as part of our contracting model.

Our non-scheduled maintenance forecast is for unknown issues that may occur but would not be carried out under the emergency contract.
Our emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

Figure 32: Historical and Forecast Expenditure – Grounds

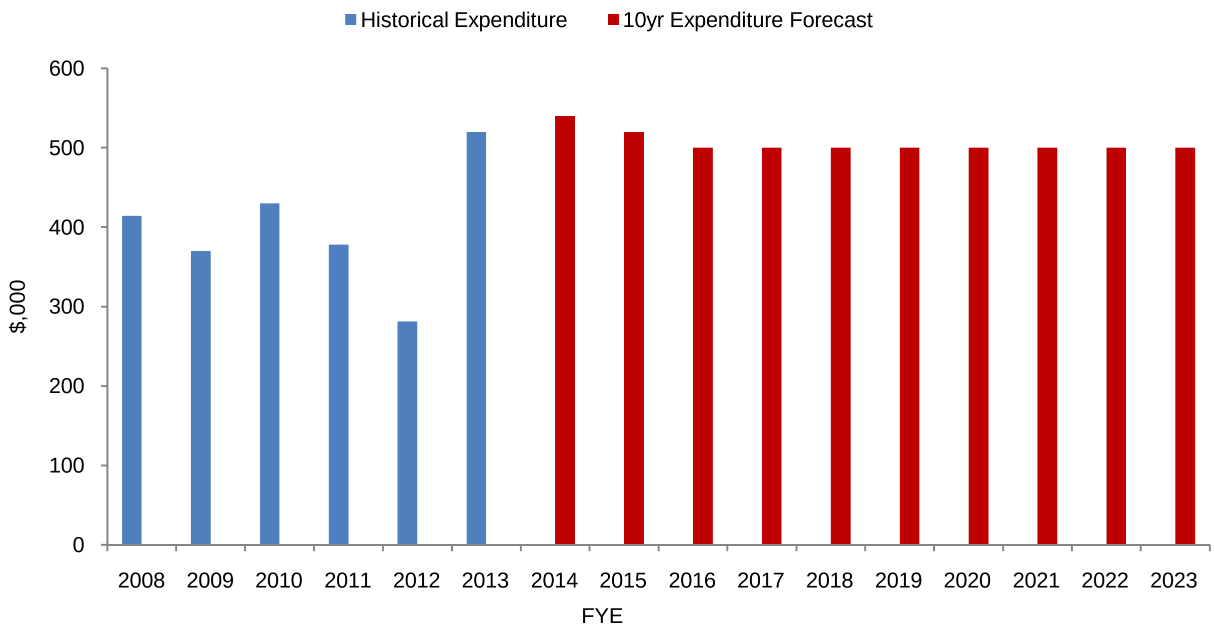


Figure 33: Historical Grounds Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	261	257	217	171	153	410
Non-Scheduled	154	113	213	207	128	110
Emergency	0	0	0	0	0	0
Total	**415**	**370**	**430**	**378**	**281**	**520**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

Figure 34: Grounds Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	430	410	390	390	390	390	390	390	390	390
Non-Scheduled	110	110	110	110	110	110	110	110	110	110
Emergency	0	0	0	0	0	0	0	0	0	0
Total	**540**	**520**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 35: Historical and Forecast Expenditure – Buildings

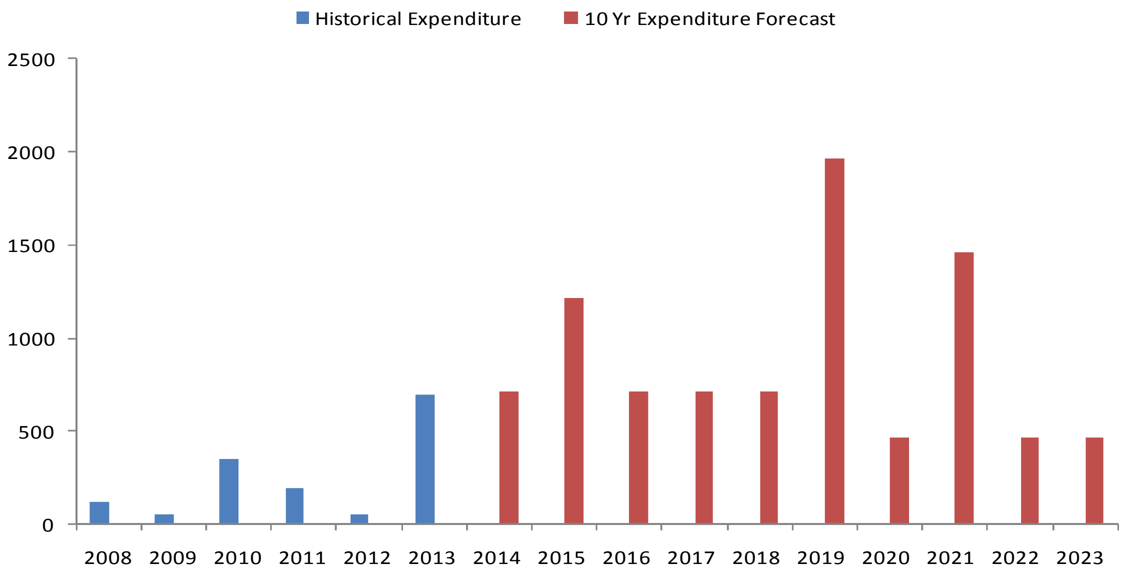


Figure 36: Historical Buildings Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	118	53	475	186	55	700
Total	**118**	**53**	**475**	**186**	**55**	**700**

At the time of writing, the budgeted rather than actual expenditure figures for 2013 were used.

Figure 37: Buildings Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	715	1215	715	715	715	1965	465	1465	465	465
Total	**715**	**1215**	**715**	**715**	**715**	**1965**	**465**	**1465**	**465**	**465**

Our replacement expenditure is based on our kiosk replacement programme and seismic upgrades to Orion owned and privately owned distribution substations. There is still uncertainty as to how many of these will be retained in the CBD, therefore we will review these forecasts as new information comes to hand.

APPENDIX A - CONDITION ASSESMENT SHEET

Site	Annat
Construction Type	Modular
Site Number	KO12/67
Sub Designation	Zone Sub
Sub Rating (MVA)	2.5
Primary Volt (kV)	33
Current FY	2013
Construction Date	1981
Roof Reclad	NA
Seismic Upgrade	2000
Age (yrs)	32
No. Customers (approx)	516

Building Condition Assesment - Annat - KO12/67

Building Sections		Specific Factors	Weighting	Score (/10)	Total	Comments
Roof	25	Roof	15	8	12	Cleaning required
		Gutters	10	NA	10	
Security	30	Surrounding Fencing	10	10	10	
		Doors	10	10	10	
		Locks	10	10	10	
Safety	20	Trench Plates	5	NA	5	
		Barriers (if required)	10	NA	10	
		General	5	10	5	
Construction	25	Strengthening	5	10	5	
		General Condition	20	8	16	Modular construction has leaked in the past
				Total Score	93	

66kV Underground Cables

Asset Management Report YE 2012

NW70.00.32

Table of Contents

1 INTRODUCTION

This document covers Orion's 66kV underground cable categories, oil-level monitoring system, and details the criteria and asset management practices used to ensure effective lifecycle performance and acceptable service life.

2 ASSET DESCRIPTION

2.1 GENERAL

There are two types of 66kV underground cable in Orion's network, namely self contained oil-filled (SCOF) 3 core aluminium cables and XLPE single core copper cables. These subtransmission 66kV cables total 49km in length.

2.1.1 Self contained 3 phase oil-filled cables

There is 41km of oil-filled cable in Orion's network. Traditionally a pair of radial SCOF 3 core 300mm^2 Al, corrugated Aluminium sheath cables were installed to supply many of our 66kV/11kV zone substations.

These cables are encased in a weak-mix concrete (600mm wide by 300mm high) and capped by a 75mm layer of hard concrete dyed red. For each zone substation, the two cables have been spaced 300mm apart in a common trench at a minimum depth of 750mm.

2.1.2 Single core XLPE cables

In 2000-2002, a circuit of three single core 1600mm Cu, XLPE cables was installed from the Bromley GXP to Lancaster and Armagh zone substations to reinforce the upper network into the CBD. This was the first 66kV circuit of XLPE type cables and has since become Orion's standard for 66kV projects, moving away from SCOF cables.

The 7.2km of 3 single core 1600mm^2, Copper XLPE cable has been installed in a weak mix of thermally stabilised concrete and capped with a 75mm layer of stronger concrete that has been dyed in red colour. Two fibre optic cables have been installed with the 66kV cables, one of which is strapped to the 66kV cable to facilitate monitoring of thermal performance. The second fibre optic cable is part of the cable protection system.

Additionally, short lengths of 66kV 3 single core cable are located within the zone substations to interlink primary equipment, switchgear and overhead lines.

In 2008, Orion installed 66kV cables to connect our upgraded Middleton zone substation to Transpower's 66kV overhead lines. These double circuit cables are XLPE and each cable has an emergency rating equivalent to the full load of the zone substation (nominally 40MVA).

Figure 1: Oil-filled 66kV Underground Cables

Cable Location	Cable Type	Manufacturer	Total Cable Length (km)	Installation Date	Age
Addington – Armagh	2 x 3C, 300mm^2 Al	Pirelli	8.8	1981	31
Addington – Fendalton	2 x 3C, 300mm^2 Al	Hitachi	4.8	1978	34
Addington – Milton	2 x 3C, 300mm^2 Al	Hitachi	8.0	1979	33
Addington – Oxford-Tuam	2 x 3C, .45" Al	Dainichi	5.2	1974	38
Halswell – Hoon Hay	2 x 3C, .45" Al	AEI	5.3	1969	43
Papanui-McFaddens	2 x 3C, .45" Al	Dainichi	8.2	1972	40

Figure 2: XLPE 66kV Underground Cables

Cable Location	Cable Type	Manufacturer	Total Cable Length (km)	Installation Date	Age
Bromley – Lancaster	3 x 1C, 1600mm^2 Cu	Olex	15	1999	13
Lancaster – Armagh	3 x 1C, 1600mm^2 Cu	Olex	7.5	2000	12
Middleton GXP – Middleton Tx	3 x 1C, 300mm^2 Cu	Olex	0.8	2008	4

3 ASSET PERFORMANCE

3.1 GENERAL

The 66kV underground cables are predominantly 300mm^2 Al (paper insulated, oil filled and Aluminium sheathed) with a nominal rating of 425A or 48.5MVA @85^{0}C. Each cable has an emergency rating equivalent to the full load of the zone substation (nominally 40MVA). The Bromley-Lancaster-Armagh cable is a 1600mm^2 Cu XLPE lead-sheathed cable with a design rating of 1400A or 160MVA @90^{o}C. This rating allows for the contingency of a loss of supply at the Addington GXP, and enables the Christchurch CBD and surrounding areas to be supplied from the Bromley GXP.

Orion measures the performance of the 66kV cables based on many different benchmarks such as SAIDI, SAIFI and fault incident records. According to records of fault incidents, the failure modes have predominately related to:

- third party damage, for example interruption of other services trenching
- terminations issues such as oil leaks
- differential ground settlement that can occur as a result of poorly compacted fill material or naturally soft ground for example organic clays and peat
- movement as a result of an earthquake (as observed during the 2010/2011 earthquakes).

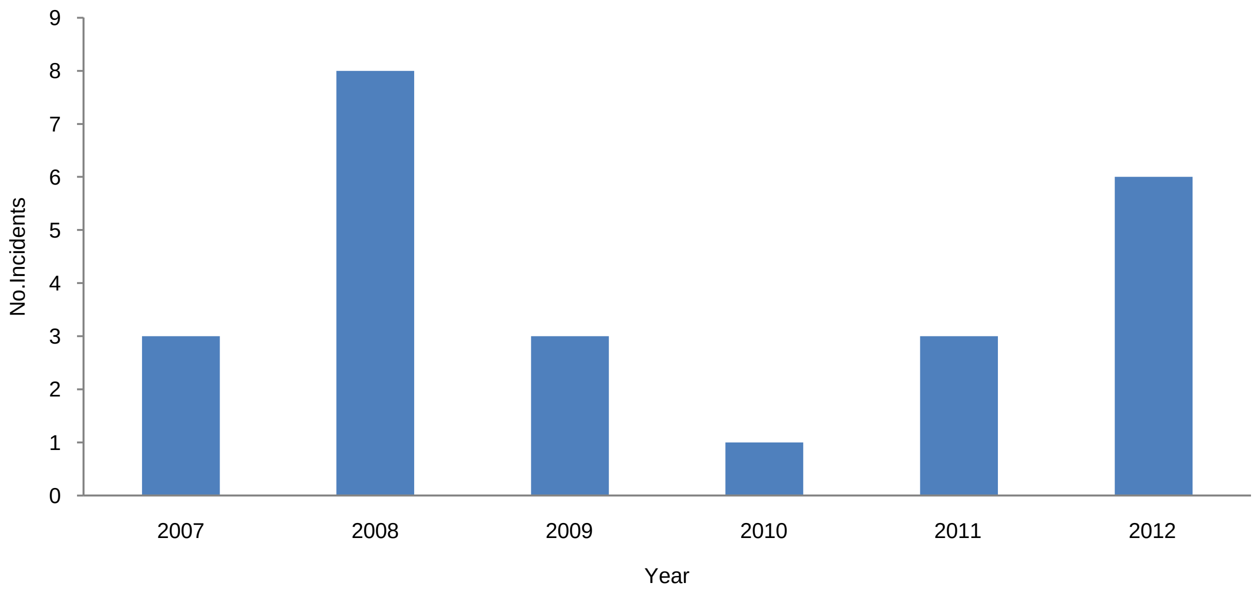
The cable routes have been assessed to ascertain their vulnerability to a seismic event.

To manage all possible risks, especially with the recent Canterbury earthquakes, we are currently developing plans to repair, replace or diversify our assets. We are currently developing strategies as to where new cables in the eastern suburbs should be run and what bridges need to be reinforced for river crossings.

Figure 3: Number of 66kV Underground Cable Fault Incidents Per Year

	2007	2008	2009	2010	2011	2012	Total
Number of Faults	3	9	3	1	3	6	**25**

Figure 4: Number of 66kV Underground Cable Fault Incidents Per Year



4 ASSET CONDITION

During the Canterbury earthquakes, there was significant ground movement in areas around the Avon River where our Brighton and Dallington 66kV cables traversed. An inspection was carried out on the Dallington cables after the September 2010 earthquake and while there was some minor damage, the cables were returned to service within a lower load rating.

The M6.3 aftershock in February 2011 caused further significant damage to the Brighton and Dallington 66kV cables and some of our other 66kV subtransmission cables in our urban network, particularly in the eastern side of the city. The cables to Brighton and Dallington zone substations could not be recovered and made serviceable and have been written off.

Temporary 66kV overhead lines have been installed to provide supply to Dallington zone substation and the new Rawhiti zone substation. We have consent for these lines for three years and are currently looking at long term solutions for the recovery of the network in the north east, to its pre-earthquake reliability.

4.1 GENERAL

Our 66kV cables have a low average age, with the oldest cables being laid in 1967. The cables to date have been operated conservatively and therefore have not been subject to electrical aging mechanisms. We have monitored the cables to ensure the integrity of the mechanical protection of the cables is maintained.

All the original 66kV British designed and Japanese Hitachi oil filled cable joints that indicated excessive movement of conductors within the joints have now been replaced.

The Dainichi joints have so far shown no signs of damage or buckling and have been assessed as being a low risk of failure due to thermal expansion/movement of conductors. We will continue to inspect the Japanese-designed Dainichi oil filled cable joints as part of an ongoing maintenance plan.

The reinforcement of joints on 66kV circuits to Armagh, Brighton, Dallington, Fendalton, Hoon Hay and Milton zone substations have now been completed.

Regular sheath testing is being carried on all 66kV cables to monitor the integrity of the cable sheath and insulation from earth. The following table provides recent sheath testing results.

Figure 5: Sheath Testing Results (03/2012)

Location	Sheath Tests		
	Current (mA)	Voltage (kV)	Test Date
Halswell - Hoon Hay T1	10.0	4.95	01/2012
Halswell - Hoon Hay T2	0.5	5.00	02/2012
Addington - Fendalton T1	50.0	0.75	10/2011
Addington - Fendalton T2	50.0	0.51	10/2011
Addington - Milton T1	50.0	0.60	10/2011
Addington - Milton T2	50.0	0.72	08/2011
Addington - Oxford-Tuam T1	50.0	0.10	12/2011
Addington - Oxford-Tuam T2	50.0	0.39	12/2011
Papanui - McFaddens T1	1.4	5.00	10/2011
Papanui - McFaddens T2	50.0	0.05	10/2011
Bromley - Lancaster (Red)	50.0	0.20	03/2012
Bromley - Lancaster (Yellow)	50.0	0.60	03/2012
Bromley - Lancaster (Blue)	50.0	0.10	03/2012
Lancaster - Armagh (Red)	1.9	5.00	02/2012
Lancaster - Armagh (Yellow)	1.9	5.00	02/2012
Lancaster- Armagh (Blue)	1.4	5.00	02/2012

The purpose of these tests is to determine the soundness of the outer protective sheath against water ingress, mechanical damage and to allow for partial discharge testing.

The sheath test consists of applying 5kV (AC for SCOF and DC for XLPE cables) to the cable sheath for 1 minute. The leakage current is then measured but not allowed to exceed 50mA to avoid any further damage to the outer insulation. If the leakage current exceeds 50mA the voltage is then reduced to obtain a measurement at 50mA.

In the interim alarms will warn of low oil pressure and levels via the SCADA system and we will install pressure transducers at the cable ends.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our 66kV underground cable population. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual underground cable and joint. This effectively gives the assets a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Figure 6: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 7: Year 0 66kV Underground Cable Health Index Profile

Category	Number of Assets
(0-1)	8,230
(1-2)	2,065
(2-3)	31,182
(3-4)	21,840
(4-5)	0
(5-6)	0
(6-7)	0
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	0
Total	**63,317**

Figure 8: Year 0 66kV Underground Cable Heath Index Profile

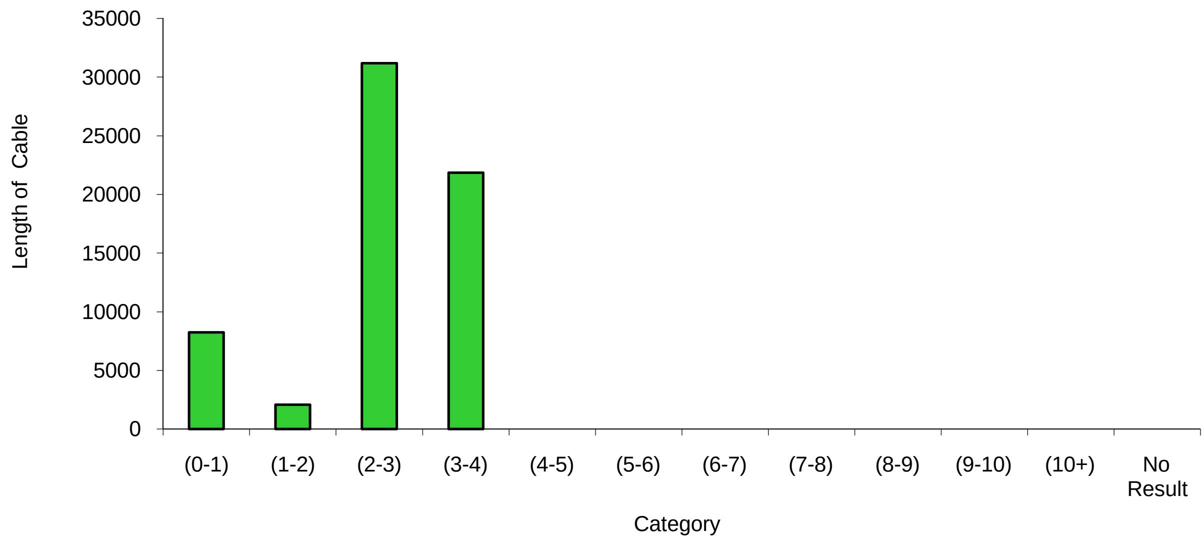


Figure 8 shows that the condition of our remaining 66kV underground cables is very good. This is to be expected due to their age and the fact they are not heavily loaded due to our N-1 security standard.

Figure 9: Year 10 66kV Underground Cable Health Index Profile

Category	Number of Assets
(0-1)	772
(1-2)	7,519
(2-3)	2,004
(3-4)	25,154
(4-5)	11,331
(5-6)	16,537
(6-7)	0
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	0
Total	**63,317**

Figure 10: Year 10 66kV Underground Cable Health Index Profile

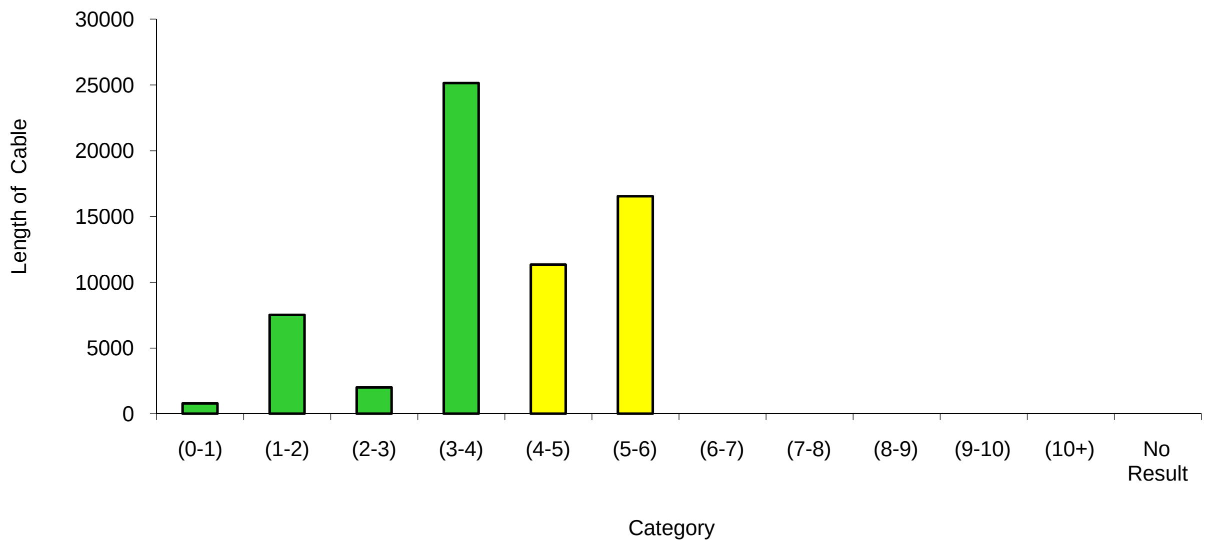


Figure 11: Year 0 66kV Underground Cable Joint Health Index Profile

Category	Number of Assets
(0-1)	128
(1-2)	10
(2-3)	11
(3-4)	16
(4-5)	36
(5-6)	0
(6-7)	0
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	26
Total	**227**

Figure 12: Year 0 66kV Underground Cable Joint Health Index Profile

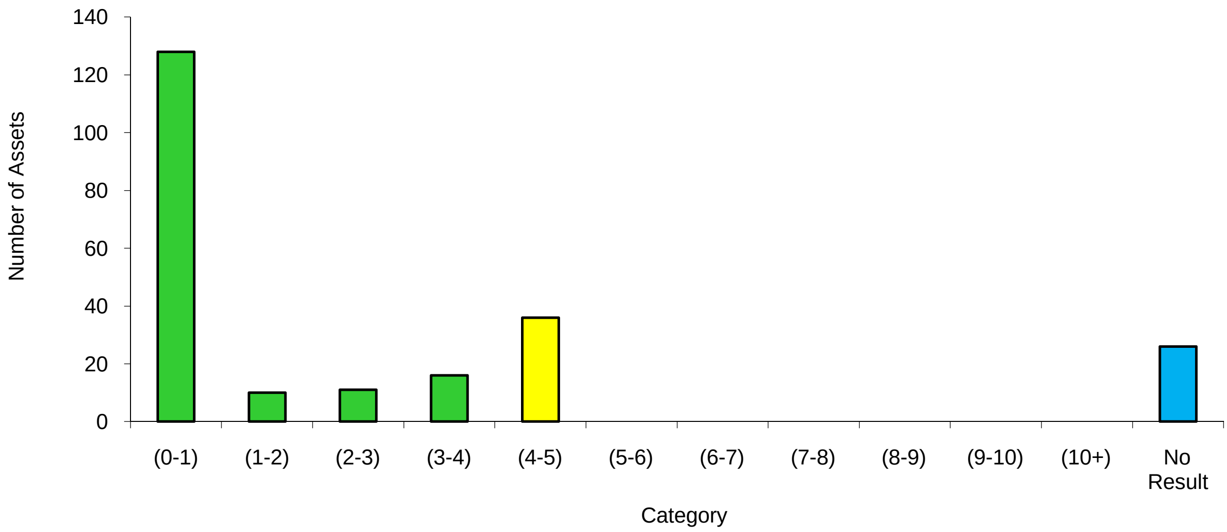
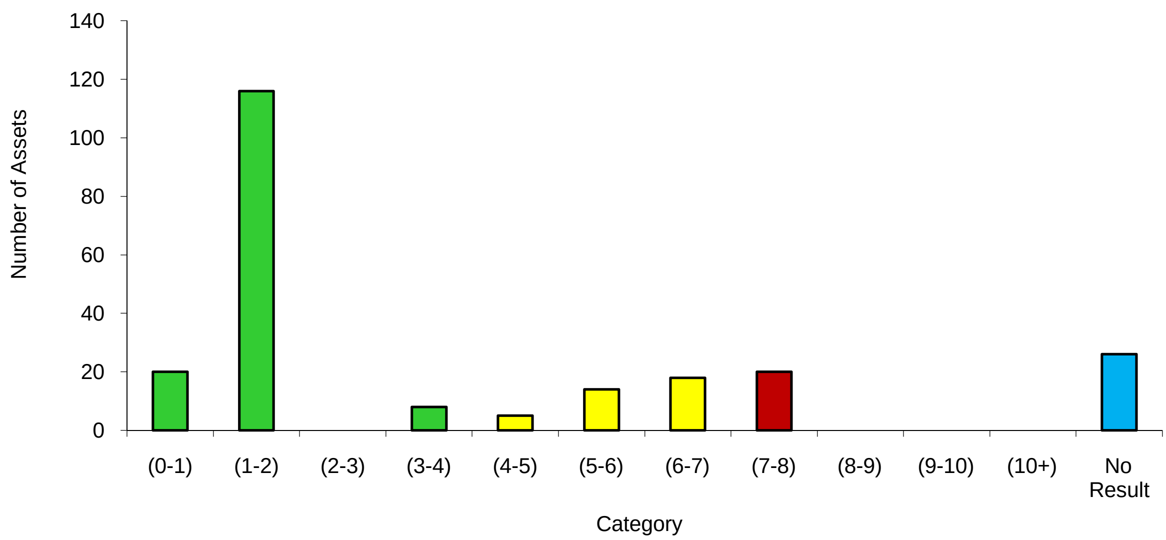


Figure 12 shows the current health index profile of our 66kV cable joints. It also clearly illustrates that there are a number of joints that we have very little condition data for. A programme is being developed to investigate these 'unknown' joints further.

Figure 13: Year 10 66KV Underground Cable Joint Health Index Profile

Category	Number of Assets
(0-1)	20
(1-2)	116
(2-3)	0
(3-4)	8
(4-5)	5
(5-6)	14
(6-7)	18
(7-8)	20
(8-9)	0
(9-10)	0
(10+)	0
No Result	26
Total	**227**

Figure 14: Year 10 66kV Underground Cable Joint Health Index Profile



Figures 10 and 14 show the condition of our 66kV underground cable and joints in 10 years time if no further investment is made in refurbishment.

4.3 Historical Issues

In the past twenty years, a few issues of historical significance have impacted and changed our 66kV asset management practices, these are:

- Prior to the 1998, the Christchurch MED had purchased cables from AEI, Pirelli, Dainichi, Hitachi and BICC. None of these joints have developed major electrical faults, other than minor oil leaks.

- After the 1998/1999 Auckland CBD blackout, an expert-lead investigation came to the conclusion that the primary cause of failure of Auckland's 110kV self-contained oil-filled cables was that the joints buckled because the original cable joint was inadequate to withstand the thermal expansion forces when being run at full or above normal rating. An Orion board driven review prompted a thorough investigation and decided on a programme of replacing and reinforcing the British joints – AEI, Pirelli and BICC. As this progressed, the Hitachi joints were also indicated as a weak joint that were unable to uphold the buckling effects. Only the Dainichi joint design at the time was deemed fit to be placed back into service.

- After a series of Canterbury earthquakes in 2010/2011, significant ground movement in areas, especially in the eastern suburbs, caused damage beyond repair to two Orion 66kV cables - Brighton to Dallington AEI cable (built in 1949) and Brighton to Bromley Dainichi cable (built in 1968). All relevant standards and engineering practices are currently under review in conjunction with inputs from external experts. The aim is to build resiliency into the network in to lessen the impact of any further earthquakes.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

The purpose of Orion's asset management practices is to ensure the 66kV cables are managed in a manner that is consistent with Orion's corporate obligations to deliver effective and efficient services.

To ensure astute asset management practices, Orion employs several software, processes/policy, databases, and engineering practices to monitor throughout the lifecycle of the 66kV cables. This historical data, engineering expertise, benchmarks, feedbacks, and the performance of the 66kV cables is constantly under review by technical experts and asset engineers. For any events whereby outside expertise is required, an external consultant will be employed to provide independent judgment to add value to the improvement process.

This data and results in conjunction with sound engineering judgements constitute the basis for the calibration and modelling of the Condition Based Risk Management Model (CBRM), which in turn produces the health index indicator and risk profile of the 66kV cables. The health index indicator will be utilised as one of the core elements in the decision making process for any maintenance or replacement programmes.

The key tools, software, databases and standards employed are shown in the followings:

- GIS – Accurately maps the location of our underground services.

- Cable Digging Awareness Program – A cable awareness program running in association with external contractors to minimise the risk of cable interruption for any digging in close proximity to the network cables.

- Fault Incident Report – Database serves as the hub and is used to collect all root cause of any fault or interruption and present the information in a usable form.

- Cables Database – Database provides all the relevant cable information e.g. the cable lengths, joints and time of installations.

- Underground Cable Design NW70.52.01 – Cable design standard outlining the engineering design criteria, mainly for the use as a guideline for any Orion's engineering design. The purpose is to ensure the design, incorporates acceptable engineering principles in optimising cable rating, cable route, minimising variation and smoothes the installation process.

- Cabling Installation & Maintenance NW72.22.01 – Procedures outlining the operation guidelines for the contractor when commencing cable installation and maintenance.

- Condition Based Risk Management Model (CBRM) – Excel based models to profile the health index and risk profile of the 66kV cable based on the asset condition, calibration and consequence.
- DigSILENT – Software Orion employed to model load-flow for any network development driven by load or major project requirements.

5.2 EMERGENCY SPARES

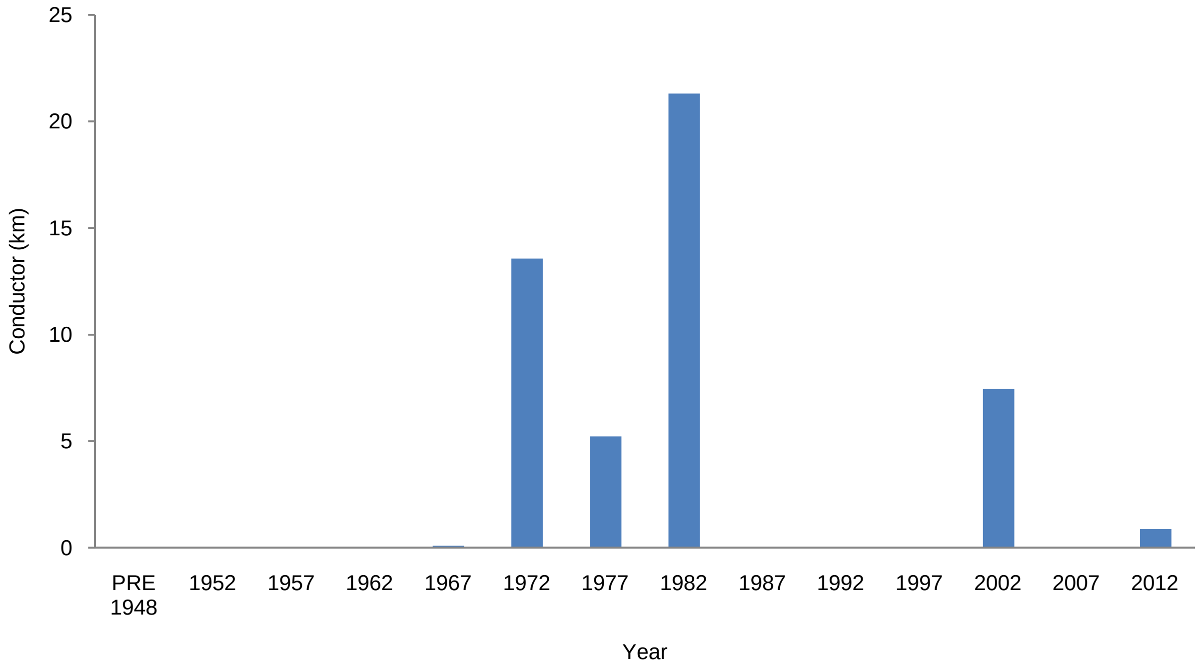
Orion holds emergency spares of 66kV joints and cable lengths to reduce any potential cable outage time in the event of a fault. These spares are stored at Connetics and are readily available when required. The number of spares kept is assessed as the 66kV increases and when faults occur.

5.3 66KV UNDERGROUND CABLE LIFECYCLE

The average age of the 66kV cables is 26 years and is currently operating satisfactory. The assigned end of life age for Orion 66kV cables is 60 years.

A significant amount of asset management practices have been put in place to minimize any premature failure of the asset. Prior to the Canterbury earthquakes, a programme to replace risky oil joints had been undertaken on a yearly basis. Our immediate priority is to address and monitor any 66kV cables that could have deteriorated due to seismic movement and also manage and update Orion current engineering practices and resource availability in response to the rebuilding process.

Figure 15: Age Profile 66kV Underground Cables



5.4 MAINTENANCE PLAN

The condition of our 66kV underground cables is monitored by:

- an annual inspection and sheath test of all cables with any planned repairs completed the next year

- alarms fitted to give early warning of low oil pressure and levels via the SCADA system. Immediate investigation and rectification of the problem follows any oil alarm. To give better monitoring and analysis we install pressure transducers at the ends of cables in conjunction with joint upgrading
- continuous temperature monitoring at a potential ‘hot spot’ on the Addington-Armagh T1 cable – this also reports via the SCADA system
- other cables are currently being identified for further monitoring work.

The following maintenance work is planned:

- ensure contractors with suitable skills are available for oil-filled cable jointing
- review the thermal properties of backfill material around 66kV cables in areas where tests indicate that the cable’s rating is compromised
- continue inspecting joints for signs of thermal-mechanical damage.

As a direct result of the recent earthquakes, we are developing an inspection/refurbishment plan for our cable joints.

5.5 REPLACEMENT PLAN

There is no replacement work foreseen currently for the next 10 years. However, there are a number of major project being proposed to reinforce Orion subtransmission 66kV networks.

5.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.7 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.8 DISPOSAL PLAN

In 2010 an assessment of the Bromley-Portman 66kV cable showed that it was no longer economically feasible to use this cable as an 11kV incomer to Portman zone substation. As a result it was removed from service.

5.9 RISK ANALYSIS

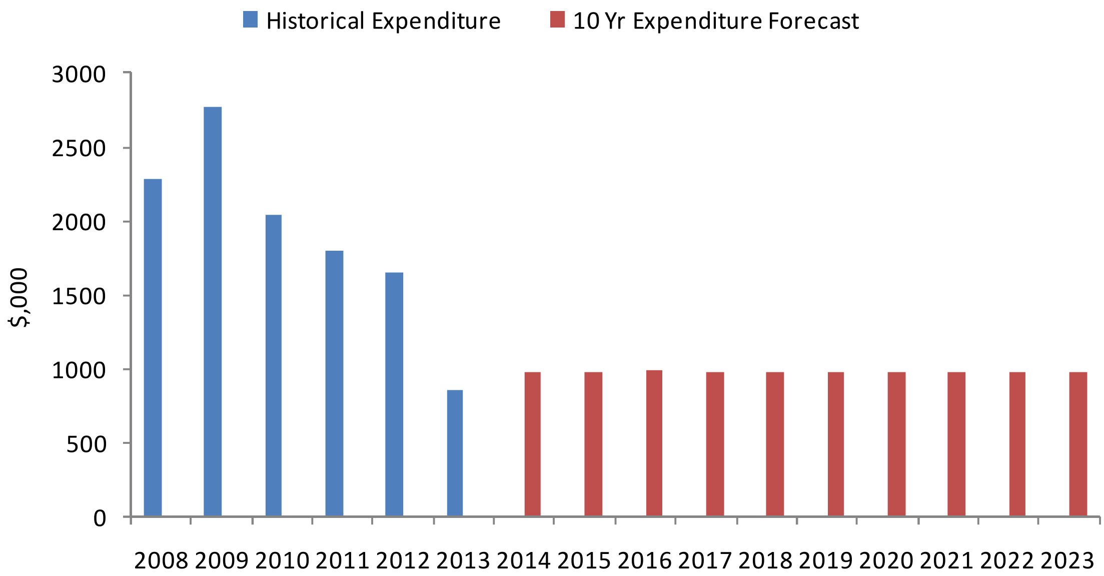
A risk analysis review was undertaken as part of the urban network subtransmission architecture review. Refer to NW70.60.05 for further details.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 16: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 17: Historical 66kV Underground Cables Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	2264	2738	1953	1019	26	780
Non-Scheduled	5	33	80	6	8	30
Emergency	18	5	10	782	1619	50
Total	**2286**	**2775**	**2043**	**1807**	**1653**	**860**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 18: 66kV Underground Cables Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	880	880	880	880	880	880	880	880	880	880
Non-Scheduled	30	30	30	30	30	30	30	30	30	30
Emergency	70	70	85	70	70	70	70	70	70	70
Total	**980**	**980**	**995**	**980**	**980**	**980**	**980**	**980**	**980**	**980**

Our scheduled maintenance for 66kV underground cables is tendered out as part of our contracting model. There has been an increase in budget as we allow for further inspections/ refurbishment of some of our cable joints. This is the dominant factor in our forecasted expenditure.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

33kV Underground Cables

Asset Management Report YE 2012

NW70.00.31

Table of Contents

1 INTRODUCTION

This document covers our 33kV underground cables and details the criteria and asset management practices used to ensure we obtain effective lifecycle performance and acceptable service life.

2 ASSET DESCRIPTION

2.1 GENERAL

Our subtransmission 33kV cable asset consists of approximately 33km of circuit length cable, buried directly in the ground. It is mostly situated in the western part of Christchurch city, with sections of cable in Rolleston, Lincoln, Prebbleton and Springston, and is made up approximately as follows:

- PILCA 2.7km (Installed 1967-1988)
- XLPE 30.5km (Installed 1993-2012)

In recent years there has been an increasing amount of 33kV overhead line replaced by underground cables as land has been developed and road controlling authorities have requested removal with road upgrades. Also, we have replaced all of our oil filled cables with XLPE cables as a cost effective way to address the risk of joint failure in our oil filled cables.

Figure 1: 33kV Underground Cables

Conductor Type	Cct Length (m)	Average Install Year	Average Age (Years)
.3 Cu PILCA	292	1967	45
.3 Al PILCA	234	1984	28
185 Cu PILCA	471	1988	24
300 Al PILCA	1,761	1977	35
150 Cu XLPE	20	2002	10
300 Cu XLPE	27	2010	2
300 Al XLPE	30,447	2006	6
630 Cu XLPE	101	2005	10
Total Length	33,205 metres		

3 ASSET PERFORMANCE

The cable sizes are as shown in the circuit listing (on the following page) and are solid insulation with a nominal rating of 425A or 24MVA.

Our records of cable failure indicate that terminations and cable joints appear to be the predominant failure mode. With our XLPE cables we have seen failures of joints and terminations due to incorrect installation practices. These issues have been addressed by introducing new joint and termination kits and improved training.

The 33kV cables performed relatively well during the earthquakes, sustaining no major damage. However a rigorous maintenance schedule is planned to take place over the next few years to ensure the integrity of all the cables has not been compromised and there is no evidence of any accelerated deterioration.

Figure 2: 33kV Cable Details

Cable circuit	Length (m)	Type	Size	Winter rating (A)
Islington GXP 2102-Harewood 234	690	XLPE	300 Al	475*
Islington GXP 1036-Moffett 334	172	Paper lead	.3 Cu	313
Islington GXP 2092-Moffett 344	136	Paper lead/XLPE	300Al/.3 Cu	313
Islington GXP 936-Sockburn T1	2,019	XLPE	300Al	475*
Islington GXP 2062-Sockburn T2	3,513	XLPE	300Al/630Cu	372
Islington GXP 976-Sockburn T3	3,486	XLPE	300Al	475*
Islington GXP 886-Harewood 224	3,486	PILCA/XLPE	300Al	319
Islington GXP 966-Hornby 572-582	1,848	XLPE	300Al	306*
Islington GXP 2072-Hornby 532-542	1,852	XLPE	300Al	338*
Springston 1206-Shands 436	67	PILCA	300Al	365*
Hornby 502-512-Shands 454	830	PILCA/XLPE	300Al	365*
Hornby 562-572-Prebbleton 4832	4,280	XLPE	300Al	365*
Prebbleton 4842-Lincoln 3434	781	XLPE	300Al	365*
Hororata GXP 1226-Hororata 924	95	PILCA	.3Al	280*
Hororata GXP 1206-Annat 1106-Kimberley	65	PILCA	.3Al	280*
Springston GXP 1206-Rolleston 3234	2,945	XLPE	300Al	475*
Springston GXP 1146-Springston 3554	74	PILCA	.3Al	280*
Springston GXP 1186-Springston 3544	80	PILCA	185Cu	355*
Springston GXP 1176-Motukarara-Lincoln	4,263	XLPE	300Al	
Springston GXP 1196-Weedons 3324	371	PILCA/XLPE	300Al/185Cu	355*
Springston GXP 1226-Lincoln 3432	177	XLPE	300Al	
Springston 3532-Motukarara 3632/3642	154	PILCA/XLPE	300Al/185Cu	355*
Motukarara 3642/3652-Little River 3812	79	XLPE	300Al	
Motukarara 3602/3612-Teddington 3704	105	XLPE	300Al	
Springston GXP 1166-Brookside 3114	172	XLPE	300Al	475*
Islington GXP 1026-Hornby 512-522	1,836	XLPE	300Al	
Islington GXP 2082-Shands 444	20	XLPE	150Cu	
Hornby zone substation	151	XLPE	300Al/630Cu	
Motukarara zone substation	70	XLPE	300Al	
Duvauchelle zone substation	50	XLPE	300Al	
Lincoln zone substation	62	XLPE	300Al	
Shands zone substation	12	XLPE	300Al	
Prebbleton zone substation	19	XLPE	300Al	
Bankside zone substation	27	XLPE	300Cu	

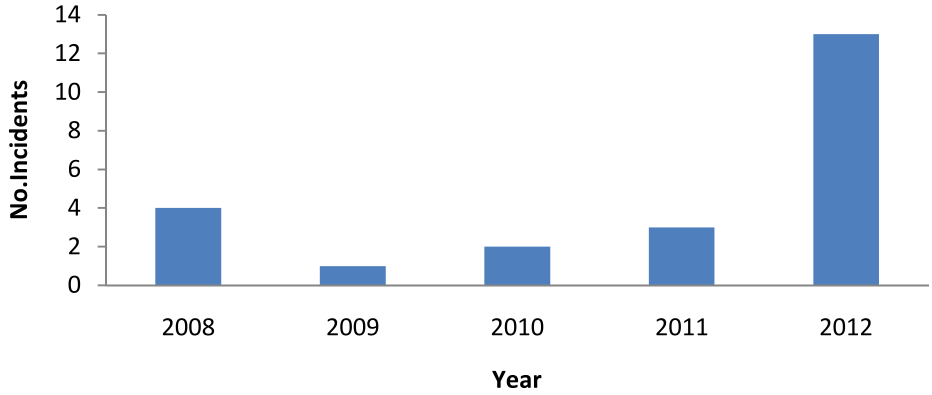
Note: some of these circuits may have an overhead line component that will affect overall circuit rating.

* Nominal rating – investigation to determine full rating to be completed.

Figure 3: Number of 33kV Underground Cable Incidents Per Year

Mode	2008	2009	2010	2011	2012	Total
Cable	1			3		4
Terminations	2				1	3
Oil Pressure	1	1	2		12	16
Total	**4**	**1**	**2**	**3**	**13**	**23**

Figure 4: Number of 33kV Underground Cable Incidents Per Year



4 ASSET CONDITION

4.1 GENERAL

These cables are in good condition and, to date, no sheath faults have occurred.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our 33kV underground cables. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual underground cable and joint. This effectively gives the assets a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Figure 5: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 6: Year 0 33kV Underground Cable Health Index Profile

Category	Number of Assets
(0-1)	19,197
(1-2)	8,799
(2-3)	1,846
(3-4)	2,597
(4-5)	0
(5-6)	0
(6-7)	0
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	0
Total	**32,438**

Figure 7: Year 0 33kV Underground Cable Health Index Profile

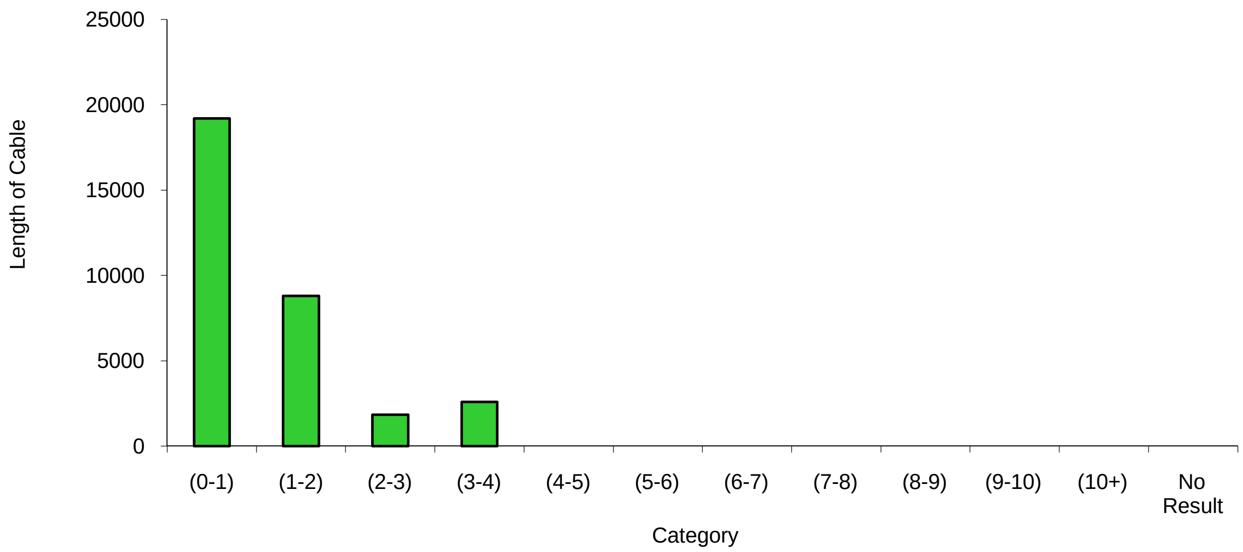


Figure 7 shows that the condition of our 33kV cables is good. This is expected due to their age and the fact they are not heavily loaded due to our N-1 security standard.

Figure 8: Year 10 33kV Underground Cable Health Index Profile

Category	Number of Assets
(0-1)	9,090
(1-2)	16,742
(2-3)	2,164
(3-4)	1,846
(4-5)	2,597
(5-6)	0
(6-7)	0
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	0
Total	**32,439**

Figure 9: Year 10 33kV Underground Cable Health Index Profile

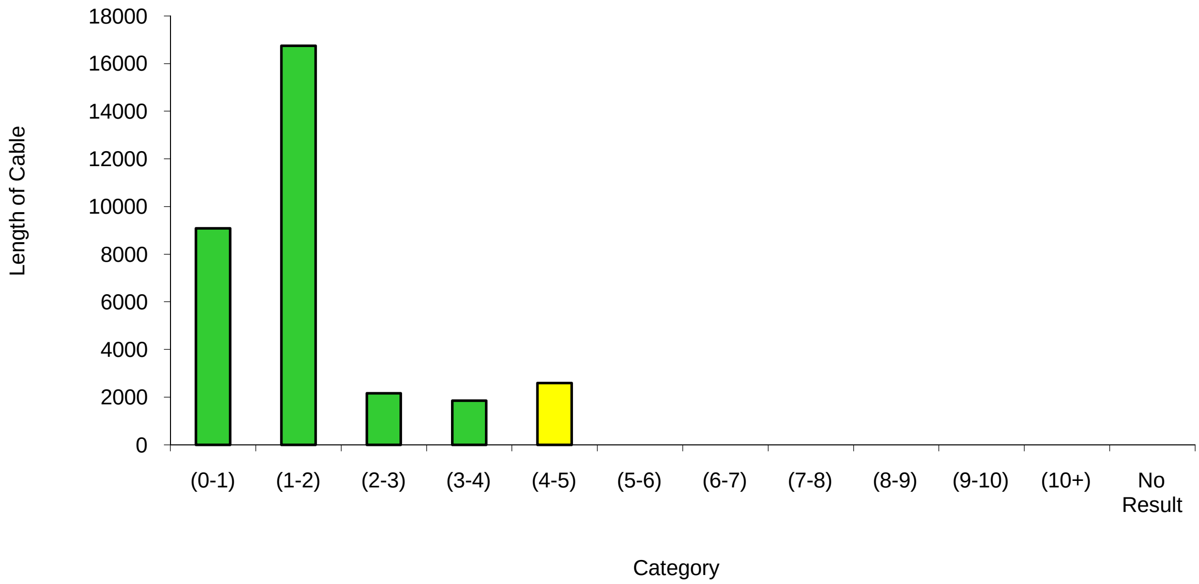


Figure 10: Year 0 33kV Underground Cable Joint Health Index Profile

Category	Number of Assets
(0-1)	118
(1-2)	28
(2-3)	7
(3-4)	6
(4-5)	7
(5-6)	0
(6-7)	0
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	38
Total	**204**

Figure 11: Year 0 33kV Underground Cable Joint Health Index Profile

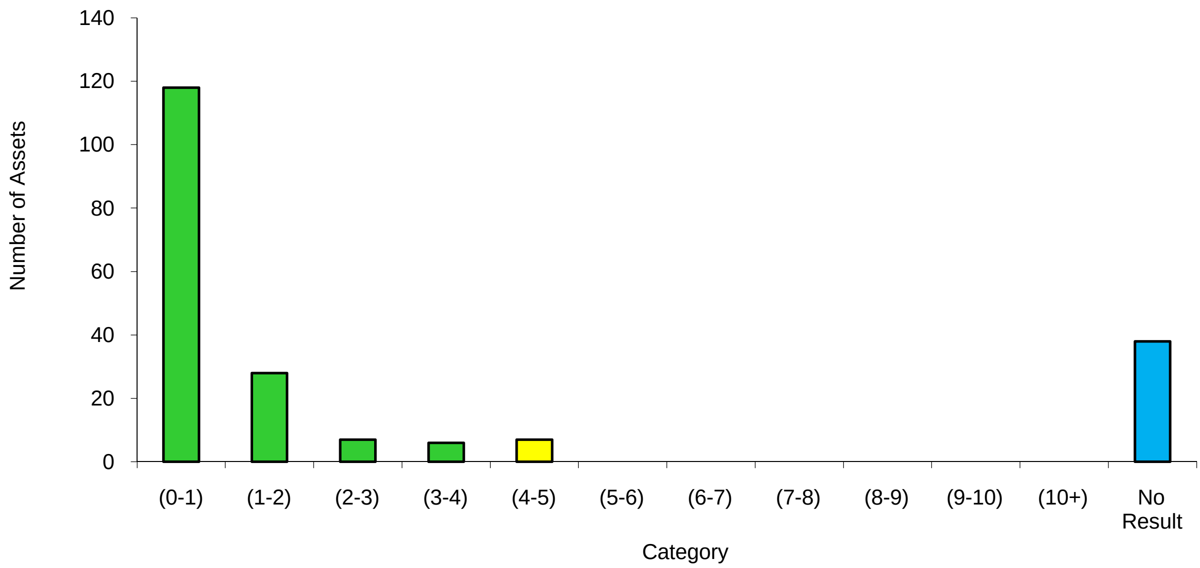
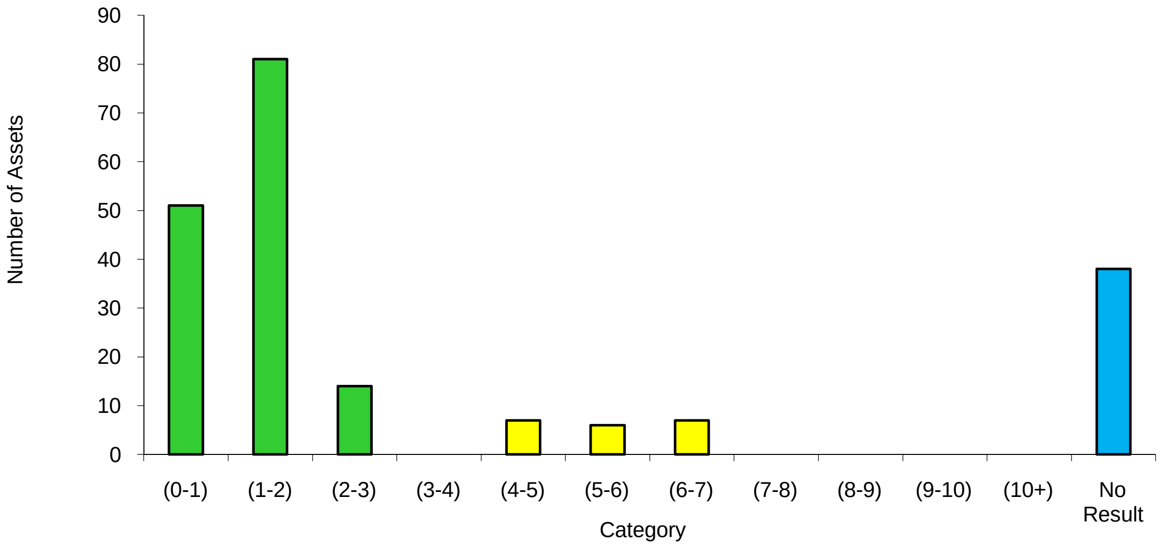


Figure 12: Year 10 33kV Underground Cable Joint Health Index Profile

Category	Number of Assets
(0-1)	51
(1-2)	81
(2-3)	14
(3-4)	0
(4-5)	7
(5-6)	6
(6-7)	7
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	38
Total	**204**

Figure 13: Year 10 33kV Underground Cable Joint Health Index Profile



4.3 HISTORICAL ISSUES

Historically, there have not been any significant issues with the 33kV cables. All Oil filled cables have been replaced before any issues arose. The 33kV cables and joints performed well throughout the earthquakes.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

We employ a number of different asset management practices for different asset groups.

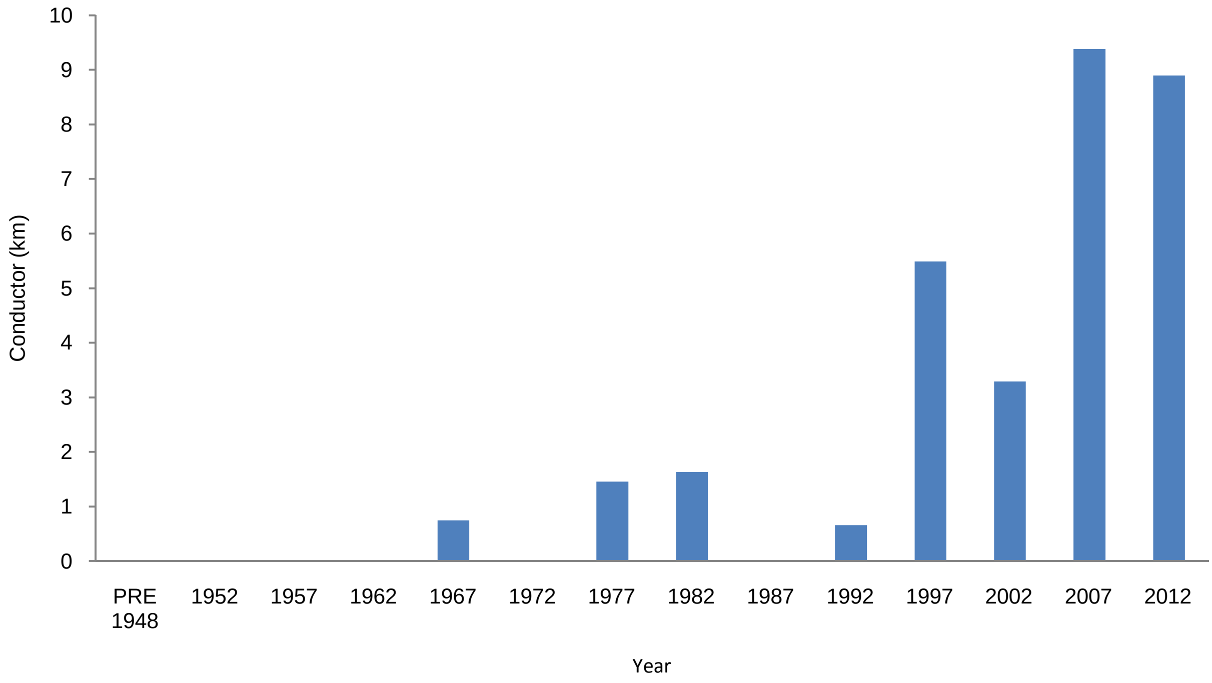
- GIS – Accurately maps the location of our underground services.
- Cable Digging Awareness Program – A cable awareness program running in association with external contractors to minimise the risk of cable interruption for any digging in close proximity to the network cables.
- Fault Incident Report – Database serves as the hub, is used to collect all root cause of any fault or interruption and interpret the information in a presentable form.
- Cables Database – Database provides all the relevant cable information for example the cable lengths, joints and time of installations.
- Underground Cable Design NW70.52.01 – Cable designs standards outlining the engineering design criteria, mainly for the use as a guideline for any Orion's engineering design. This purpose is to ensure outcomes of the design, incorporates acceptable engineering principles in optimising cable rating, cable route, minimising variation and smoothen installation process.
- Cabling Installation & Maintenance NW72.22.01 – Procedures outlining the operation guidelines for the contractor when commencing cable installation and maintenance.
- Condition Based Risk Management Model (CBRM) – Excel based models being run to profile the health index and risk profile of the 33kV cable based on the asset condition, calibration and consequence.
- DigSILENT – Software Orion employed to model load flow for any network development driven by load or major project requirement.

5.2 33KV UNDERGROUND CABLE LIFECYCLE

The average age of our 33kV cables is 20 years. In the past decade, most of the emergency repairs revolved around fixing leaky oil-filled cable joints or rectifying oil pressure issues. All of these oil based issues are now behind us with the removal of the oil-filled cables and the adoption of XLPE cable.

The 33kV cables and joints performed well throughout the earthquakes with no major failure or replacement needed. Nevertheless, the immediate strategy is to increase the monitoring and testing schedule to prevent any premature failure or to detect any deterioration due to seismic movement that we are unaware of. Other initiated programmes also include the updating of Orion's current engineering practices by engaging with external experts or academics and managing resource availability.

Figure 14: Age Profile 33kV Underground Cables



5.3 MAINTENANCE PLAN

The condition of this asset is monitored by an inspection and sheath test, where practicable, every year.

5.4 REPLACEMENT PLAN

We have replaced all of our 33kV oil-filled cables due to issues with the joints (similar issue to that in the 66kV system). It was more cost effective to replace the entire cable with XLPE than it was to refurbish/upgrade all of the joints.

Any further 33kV cable installations will be carried out as a major project or as part of overhead to underground conversion works driven by local authorities. There are no plans to replace any of the existing 33kV cables in the next ten years.

5.5 DISPOSAL PLAN

We have no plans to dispose of any 33kV cables.

5.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.7 DELIVERABILITY

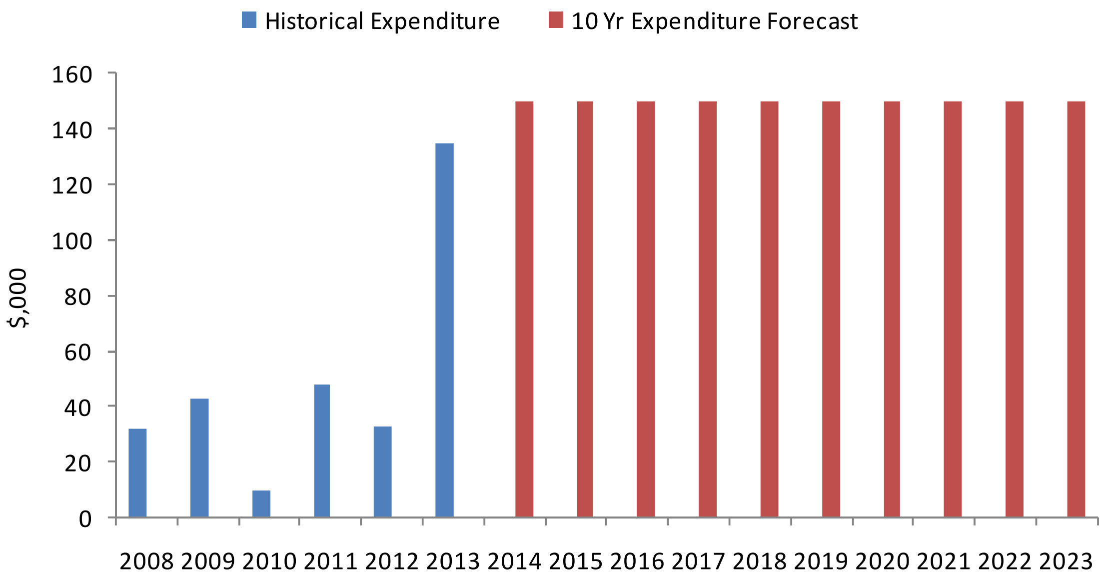
By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors with their resource planning.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 15: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 16: Historical 33kV Underground Cable Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	0	7	0	1	1	45
Non-Scheduled	3	35	7	1	2	50
Emergency	28	1	2	46	30	40
Total	**32**	**43**	**10**	**48**	**33**	**135**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 17: 33kV Underground Cable Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	45	45	45	45	45	45	45	45	45	45
Non-Scheduled	50	50	50	50	50	50	50	50	50	50
Emergency	55	55	65	55	55	55	55	55	55	55
Total	**150**	**150**	**160**	**150**	**150**	**150**	**150**	**150**	**150**	**150**

Our scheduled maintenance for 33kV underground cables is tendered out as part of our contracting model.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 18: Historical and Forecast Expenditure

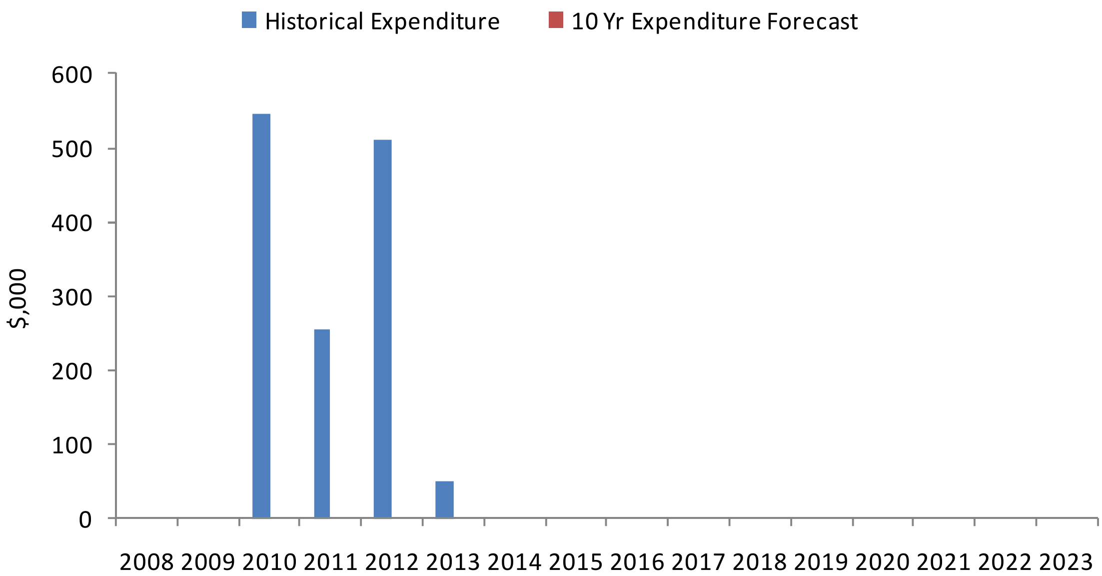


Figure 19: Historical 33kV Underground Cables Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	0	0	547	201	511	50
Total	**0**	**0**	**547**	**201**	**511**	**50**

We currently have no plans to replace any 33kV cables in the next ten years.

11kV Underground Cables

Asset Management Report YE 2012

NW70.00.30

Table of Contents

1 INTRODUCTION

This document covers each of our 11kV underground cable categories and details the criteria and asset management practices used to ensure we obtain effective lifecycle performance and acceptable service life.

The 11kV underground distribution generally supplies transformers that supply the LV distribution network.

2 ASSET DESCRIPTION

2.1 GENERAL

Our 11kV cable network is approximately 2,400km of circuit length of underground cable and is largely concentrated in the urban area of Christchurch (approx 90% of total length).

These cables are classed as subtransmission (feeder and primary) and distribution (secondary) cables as follows:

- Feeder cables which supply the 11kV zone substations from Transpower GXPs
- Primary cables which supply the network substations from the zone substations
- Secondary cables which supply the distribution substations from the network substations.

The 11kV cables are predominantly of the paper lead variety with an expected life of 70 years.

Figure 1: 11kV XLPE Underground Cables

Conductor Type	Cct Length (m)	Average Install Year	Average Age (Yrs)
.25 XLPE	5	2011	1
16 Cu XLPE	286	1995	17
16 Al XLPE	315	1984	28
25 Cu XLPE	777	1995	17
25 Al XLPE	46749	2001	11
35 Cu XLPE	911	1999	13
35 Al XLPE	169077	2007	5
70 Cu XLPE	724	1993	19
70 Al XLPE	27344	1994	18
95 Cu XLPE	191	2008	5
95 Al XLPE	202280	2007	5
150 Cu XLPE	307	1987	25
150 Al XLPE	3159	1996	16
185 Cu XLPE	1345	2010	2
185 Al XLPE	18427	2006	6
240 Al XLPE	12107	2000	12
300 Cu XLPE	418	2006	6
300 Al XLPE	147281	2008	4
400 Cu XLPE	8586	2009	3
400 Al XLPE	4263	2002	10
630 Cu XLPE	944	2005	7
Other XLPE	10	2011	1
Total Length	645,504 metres		

Figure 2: 11kV PILCA Underground Cables

Conductor Type	Cct Length (m)	Average Install Year	Average Age (Yrs)
0.0225 Cu PILCA	2094	1961	51
0.04 Cu PILCA	331493	1967	45
.05 Cu PILCA	2944	1924	88
.06 Cu PILCA	45671	1947	65
.1 Cu PILCA	3278	1969	43
.15 Cu PILCA	32454	1966	46
.15 Al PILCA	94957	1973	39
.1 Al PILCA	7365	1965	47
.2 Cu PILCA	65026	1951	61
.25 Cu PILCA	229807	1965	47
.3 Cu PILCA	4329	1959	53
.3 Al PILCA	8286	1969	43
.4 Al PILCA	1458	1971	41
.5 Cu PILCA	47397	1969	43
.5 Al PILCA	62593	1972	40
.6 Cu PILCA	735	1968	44
25 Cu PILCA	69102	1983	29
25 Al PILCA	766	1982	30
35 Cu PILCA	2614	1974	38
35 Al PILCA	1268	2001	11
70 Cu PILCA	2575	1980	32
70 Al PILCA	15501	1983	29
95 Cu PILCA	2820	1987	25
95 Al PILCA	329622	1987	25
150 Cu PILCA	4185	1987	25
150 Al PILCA	53505	1991	21
180 Al PILCA	143	1977	35
185 Cu PILCA	12537	1996	16
185 Al PILCA	30490	1997	15
240 Cu PILCA	283	1978	34
240 Al PILCA	1193	1990	22
300 Cu PILCA	1065	1982	30
300 Al PILCA	154263	1989	23
400 Cu PILCA	3363	1987	25
400 Al PILCA	785	1991	21
Other PILCA	2752	1964	48
Total Length	1,628,718 metres		

3 ASSET PERFORMANCE

The September 2010 and February 2011 earthquakes caused a number of 11kV cable faults. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale. The cables in the affected area total approximately 90km.

The majority of cables that failed were PILCA type having been installed for an average of 40-50 years. Some of these cables had multiple faults. The failure modes were either joints (typically older pitch filled) being pulled apart or significant movement of the cables causing the deformation and failure of the cables outer membrane/lead and subsequently the paper insulation.

The M6.3 earthquake in June 2011 caused some further damage to our cables. However, it was limited to areas that were already damaged in February; therefore the impact on our recovery programme was minimal.

3.1 11KV FEEDER SYSTEM

These cables supply the 11kV zone substations from Transpower GXPs and are currently the subject of a study to determine the rating of each cable based on the thermal resistivity of the cable bedding material. The study results so far indicate that under normal conditions the capabilities of the cables are within the present loading requirements of the substations, but during single circuit outages the capacity of the remaining circuits falls short of the total substation load.

3.2 PRIMARY 11KV SYSTEM

This system is designed to be run in single or multiple closed rings. Each ring usually starts at a zone substation bus and includes one or more network substations before returning via a different route to the starting zone substation. To provide additional 11kV tie capacity, primary circuits may also be provided in some cases to alternative zone substations. A primary ring consists of dedicated runs of cable between a zone substation bus and a network substation or between network substations. Each end of a primary cable is protected with a circuit breaker using differential protection. No distribution substation load is supplied directly from the primary cable system. The primary system is designed to be loaded up to the point where, in the event of a single cable fault contingency, no primary cables will become overloaded and no loss of supply will result. The standard conductor is 300mm^2 Al/0.25in^2 Cu PILC giving each circuit a rating of 365A or 7MVA.

3.3 SECONDARY 11KV SYSTEM

This system consists of radial feeders, most of which are supplied from network substations. However, some secondary feeders are also supplied from a zone substation bus. Depending on the area and load supplied, secondary feeders have nominal ratings ranging between 1 and 6MVA. Secondary feeders are loaded to the extent that, in the event of a single fault contingency, it should be possible to split the faulty feeder so that the healthy portions can be supplied from adjacent feeders without overloading those feeders. Generally this would mean that, under normal circumstances, any individual feeder should not be loaded above 70% of cable rating.

The age of the cables making up this asset covers a wide range. The modes of faults on cables are monitored to ensure the high reliability. To date the majority of failure modes include:

- third party damage
- damage of cable during installation or other disturbance causing premature failure
- failure of terminations.

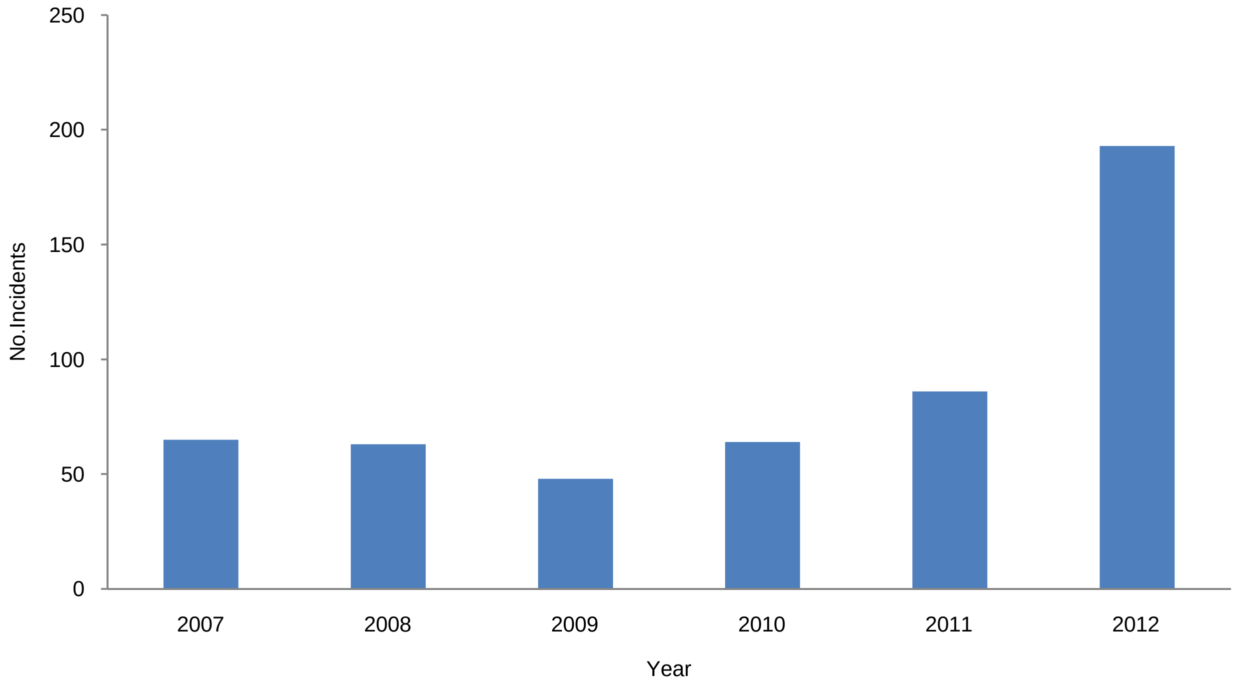
To manage these issues the following actions are taken:

- proactive promotion to contractors of cable locating services
- inspection of contractors during the laying of cables
- ultrasonic and partial discharge monitoring of terminations in zone and network substations
- new cable is now installed with an orange coloured sheath to allow easier identification.

Figure 3: Number of 11kV Underground Cable Fault Incidents Per Year

	2007	2008	2009	2010	2011	2012	Total
Number of Faults	65	63	48	64	86	193	519

Figure 4: Number of 11kV Underground Cable Fault Incidents Per Year



4 ASSET CONDITION

4.1 GENERAL

The condition of these cables is largely assessed by monitoring any failures. Condition testing of a sample of varying cable types and ages has been undertaken using the partial discharge mapping technique. A limited amount of partial discharge was noticeable in a few joints. However, there were no major areas of concern. This indicates that cables are in good condition.

We anticipate that cables that have been subjected to stresses caused by the earthquakes will have higher failure rates in the next few years as compromised cable sheaths and insulation develop faults. To mitigate this we will test the cables in identified areas over the next few years to determine whether maintenance or replacement is required.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our 11kV underground cable population. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

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CBRM Condition Table

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Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 6: Year 0 11kV Underground Cable Health Index Profile

Category	Number of Assets
(0-1)	743,588
(1-2)	727,932
(2-3)	591,418
(3-4)	236,530
(4-5)	101,828
(5-6)	57,042
(6-7)	28,639
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	0
Total	**2,486,977**
Total Number of Failures	**11**

Figure 7: Year 0 11kV Underground Cable Health Index Profile

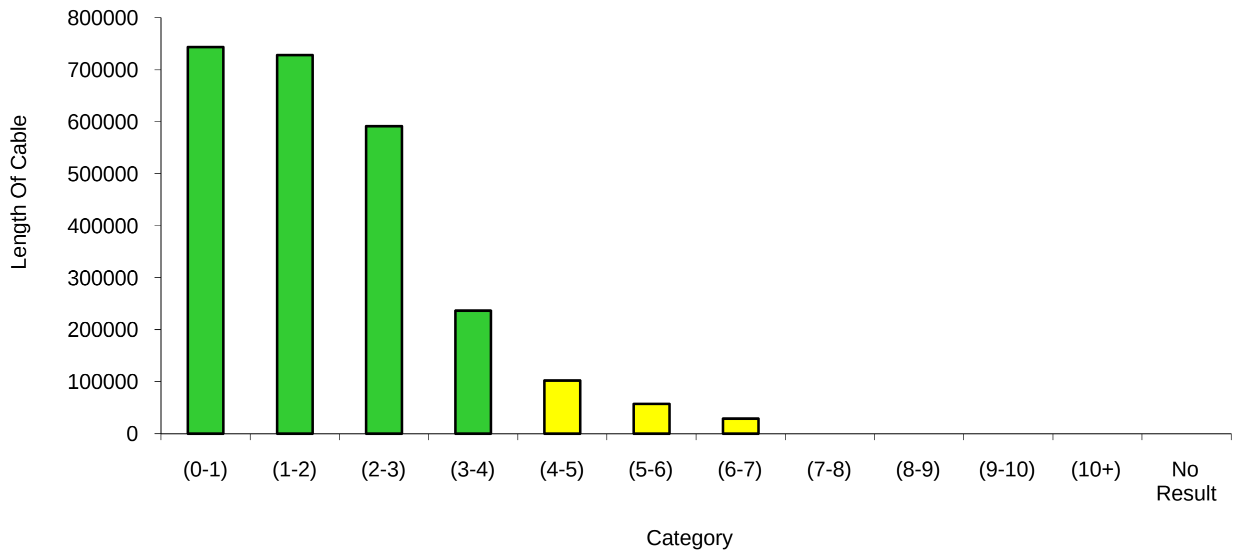


Figure 8: Year 10 11kV Underground Cable Health Index Profile

Category	Number of Assets
(0-1)	219,925
(1-2)	818,222
(2-3)	488,630
(3-4)	386,412
(4-5)	322,371
(5-6)	144,445
(6-7)	68,802
(7-8)	30,932
(8-9)	7,237
(9-10)	0
(10+)	0
No Result	0
Total	**2,486,976**
Total Number of Failures	**12.87**

Figure 9: Year 10 11kV Underground Cable Health Index Profile

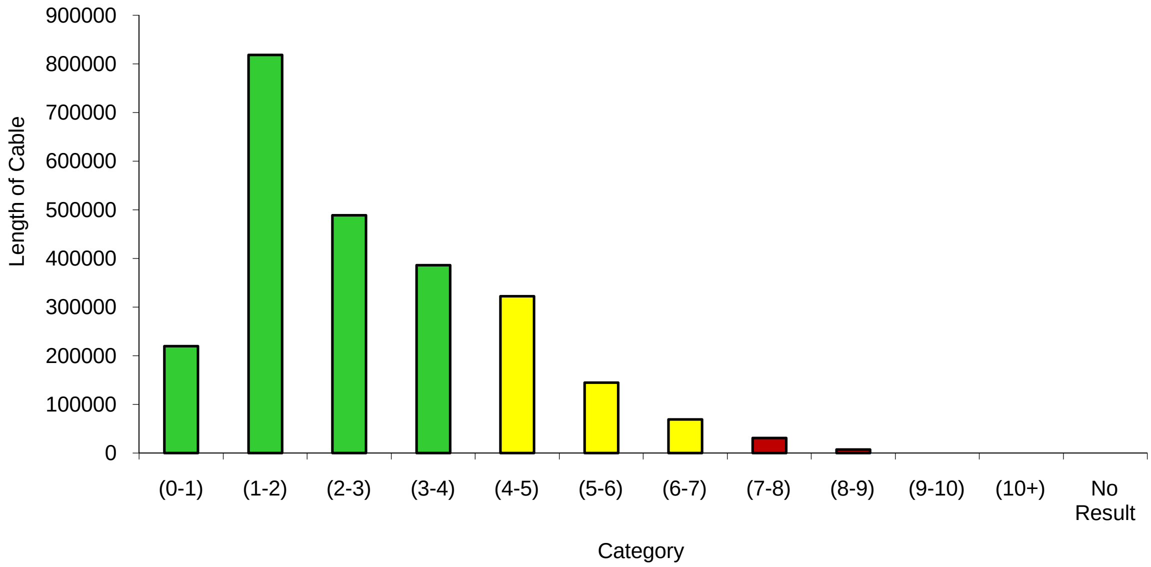


Figure 10: Year 0 11kV Underground Joint Health Index Profile

Category	Number of Assets
(0-1)	6,952
(1-2)	5,255
(2-3)	3,269
(3-4)	2,400
(4-5)	1,309
(5-6)	771
(6-7)	1,134
(7-8)	175
(8-9)	0
(9-10)	0
(10+)	0
No Result	6,459
Total	**27,724**
Total Number of Failures	**4.60**

Figure 11: Year 0 11kV Underground Joint Health Index Profile

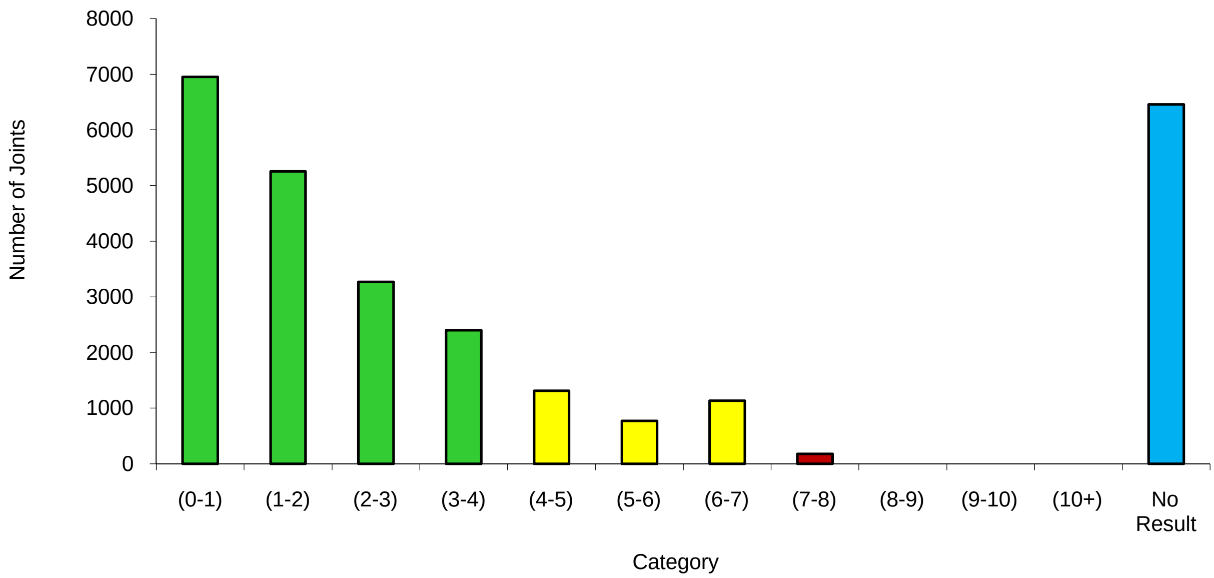
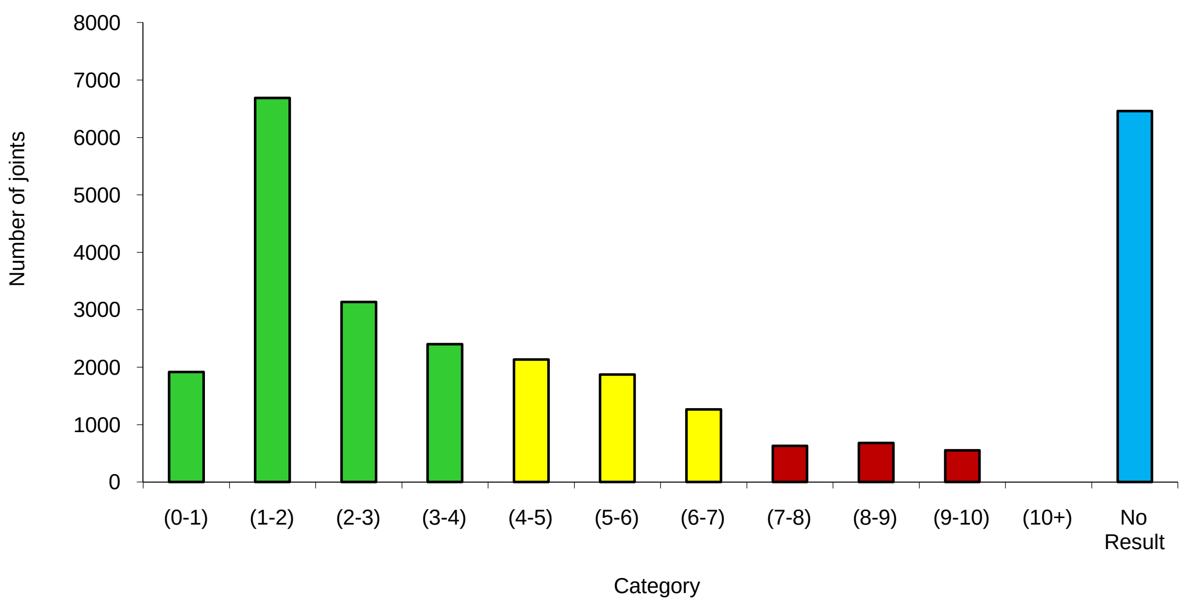


Figure 12: Year 10 11kV Underground Joint Health Index Profile

Category	Number of Assets
(0-1)	1,914
(1-2)	6,687
(2-3)	3,134
(3-4)	2,401
(4-5)	2,135
(5-6)	1,872
(6-7)	1,264
(7-8)	630
(8-9)	678
(9-10)	550
(10+)	0
No Result	6,459
Total	**27,724**
Total Number of Failures	**6.73**

Figure 13: Year 10 11kV Underground Joint Health Index Profile



Figures 7 and 11 show the current condition of our 11kV underground cables and joints. Figures 9 and 13 show the condition of our 11kV underground cables and joints in 10 years time if no further investment is made in refurbishment.

4.3 HISTORICAL ISSUES

Early 11kV terminations onto MSUs were an issue where the cores crossed each other out of the crotch of the cable. This has caused corona discharge, which over time damages the integrity of the insulation and causes it to fail. As a result of this, Orion has moved away from this technique of terminating and decided to trifurcate the cables in the ground so only the 3 single core cables rise above the ground and terminate onto the MSU and Ring Main Units.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

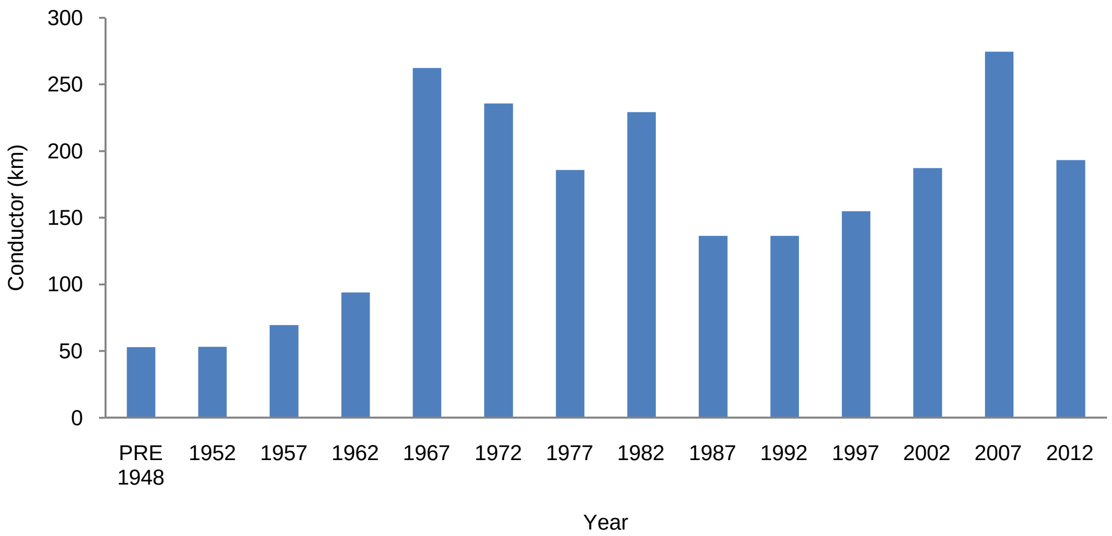
We employ a number of different asset management practices for different asset groups.

- GIS – Accurately maps the location of our underground services.
- Underground Standard Construction Drawings NW72.21.20. These standards outline the methods of underground construction and maintenance practices.
- Equipment Specification NW74.23.04 Distribution Cable 11kV. This sets out the requirements for 11kV cables intended for use on Orion's underground electricity network.
- Installation and Maintenance Specification NW72.22.01. This sets out the requirements for materials and work practices on Orion's underground electricity network.
- Cables Database – This database provides all the relevant cable information for example the cable lengths, joints and time of installations.

5.2 11KV UNDERGROUND CABLE LIFECYCLE

The average age of the 11kV underground network is approximately 30 years old. The overall condition of these cables is good, however we are expecting an increase in the failure rates for cables in the eastern suburbs. We have developed a programme to test the cables in this area to determine if the expected life of these assets has been affected.

Figure 14: Age Profile 11kV Underground Cables



5.3 MAINTENANCE PLAN

We have programmes in place to address identified failure modes of cables. These failure modes have been predominately related to the terminations where an inspection and replacement programme has been implemented.

We will undertake a testing programme on the 11kV cables identified within the areas that were subjected to significant earthquake damage over the next five years.

5.4 REPLACEMENT PLAN

Prior to the earthquakes, we did not have a replacement programme in place for any of our 11kV underground network. As a direct result of the seismic events we have allowed to replace approximately 4km of 11kV cable per year for the next ten years. At the time of writing, we have not yet developed a detailed replacement programme as we are still analysing our failure models and the areas where they are occurring.

5.5 DISPOSAL PLAN

We have no plans to dispose of any of this asset, other than minor disposal associated with changes and rearrangements in the network. No decision has been made yet as to the fate of assets in the red zones.

5.6 CREATION / ACQUISITION PLAN

Additional 11kV cables are installed as a result of the following:

- reinforcement plans
- conversion from overhead to underground as directed by the Christchurch city and district councils
- developments as a result of new connections and subdivisions.

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

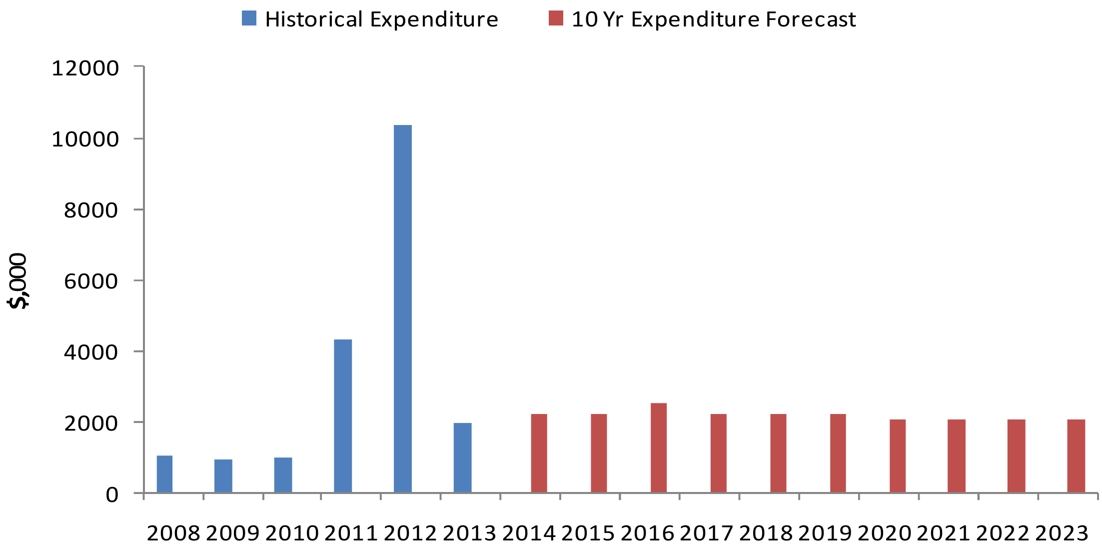
By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 15: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 16: Historical 11kV Underground Cables Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	137	205	220	151	185	710
Non-Scheduled	221	288	61	112	97	80
Emergency	692	481	711	4059	10088	1200
Total	**1050**	**974**	**993**	**4322**	**10370**	**1990**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 17: 11kV Underground Cables Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	510	510	510	510	510	510	360	360	360	360
Non-Scheduled	80	80	80	80	80	80	80	80	80	80
Emergency	1625	1625	1950	1625	1625	1625	1625	1625	1625	1625
Total	**2215**	**2215**	**2540**	**2215**	**2215**	**2215**	**2065**	**2065**	**2065**	**2065**

Our scheduled maintenance for 11kV underground cables is tendered out as part of our contracting model.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 18: Historical and Forecast Expenditure

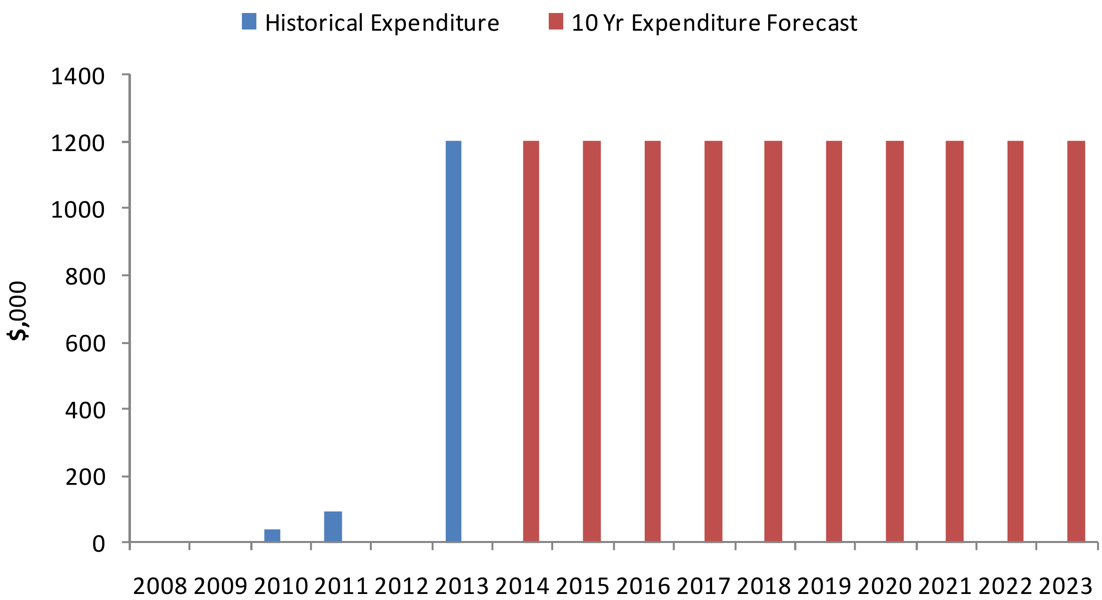


Figure 19: Historical 11kV Underground Cables Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	0	0	38	92	0	1200
Total	**0**	**0**	**38**	**92**	**0**	**1200**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 20: 11kV Underground Cables Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Total	**1200**	**1200**	**1200**	**1200**	**1200**	**1200**	**1200**	**1200**	**1200**	**1200**

As mentioned in Section 5.4, we have allowed for the replacement of approximately 4km of 11kV underground cable per year for the next ten years. As we analyse our faults data, we will refine our replacement programme as appropriate.

Low Voltage Underground Cables and Hardware

Asset Management Report YE 2012

NW70.00.29

Table of Contents

1 INTRODUCTION

This document covers our low voltage (LV) cable distribution network and associated equipment and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from LV cables, distribution cabinets and boxes.

LV underground distribution is located mainly in urban areas. It supplies residential housing and businesses through distribution cabinets and distribution boxes. A condition assessment survey is carried out every five years to identify the maintenance requirements and necessary equipment replacements.

2 ASSET DESCRIPTION

2.1 GENERAL

Our LV cable network is approximately 2,600km of circuit length and is largely concentrated in the urban area of Christchurch. The earlier cables are paper lead. PVC insulation was introduced in 1966 to replace some paper lead cables. In 1974, XLPE insulation was introduced mainly because it has better thermal properties than PVC. Some 430km of the LV cable length is the service cables that are directly T-jointed into the distribution cables (these service cables are not included in Figures 1-3).

Street-lighting cables are also included in this asset group. The street-lighting cable network consists of 1,850km circuit length of underground cable and is largely concentrated in the urban area of Christchurch. Nearly 90% of this cable is included as a fifth core in the main distribution cables.

We have 5,600 distribution cabinets installed on our LV cable network. Sufficient cabinets are needed to allow the system to be reconfigured (that is, each radial feeder must be capable of supplying or being supplied from the feeder adjacent to it) in the event of component failure or other requirements. All of our distribution cabinets are installed above ground. Older ones are generally steel and the later ones are a PVC cover on a steel frame.

We have 32,000 distribution boxes in our LV cable network. These are generally installed on alternate boundaries on both sides of a street. Several types of distribution boxes are in service and are installed above ground. We have deemed in-ground systems unsuitable for our needs. The majority are a PVC cover on a steel base frame, although some older types are concrete and steel.

2.2 ASSET TYPE

We have a variety of different cable types in our LV underground network as shown in Figures 1-3. To distribute electricity to our consumers, the LV cables are connected to distribution cabinets and boxes. Figures 4 and 5 contain details of the different types. Orion's Standard Construction Drawings UE3.7.1 and UE3.7.2 contain photos of the equipment.

Figure 1: XLPE 400V Underground Cables

Conductor Type	Cct Length (m)	Average Install Year	Average Age (Yrs)
.15 Al XLPE	387	1971	41
.3 Cu XLPE	1,122	1970	42
.3 Al XLPE	4,727	1973	39
16mm Cu XLPE	2,480	1991	21
25mm Al XLPE	105	2002	10
25mm Cu XLPE	61,493	1996	16
35mm Cu XLPE	105,092	1997	15
35mm Al XLPE	41	2005	7
50mm Cu XLPE	346	2005	7
70mm Al XLPE	2,196	1995	17
70mm Al XLPE	590	1978	34
70mm Cu XLPE	213,122	1987	25
95mm Al XLPE	62,467	1991	21
95mm Cu XLPE	1,328	1995	17
120mm Cu XLPE	1,151	1989	23
120mm Al XLPE	258,533	2001	11
120mm Cu XLPE	114,333	1992	20
150mm Al XLPE	234	1992	20
150mm Cu XLPE	675	1974	38
185mm Al XLPE	378,045	2002	10
185mm Cu XLPE	65,441	1989	23
240mm Al XLPE	20,568	1994	18
240mm Cu XLPE	82	2004	8
300mm Al XLPE	136,362	2002	10
300mm Cu XLPE	3,653	1999	13
400mm Al XLPE	866	1981	31
400mm Cu XLPE	629	1983	29
500mm Al XLPE	193	1998	14
500mm Cu XLPE	247	1990	22
630mm Cu XLPE	17	2004	8
Other XLPE	1,681	1999	13
Total Length	1,438,207 metres		

Figure 2: PILCA 400V Underground Cables

Conductor Type	Cct Length (m)	Average Install Year	Average Age (Yrs)
.0145 Cu PILCA	165	1932	80
.0225 Cu PILCA	137	1961	51
.04 Cu PILCA	2,363	1967	45
.06 Cu PILCA	958	1968	44
.1 Al PILCA	7,618	1976	36
.1 Cu PILCA	15,748	1960	52
.15 Al PILCA	1,980	1970	42
.15 Cu PILCA	7,658	1967	45
.2 Al PILCA	339	1975	38
.3 Cu PILCA	34,633	1966	46
.4 Cu PILCA	2,742	1962	50
25mm Cu PILCA	15	2001	11
35mm Cu PILCA	35	1999	13
35mm Cu PILCA	17	2008	4
70mm Al PILCA	199	1980	32
70mm Cu PILCA	627	1967	45
95mm Al PILCA	7,069	1984	28
95mm Cu PILCA	70	1942	70
120mm Cu PILCA	276	1967	45
150mm Al PILCA	147	1976	36
185mm Al PILCA	2,283	1985	27
185mm Cu PILCA	9,667	1984	28
240mm Cu PILCA	52	2004	8
300mm Cu PILCA	57	1982	30
Other PILCA	87	1944	68
Total Length	94,943 metres		

Figure 3: PVC/Other 400V Underground Cables

Conductor Type	Cct Length (m)	Average Install Year	Average Age (Yrs)
.004 Cu PVC	164	1968	44
.0225 Cu PVC	821	1967	45
.04 Cu PVC	4,754	1973	39
.06 Cu PVC	15,273	1972	40
.1 Cu PVC	265,680	1971	41
.15 Cu PVC	468	1971	41
.4 Cu PVC	518	1984	28
.6 Cu PVC	7	2008	4
16mm Cu PVC	12,335	1993	19
25mm Cu PVC	9,645	1987	25
35mm Cu PVC	14,071	1995	17
70mm Al PVC	996	1983	29
70mm Cu PVC	64,400	1980	32
95mm Al PVC	33,998	1984	28
95mm Cu PVC	3,066	1985	27
120mm Cu PVC	1,866	1994	18
185mm Al PVC	940	2002	10
185mm Cu PVC	3,705	1989	23
240mm Cu PVC	203	1967	45
400mm Cu PVC	33	1980	32
Other PVC	142	1986	26
Other	165,268	1955	57
Total Length	598,352 metres		

Figure 4a: Distribution Cabinet Quantities

Construction	Plastic	Steel	Fibreglass	Unknown	Total
Total	2,869	2,652	4	104	5,629

Figure 4b: Distribution Cabinet – Current Design

These Distribution Cabinets were formerly known as Link Boxes.

Figure 5a: Distribution Box Quantities

Construction	Plastic	Steel	Concrete	Unknown	Total
Total	10,260	738	119	21,418	32,535

Figure 5b: Distribution Box – Current Design

These Distribution boxes were formerly known as Boundary Boxes.

3 ASSET PERFORMANCE

Many system configurations are used for LV underground distribution, depending on the area to be supplied, but generally this is a two-sided system with 400V cables on both sides of the street. These cables are fed from a kiosk distribution substation via multiple feeders, each with a rating of around 250A. The cable is buried directly in the ground. Jointing methods have been changed to improve performance.

The September 2010 and February 2011 earthquakes caused a number of 400V cable faults. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale.

The M6.3 earthquake in June 2011 caused some further damage to our 400V cables but had little impact on our recovery programme.

To date the majority of failure modes have included:

- Third party damage
- Damage of cable during installation or other disturbance causing premature failure.

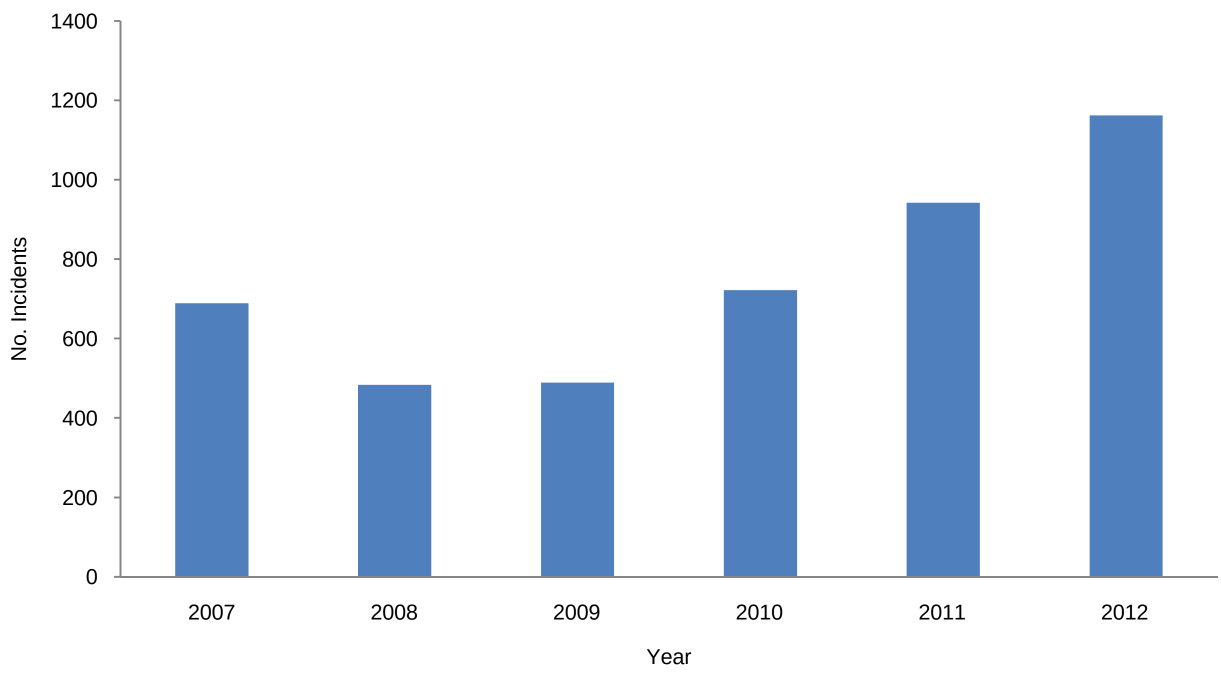
To manage these issues the following actions are taken:

- Proactive promotion of cable locating services to contractors
- Inspection of contractors during cable laying
- New cable is now required to have an orange coloured sheath to allow easier identification.

Figure 6: Number of 400V Underground Cable Faults Per Year

	2007	2008	2009	2010	2011	2012	Total
400V U/G Emerg Maint	689	483	489	722	942	1162	4487

Figure 7: Number of 400V Underground Cable Faults Per Year



4 ASSET CONDITION

4.1 GENERAL

Cable laying has been performed to a good standard and we are not exposed to any great extent from external damage or faulty joints.

We anticipate cables that have been subjected to earthquake stress will have higher failure rates over the next few years as faults develop in sheaths and insulation. To mitigate this we will test the cables in identified areas over the next few years to determine whether maintenance or replacement is required.

The above-ground cable distribution cabinets and boxes are in reasonable condition. We inspect them every five years, with any defects remedied in a subsequent contract.

4.2 CONDITION BASED RISK MANAGEMENT (CBRM) MODELS

In 2011 EA Technology Ltd was engaged to develop a condition based risk management (CBRM) model for our LV underground cable population. This model utilises asset information and engineering knowledge and experience to define, justify and target asset renewal. It provides a proven and industry accepted means of determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model calculates the Health Index (HI) and probability of failure (PoF) of each individual LV underground cable. This effectively gives the cable a ranking which is used when determining the replacement strategy. Note, while the model calculates the asset ranking it is still up to the engineer to prioritise the replacement schedule.

Creating a CBRM model for LV underground cables is a world first for EA Technology. Orion's knowledge of these assets and good data made it possible to build a model that gives an accurate reflection of its LV underground cable population.

We have not yet developed a CBRM model for our above ground cabinets and boxes associated with LV cables.

Figure 8: Explanation of CBRM Health Index Values

CBRM Condition Table

Condition	HI Range	Remnant Life	Probability of Failure	Health Index	Definition
Unknown					Condition unknown or not yet assessed
Bad	10	At EOL (< 5yrs)	High	10 + (9 - 10)	End of serviceable life, immediate intervention required as probability of failure is likely.
Poor		5 - 10 yrs	Medium	(8 - 9) (7 - 8)	Advanced deterioration now reaching the point where failure might well happen
Fair		10 - 20 yrs	Low	(6 - 7) (5 - 6) (4 - 5)	Deterioration occurring, degradation process starting to move from the normal ageing to processes that potentially threaten failure.
Good	0	20yrs +	Very Low	(3 - 4) (2 - 3) (1 - 2) (0 - 1)	Good or as new condition

The following graphs show the Health Index profile of assets, now, in 10 years time if no further investment was made and 10 years time if a specified replacement rate was applied. They illustrate assets that are in good condition (as designated by the green shading), assets that are in fair condition (as designated by the yellow shading) and assets that are in poor/bad condition (as designated by the red shading).

Figure 9: Year 0 Health Index Profile

Category	Length of cable
(0-1)	800,157
(1-2)	626,272
(2-3)	257,015
(3-4)	150,470
(4-5)	87,806
(5-6)	35,581
(6-7)	19,500
(7-8)	0
(8-9)	0
(9-10)	0
(10+)	0
No Result	92,870
Total	**2,069,671**

Figure 10 shows the current condition of our LV underground cables. Figure 12 shows the condition of our LV underground cables in 10 years time if no further investment is made in the replacement programme.

Figure 10: Year 0 Heath Index Profile

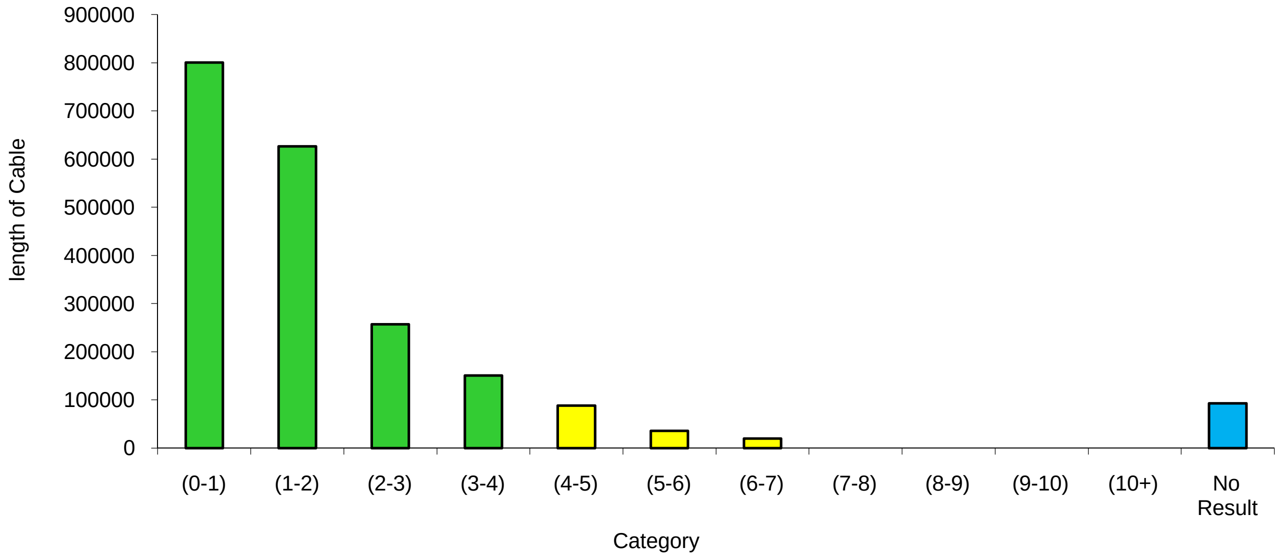
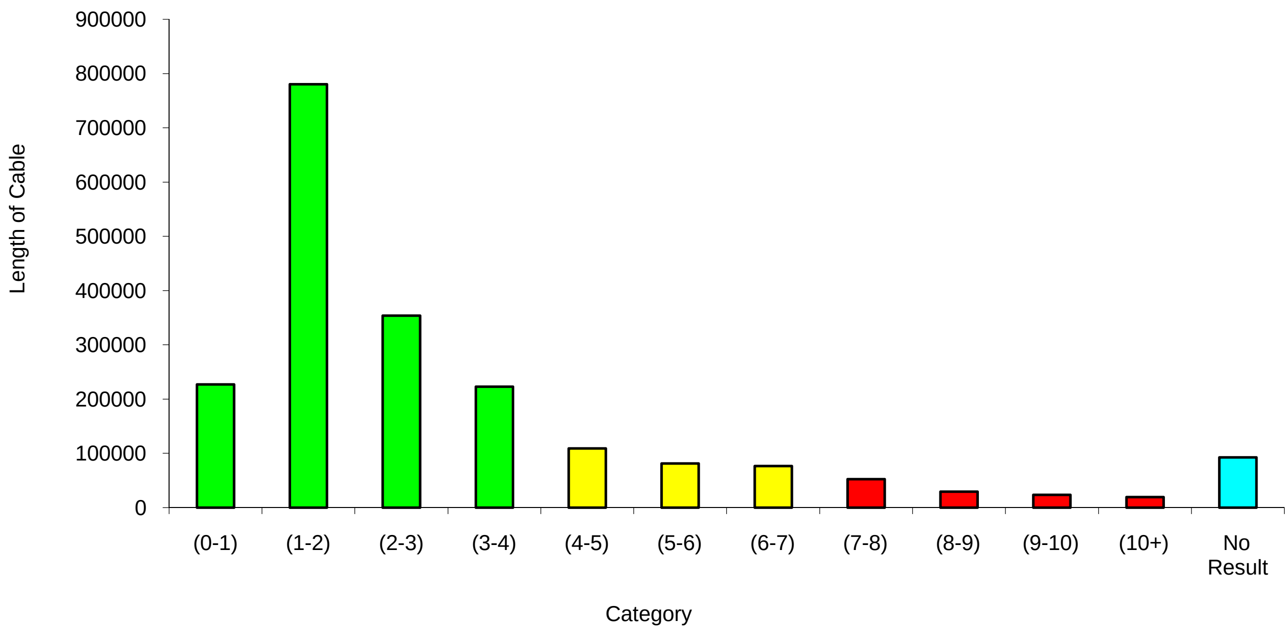


Figure 11: Year 10 Health Index Profile

Category	Length of cable
(0-1)	227,221
(1-2)	780,323
(2-3)	354,209
(3-4)	222,758
(4-5)	108,849
(5-6)	81,166
(6-7)	76,883
(7-8)	52,710
(8-9)	29,454
(9-10)	23,508
(10+)	19,720
No Result	92,870
Total	**2,069,671**

Figure 12: Year 10 Health Index Profile



4.3 HISTORICAL ISSUES

Taped Tee-joints in the Riccarton area were installed on PVC cables in the early 1970s to reduce the number of link boxes (distribution cabinets) and distribution boxes required. These were installed using un-amalgamated tape which through time began to separate and allowed water ingress into the joints which then causes them to fail. These failures generally occurred during the winter in the early 1990s. These joints have since been located and replaced.

There are approx 19,000 service mains t-jointed directly into our distribution network. For reasons of safety these have had the service fuses inspected and any remedial work carried out. They will have distribution boxes installed at the property boundary over time to provide appropriate fusing and isolation.

Compression lugs and connectors were most commonly used in joints and terminations on the LV network. Recently Orion have moved away from using these as it was becoming a frequent occurrence of contractors using the wrong sized lug/connectors on the cables as well as using the wrong sized compression dies which has caused joints and terminations to heat up and fail.

Due to Canterbury high UV exposure from the sun, Orion has found many cable terminations up poles insulation fail over time. This was due to the lack of UV protection on the heatshrink used. Within the last 12 months, Orion has revised the quality of heatshrink allowed on our network and is now using a very highly rated, military standard product to overcome this issue.

The safety risk from exposed switchgear inside our older distribution cabinets is being addressed. This is discussed and budgeted under HV and LV switchgear.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

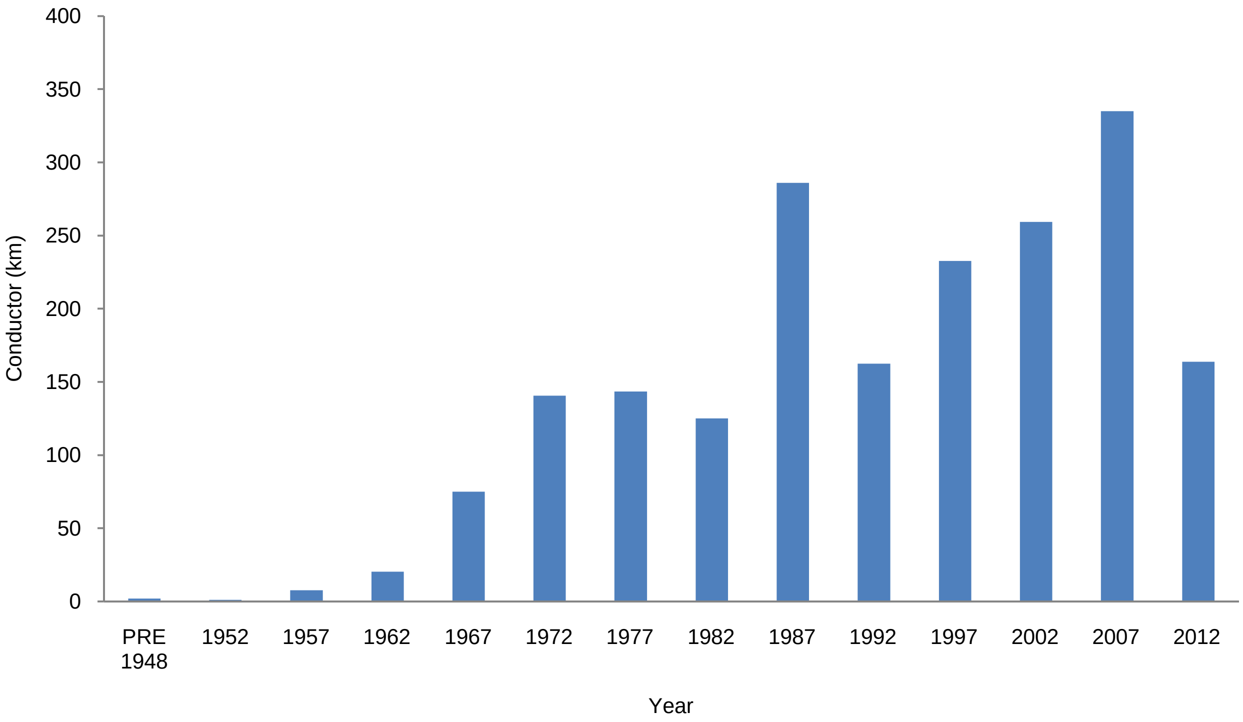
We employ a number of different asset management practices for different asset groups.

- Inspection and Condition Assessment of the LV Underground Network NW72.21.12. The purpose of this specification is to set out an inspection and assessment procedure for LV equipment.
- GIS – Accurately maps the location of our cables and associated above ground assets.
- Shrouding and Earthing programme to minimise the risk of the live exposed metal equipment from contractors and the public as well a long term programme of replacing all live exposed metal equipment with completely insulated DIN equipment to eventually eliminate this risk all together.
- Underground Standard Construction Drawings NW72.21.20. These standards outline the methods of underground construction and maintenance practices.
- Equipment Specs – Distribution Enclosure Installation NW72.22.03, Cables – Installation and Maintenance NW72.22.01. These specifications set out the requirements for materials, intended for use on Orion's underground electricity network.
- Cables Database – This database provides all the relevant cable information for example the cable lengths, joints and time of installations.

5.2 LV UNDERGROUND CABLE LIFECYCLE

The overall condition of these cables is good; however, we are expecting an increase in the failure rates for cables in the eastern suburbs. We have developed a programme to test cables in this area to determine if the expected life of these assets has been affected.

Figure 13: Age Profile LV Underground Cables



5.3 MAINTENANCE PLAN

The condition of this asset is monitored through:

- An above ground five-yearly visual inspection programme of the cabinets and boxes and their cable terminations.

Maintenance work planned is as follows:

- Insulation is being upgraded on cables connected to the overhead system, where insulation is identified as degraded due to the effects of ultra violet light. This insulation project has also been upgraded to a higher specification of cover to withstand New Zealand's higher than average UV.

- To remedy safety issues old cast iron cable termination boxes with heat shrink are being replaced.

- Installation of perspective plastic covers over all exposed LV equipment to provide an extra barrier of protection for the general public.

5.4 REPLACEMENT PLAN

Prior to the earthquakes, we did not have a replacement programme in place for any of our LV underground network. As a direct result of the seismic events we have allowed to replace approximately 4km of LV cable per year for the next ten years. At the time of writing, we have not yet developed a detailed replacement programme as we are still analysing our failure models and the areas where they are occurring.

5.5 DISPOSAL PLAN

We have no plans to dispose of any of this asset, other than minor disposals associated with changes and rearrangements in the network. Cables which are taken out service are generally kept in the ground with each end sealed to prevent any moisture ingress into the cable and deterioration to the cores and insulation.

No decision has been made as to the fate of assets in the red zones.

5.6 CREATION / ACQUISITION PLAN

We will install additional LV cables as a result of the following:

- Conversion of reticulation from overhead to underground as directed by the city and district councils
- Developments as a result of new connections and subdivisions.

5.7 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.8 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

6 EXPENDITURE

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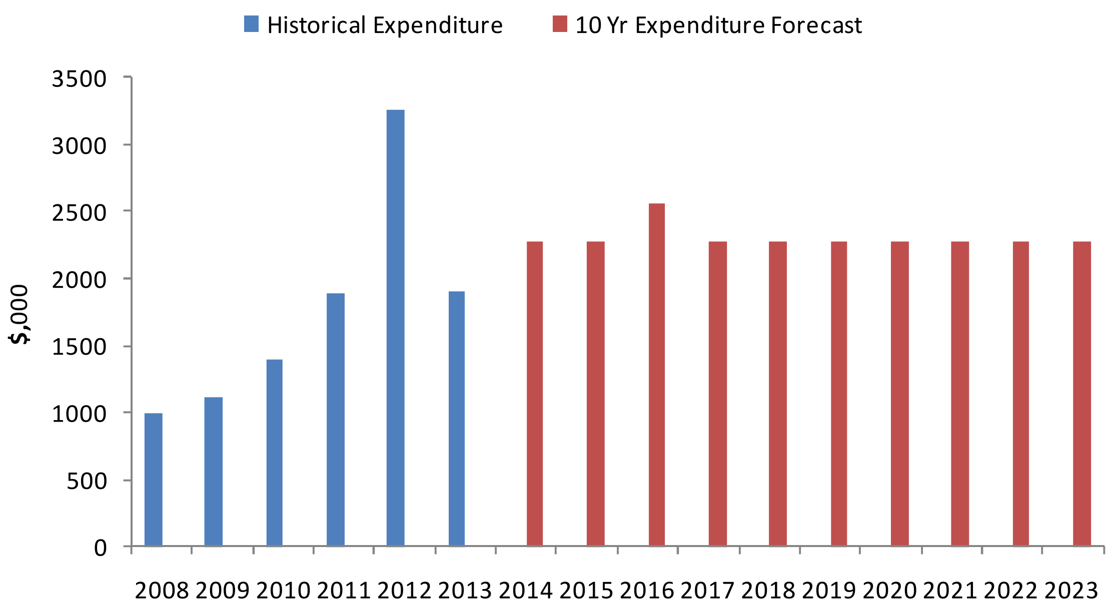
Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 16: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 17: LV Underground Cable - Historical Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	347	385	636	486	231	720
Non-Scheduled	116	255	227	142	177	130
Emergency	535	472	537	1254	2851	1050
Total	**998**	**1112**	**1400**	**1882**	**3259**	**1900**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 18: LV Underground Cable - Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	720	720	720	720	720	720	720	720	720	720
Non-Scheduled	130	130	130	130	130	130	130	130	130	130
Emergency	1420	1420	1710	1420	1420	1420	1420	1420	1420	1420
Total	**2270**	**2270**	**2560**	**2270**	**2270**	**2270**	**2270**	**2270**	**2270**	**2270**

Our scheduled maintenance of LV underground cables is tendered as part of our contracting model.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 19: Historical and Forecast Expenditure

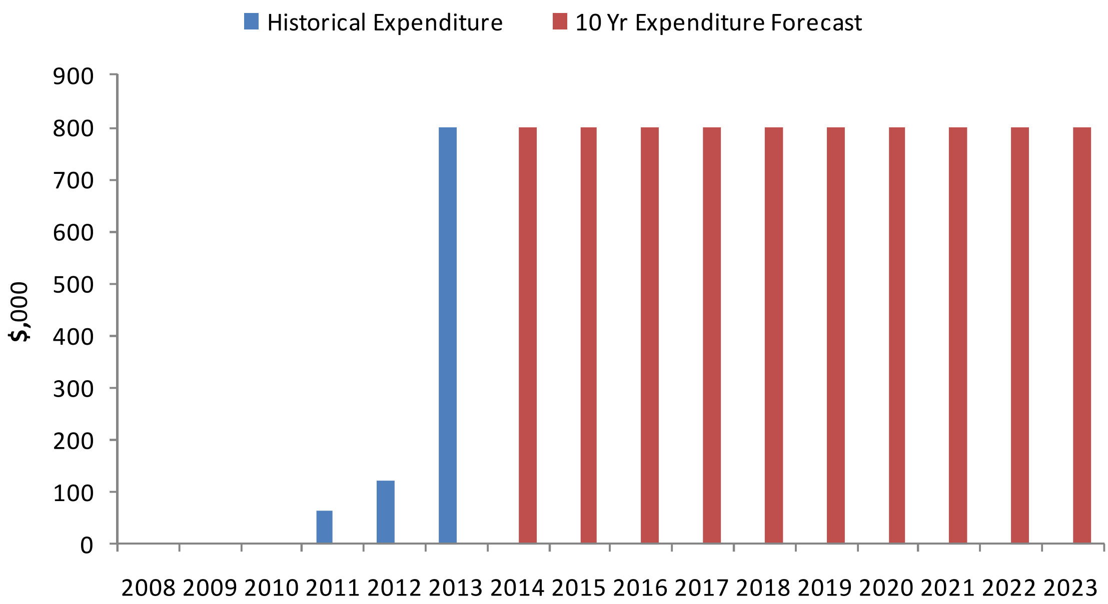


Figure 20: Historical LV Underground Cables Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	0	0	0	65	123	800
Total	**0**	**0**	**0**	**65**	**123**	**800**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 21: LV Underground Cables Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	800	800	800	800	800	800	800	800	800	800
Total	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**

As mentioned in Section 5.4, we have allowed for the replacement of approximately 4km of LV underground cable per year for the next ten years. As we analyse our faults data, we will refine our replacement programme as appropriate.

Communication Systems

Asset Management Policy

NW70.00.34

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1 INTRODUCTION

Communication systems are an essential ancillary service assisting with the operation of our distribution network. These systems provide both voice and data communication and allow contact with operating staff and contractors in the field and remote indication and control of network equipment. They allow the network to be operated more efficiently with a reduced number of staff while minimising the effect of faults on customers.

This document covers each of our communication system categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life.

2 ASSET DESCRIPTION

2.1 VOICE COMMUNICATION SYSTEMS

2.1.1 Private Telephone Switch

This switch is configured in a campus environment with all platforms duplicated except voice recording and contact centre. The system can operate with a failure of either campus location. In addition a tested disaster recovery process is in place should this switch network totally fail.

We also make extensive use of public cellular telecommunications systems for day to day voice communications with staff.

2.1.2 VHF Analogue Radio etc.

Voice radio is provided by a number of linked and same-frequency VHF hilltop radio repeaters. Three linked, different frequency repeaters provide coverage to the greater Christchurch and surrounding rural areas. One same-frequency linked repeater provides coverage in the Akaroa and Banks Peninsula area and an unlinked same-frequency solar powered repeater provides coverage in the Arthur’s Pass and upper Rakaia river areas. A project is underway to place the same-frequency repeaters on their own frequency, and all will be linked by UHF radio with the feature to link or unlink each repeater controlled from our control centre.

Prior to winter 2012 the Hamilton Peak site building and antenna structure were jointly upgraded by all site partners. Orion holds a 30 year concession from DOC for site occupancy.

Our network operators’ vehicles are equipped with back-to-back radios. This allows the vehicle radio to be used when they leave their vehicle with a low power hand-held radio for communication. Associated with this is automatic vehicle location and lone-worker alarm generation. All these tools help ensure the safety of this group of staff.

2.2 DATA COMMUNICATIONS SYSTEMS

2.2.1 SCADA Analogue UHF Radio

The SCADA analogue UHF radio system consists of a number of dedicated UHF repeaters sited on various hilltops utilising licensed frequencies. The number and location of these repeaters is dictated by their coverage and the number of substations they need to communicate with. Communication from the SCADA master station to the repeaters/substations is by UHF radio.

Note: A very small number of micro SCADA RTUs share the VHF voice repeater network. These RTU’s are progressively being transferred from the analogue radio system to the IP system.

2.2.2 SCADA Analogue Communication Network

This is comprised of two communication cable technologies:

- Audio frequency shift keying (AFSK) modem technology - this has a long reach but a low data transfer rate of 1.2kB

- Low frequency modem communication - while this has a higher data transfer rate its reach is typically slightly less than the AFSK technology but data rates are typically 9.6kB

2.2.3 SCADA and Engineering IP Network

This network provides IP based communication to all zone substations and some pole-top equipment. The system utilises a combination of Symmetric High Speed Subscriber Line (SHDSL) modems running over Orion copper communications cables (see NW70.00.28) and UHF IP radio. The network is configured in a combination of rings and mesh topology to provide redundant paths to most zone substations.

In the urban area where SHDSL modems are used, dedicated routers are installed, while the IP radios provide native IP routing functions. A routing protocol (OSPF) is run on the network to allow automatic selection of optimum routes with automatic routing round link failures.

2.2.4 UHF IP Radio System

The UHF IP radios use high spectral efficiency radios operating in licensed UHF bands. The radios can be used for IP traffic only in point to multipoint mode with base stations located at hilltop sites or in point to point mode with bandwidth shared between protection signalling and IP traffic.

Point to multipoint base stations have been established at three locations covering the Canterbury Plains and Banks Peninsula

Point-to-point links have been installed in conjunction with network protection upgrades.

Together these communication links form a spoke and hub network centred on the base stations with links between remote stations via point-to-point links shared with protection signalling.

2.2.5 SHDSL IP System

Where copper communication cables are available, which is generally in the urban area, IP communications have been provided using SHDSL modems providing point-to-point IP links between substations, typically running at 1 Mb/s. The various urban links are arranged in four rings to provide full communications redundancy to each substation. This equipment is fully protected against EPR (Earth Potential Rise) voltages.

2.2.6 Cellular IP Systems

There is one zone substation, a number of 11kV regulators and various power quality monitors which are served by public cellular communications.

All mobile PDA devices, and data connectivity to vehicles is also provided by the public networks.

Figure 1: Communication System Components

Asset	No. Units	Ave Age (yrs)	Nominal Life (yrs)
Cable modems	78	5	8 to 10
Voice radios	110	5	8
Cellular modems / HH PDAs	87 / 39	4	5
IP data radios	85	3	8
Radio antennae	80	3	8
Antenna cable	150	3	15
Communication masts	34	3	40
Routers/switches	35	5	8
Telephone switch	2	-	Continuous maintenance upgrades 3 year cycle

3 ASSET PERFORMANCE

As electronic control and monitoring equipment installed in substations has evolved, we have reached the point where older analogue communication systems running at low speed and dedicated to SCADA (telemetry) are no longer appropriate. We are well into a replacement programme converting communications to our substations to standard IP based network technology which provides both SCADA and engineering access over a common communications system.

Communications speeds provided by the various technologies vary from 1.2 Kb/s or 9.6 kb/s on older analogue links to 64 kb/s, 250 kb/s or 1 Mb/s on IP radio and SHDSL cable links. While 1.2 kb/s or 9.6 kb/s are adequate for SCADA, 64 kb/s is at the lower end of what is acceptable for engineering access.

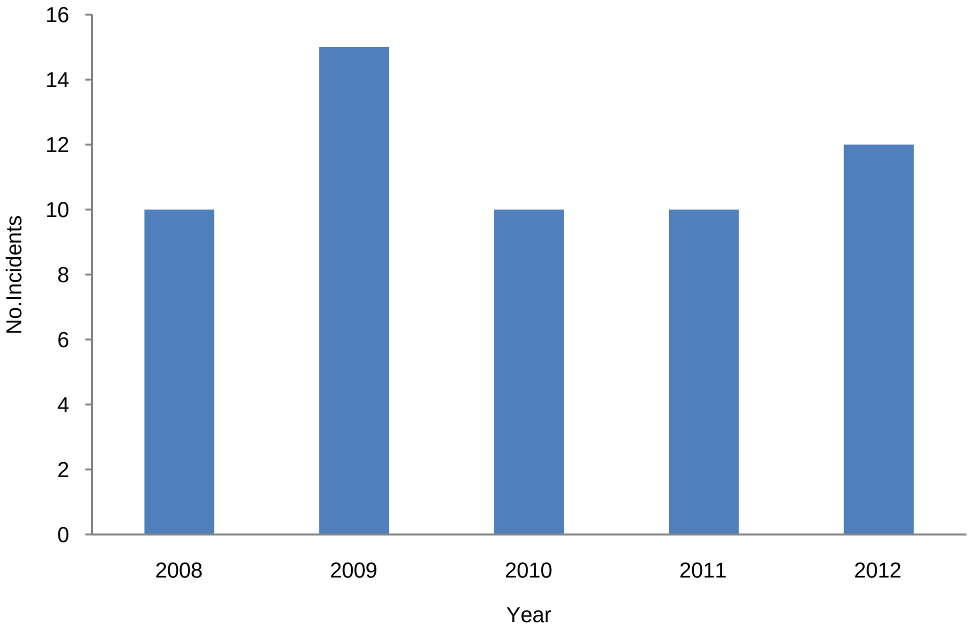
The cable-based network provides reasonable speed but is only available where copper cable is available, i.e. generally zone and network substations. Point-to-point IP radio operates at 64kb/s; this is just adequate and is also only generally available in conjunction with zone substation sub transmission protection systems. The point-to-multi-point IP radio system operates at a gross speed of 250kb/s but this must be shared with all outstations and is limited to approximately 100 remote stations per base station.

All technologies perform adequately, however those utilising copper cables are subject to faults on cables which have been negatively impacted in eastern Christchurch by the recent earthquakes.

Figure 2: Number of Communication Assets Replaced Due to Faults

Asset	2007	2008	2009	2010	2011	2012
Cable modems	-	-	3	-	-	-
Voice radios	-	-	-	-	-	2
Cellular modems / HH PDAs	-	10	10	10	10	10
IP data radios	-	-	2	-	-	-
Radio antennae	-	-	-	-	-	-
Antenna cable	-	-	-	-	-	-
Communication masts	-	-	-	-	-	-
Routers/switches	-	-	-	-	-	-
Telephone switch	-	-	-	-	-	-
Total	**0**	**10**	**15**	**10**	**10**	**12**

Figure 3: Communications Performance



4 ASSET CONDITION

4.1 GENERAL

The older analogue radio systems being replaced by the new IP radio system are still serviceable but are becoming more challenging to service. Part of the migration of SCADA communications to modem and HDSL modems is driven by the condition of older communications hardware.

Currently the new IP based equipment is on average no older than five years and is in good condition.

Our business telephone switch is a hybrid TDM and IP system. It is current with supported hardware/software releases.

5 ASSET MANAGEMENT PRACTICES

5.1 COMMUNICATIONS LIFECYCLE

While many components of the communications system have a tax book life of 36 months, Figure 1 shows the expected nominal life of the various communications components.

5.2 MAINTENANCE PLAN

The performance of our UHF stations used to communicate with the SCADA equipment is continually monitored. We ensure the transmitters comply with the Ministry of Economic Development Radio Spectrum regulations.

We have maintenance contracts with several service providers to provide ongoing support and fault resolution. A maintenance contract for our telephone switch is in place. Maintenance is carried out on a monthly basis.

SHDSL modems, IP radios and other communications equipment are monitored with maintenance scheduled when needed.

5.3 REPLACEMENT PLAN

Because of the rapid improvement in technology, communications equipment has a relatively short life and thus equipment is not normally renewed but is replaced with more modern technologies as part of the Creation/Acquisition Plan.

5.4 DISPOSAL PLAN

All electronic equipment is disposed of in accordance with current environmental recommendations. In some cases surplus equipment is donated to organisations that support Civil Defence or Search and Rescue communications, or where practicable it is offered to organisations that still use the equipment.

5.5 CREATION / ACQUISITION PLAN

5.5.1 Completion of IP Network

Installation of the IP network is virtually complete. Some older analogue links are still in place but will be progressively upgraded, generally when the associated network primary equipment (reclosers, switches etc.) is replaced. This should take place over the next few years. The installation of additional equipment at Hamilton Peak to provide coverage in the upper Waimakariri Basin is planned for the next few years.

5.5.2 Head Office Relocation

The relocation of Orion's head office to Wairakei Rd will allow the two core server sites to be properly separated. As part of this move additional SHDSL links will need to be installed between Wairakei Rd and the outer ends of the urban IP rings. In addition the base station for the backhaul from the Roundtop point-to-multipoint base station will be relocated to Wairakei Rd. These changes will provide route diversity between the core servers and the field stations.

5.5.3 Mobile and Future 'Smart Grid' Communications

Mobile data communications is currently provided using public cellular networks.

The SCADA and engineering communications systems that we have now installed are suitable (possibly with the addition of additional base stations) for up to some low 100s of remote stations. So called 'smart grid' technologies will require some 1000's of remote stations which is beyond the capabilities of our existing infrastructure. This capability could be provided using public cellular technologies.

Experience during major events, e.g. earthquakes, snowstorms etc., is that public cellular communication networks frequently are not very reliable just when good communications are most essential. In addition cellular coverage for mobile data communications can be problematic in rural areas.

Technologies are available to provide these communication services in-house but currently radio spectrum is not available. We are watching the allocation of spectrum for broadband services for PPDR (Public Protection Disaster Recovery) and Critical Infrastructure Operators. In an ideal situation a wide area private broadband network would reduce our reliance on public cellular providers. In the meantime we will continue to use public cellular networks for mobile data communications and 'smart grid' trials can progress using public cellular networks but with the intention that if and when spectrum becomes available, Orion should consider installing an in-house communications system to support these devices/services.

5.5.4 Voice Radios

It is Orion's intention to retain basic voice radio communications and specifically not migrate to managed protocol technologies. This may see the adoption of more CTCSS (Continuous Tone Coded Squelch System) or even a migration from analogue to digital transmissions but this will still be seen as our "belts and braces" simple but reliable communications backstop.

5.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.7 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.8 RISK ANALYSIS

The SCADA IP network is configured in a mix of rings and mesh with multiple paths to almost all zone substations and major communications nodes. As such the network is very fault tolerant and can in many cases withstand multiple link failures without losing significant connectivity.

The recent disasters have focussed our attention on dual rather than backup systems with attention to quality radio installations with well engineered links and wherever possible maintaining significant radio signal fade margins for all radio paths.

The most significant risk is the reliance on public cellular providers irrespective of whose network is used. Our experience is that the public providers have different business drivers than our own when operating in a Disaster Recovery mode. While we are researching our options, radio spectrum availability will dictate what can be achieved.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Figure 4: Historical and Forecast Expenditure

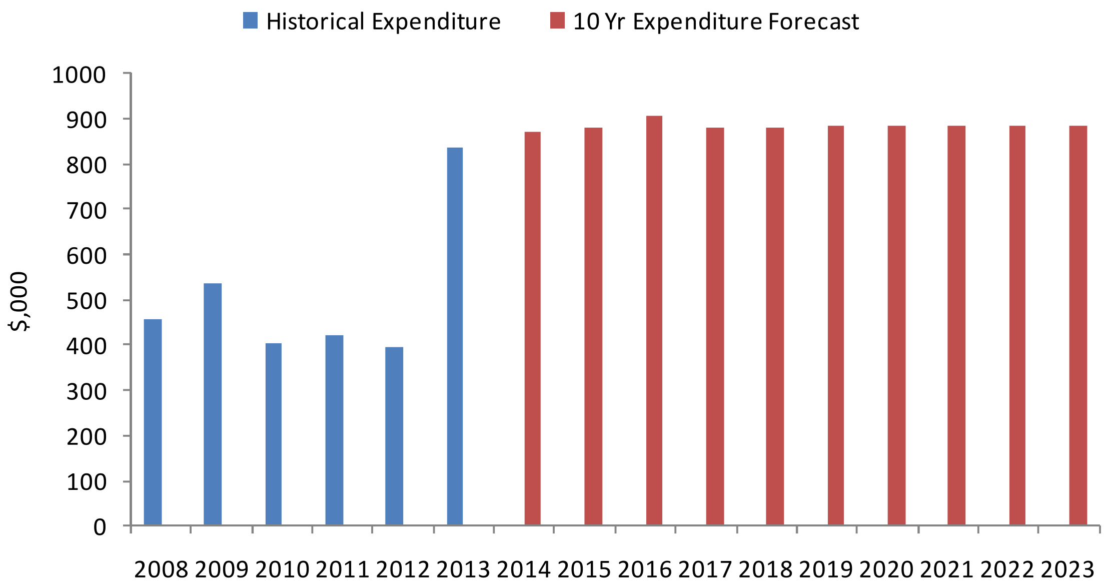


Figure 5: Historical Communication Systems Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	258	387	169	216	271	665
Non-Scheduled	75	45	123	117	39	80
Emergency	123	103	113	87	85	90
Total	**456**	**535**	**405**	**420**	**395**	**835**

Figure 6: Communication Systems Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	670	680	680	680	680	680	685	685	685	685
Non-Scheduled	80	80	80	80	80	80	80	80	80	80
Emergency	120	120	145	120	120	120	120	120	120	120
Total	**870**	**880**	**905**	**880**	**880**	**880**	**885**	**885**	**885**	**885**

6.2 REPLACEMENT EXPENDITURE

Figure 7: Historical and Forecast Expenditure

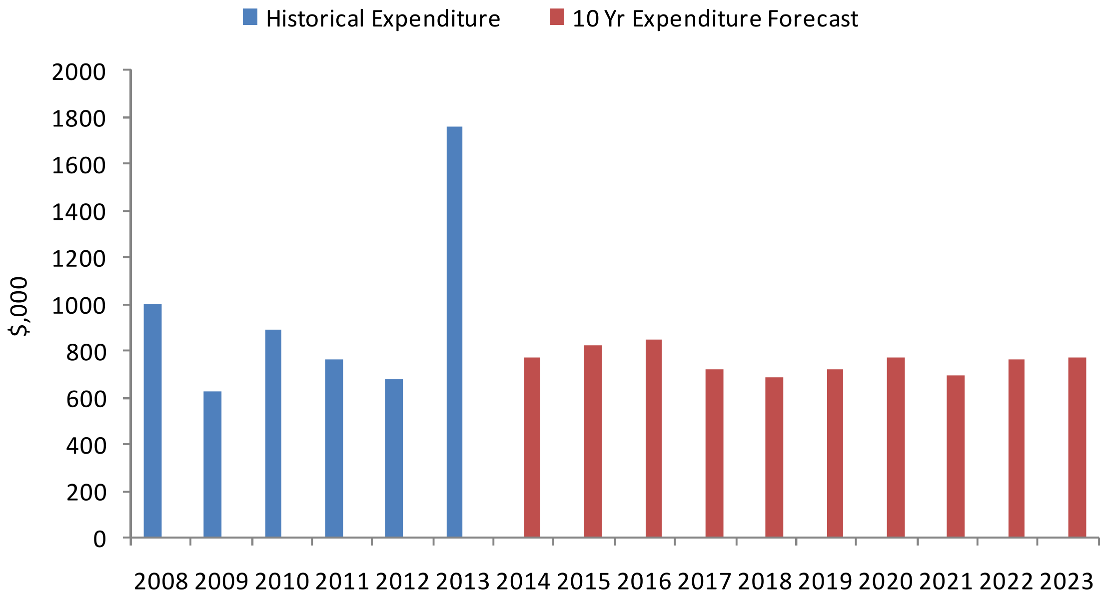


Figure 8: Historical Communication Systems Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	999	627	895	762	676	1765
Total	**999**	**627**	**895**	**762**	**676**	**1765**

Figure 9: Communication Systems Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	775	825	845	725	685	725	775	695	765	775
Total	**775**	**825**	**845**	**725**	**685**	**725**	**775**	**695**	**765**	**775**

Distribution Management Systems

Asset Management Report YE 2012

NW70.00.36

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1 INTRODUCTION

This document covers our distribution management system (DMS) and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from this system.

2 ASSET DESCRIPTION

2.1 GENERAL

A DMS is a collection of applications designed to monitor and control the entire distribution network efficiently and reliably. It acts as a decision support system to assist the system control operators and field operating personnel with monitoring and control of the electricity distribution system. Improving the reliability and quality of service in terms of reducing and minimizing outage time, maintaining acceptable frequency and voltage levels are the key deliverables of a DMS.

We have had different forms of supervisory control and data acquisition systems (SCADA) on the network since the early 1970s. These systems have traditionally been based on a master station (central control centre) communicating with the remote terminal units (RTU) at remote sites throughout the network thus providing real time information from a small portion of the network – generally zone substations.

A DMS takes basic SCADA to the next level by integrating SCADA real time information from the field with a comprehensive network operating model with full connectivity, including customer connections and operated in near real time. By combining telemetered information from the SCADA system and field operator switching actions with the locations of outage calls from customers, a rule engine is used to predict the locations of outages. Based on this information the DMS can assist the system control operators to restore power by helping automate the isolation and restoration procedures.

This overall system is a key tool for monitoring and operating our electricity network. It monitors network assets in real time and through alarms notifies of potential or actual equipment failure. In the event of a storm or major event it enables us to better coordinate our efforts to restore power.

2.2 NETWORK MODEL

At the heart of the DMS is a comprehensive network model (including all lines, cables switches and control devices, etc.) with full connectivity operated in near real time.

This system is used to manage switching processes on the network. It facilitates the management of work planning, safety associated with switching and associated documentation. It also maintains switching logs.

A full graphics ‘human machine interface’ (HMI) is used to display the network model and provide operator interaction with the system.

2.3 SCADA

A comprehensive SCADA master station is tightly integrated into the DMS and provides tele-metered real-time data to the network connectivity model.

2.4 DMS APPLICATIONS

2.4.1 Outage Management System (OMS)

The OMS allows for the identification, management, restoration and recording of faults. In the case of a fault or event, the OMS assists in determining areas affected by outages utilising predictive algorithms. This allows us to give our customers better information regarding what has occurred and when we expect to be able to respond.

2.4.2 Mobile Despatch

Mobile network operators are equipped with personal digital assistant (PDA) devices connected to the cellular network. Switching instructions are sent directly to the PDAs from the DMS for execution by the operator. As they carry out the switching they confirm the steps are completed and the network model is updated with the changes in close to real time.

2.4.3 Historian

An historian collects stores and provides analysis tools for time series data – binary and analogue. The basic DMS system is equipped with only rudimentary time series storage capabilities and thus a separate historian is required.

The time series data stored in the historian is used by various applications throughout the organisation for planning, network equipment condition analysis and display of network operating performance such as reliability.

2.4.4 Real-time Load Flow Analysis

Because the DMS has access to large amounts of real time field data and maintains a real time connectivity model, it is possible to carry out a near real time load flow calculation on the network model. The load flow can be used to predict network operating conditions at locations where no telemetered data is currently available (state estimation) and can also be used to carry out 'what if' calculations to predict the effects of modified network topologies/switching.

2.4.5 Information Interfaces to the Business and Connected Customers

The DMS contains a large amount of information about the state of the distribution system. Applications can be written which extract this data from the DMS and historian and presented as reports or data on web pages for consumption within the organisation or to the public.

3 ASSET PERFORMANCE

The DMS has been incrementally installed and upgraded over the past four years and has recently undergone a major upgrade to install the OMS. The system has been specified and installed with a very large amount of spare capacity and performance.

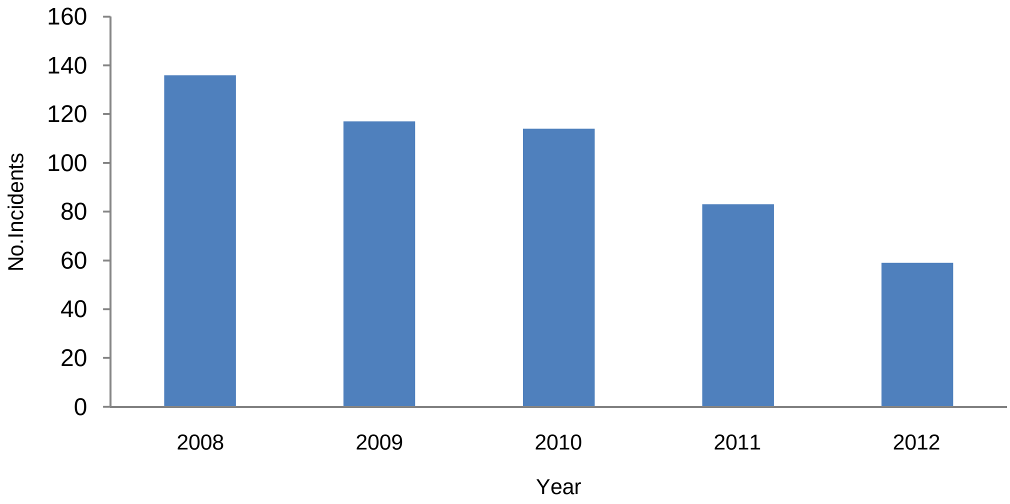
The DMS is a critical business application and as such runs on three servers operating in real time replication. The hardware associated with the servers is duplicated in geographically separate environmentally suitable sites. The sites also have un-interruptible backup power supplies consisting of a UPS and a generator.

Separate servers are installed for testing new software releases and training.

3.1 REMOTE TERMINAL UNITS

We have a number of older RTUs in our network which are no longer supported by their manufacturer. We hold enough spares to cover these units for maintenance purposes and they are performing adequately. These units are progressively being replaced as other upgrades (switchgear replacement etc.) take place at those locations. The remainder of our units are performing satisfactorily, are fully supported by their vendors and are capable of meeting the increased requirements of the new master station.

Figure 1: SCADA RTUs Performance



4 ASSET CONDITION

4.1 GENERAL

While some of our older RTUs no longer have manufacturer support, their condition is satisfactory. Those units that do not meet our current operating criteria have been targeted for removal.

The rest of this asset group is in good condition and proving reliable.

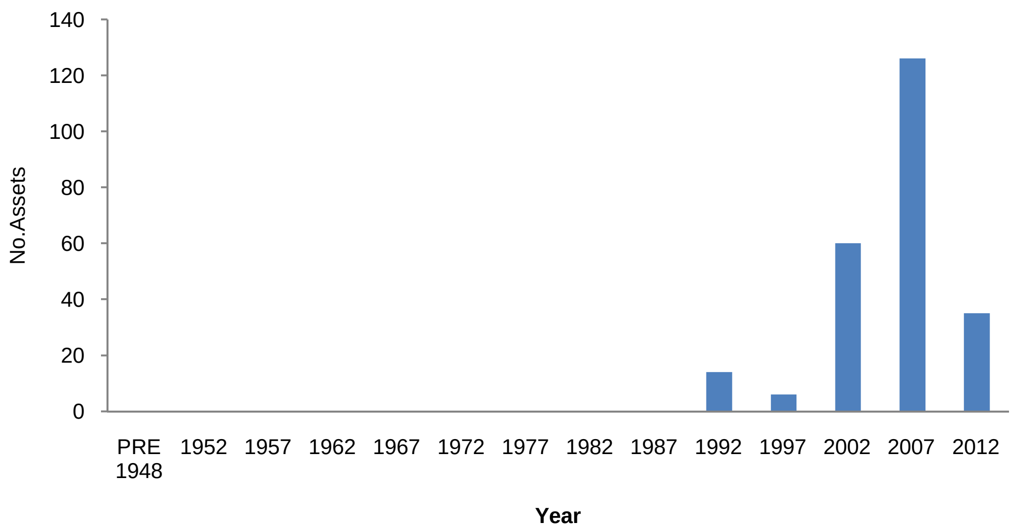
5 ASSET MANAGEMENT PRACTICES

5.1 DISTRIBUTION MANAGEMENT SYSTEMS LIFECYCLE

The fully functional DMS is less than one year old. It should be expected that the software should be current (with a periodic software upgrade lifecycle of three years) for a minimum of 15 years.

The underlying hardware is standard commercial grade computing equipment with a typical replacement lifecycle of three to five years.

Figure 2: Age Profile - SCADA RTUs



5.2 MAINTENANCE PLAN

The DMS components and RTUs are maintained on an as-required basis, with component availability the main criteria. This system is supported internally by our own staff and with a maintenance agreement with the vendors.

Inspections we carry out include:

- weekly general operational checks of equipment software
- annual detailed check of hardware and software systems
- annual operational check of all RTU controls and indications.

Our budgeted maintenance costs are shown in section 6.1 – Maintenance budgets/control systems (this also includes communications and load management systems).

5.3 REPLACEMENT PLAN

DMS and RTU hardware capabilities, age and maintainability is reviewed annually and assessment made of equipment that needs to be programmed for replacement/renewal.

5.4 DISPOSAL PLAN

We dispose of equipment as part of the replacement programme.

5.5 CREATION / ACQUISITION PLAN

The basic DMS is now fully functional with the SCADA, network model and OMS installed and operational. It is planned for an historian to be installed during the latter half of 2012. Various business and customer interfaces will be developed over the next few years as resources permit. We also plan to configure and install an on line load flow at some point in the next couple of years.

5.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.7 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.8 RISK ANALYSIS

The DMS consists of three database servers consisting of DMS/database server pairs. To provide physical diversity, two of these servers are located in one data centre and the third is located in the second geographically separated data centre.

Users' terminals normally connect to the most lightly loaded server; however the system can operate satisfactorily on a single server, only requiring the user terminals to reconnect to the remaining server(s) during a failure.

The front end communications processors are spread between the two data centres and although not fully duplicated, in the event of loss of one data centre, the services could be quickly transferred to the remaining centre.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Figure 3: Historical and Forecast Expenditure

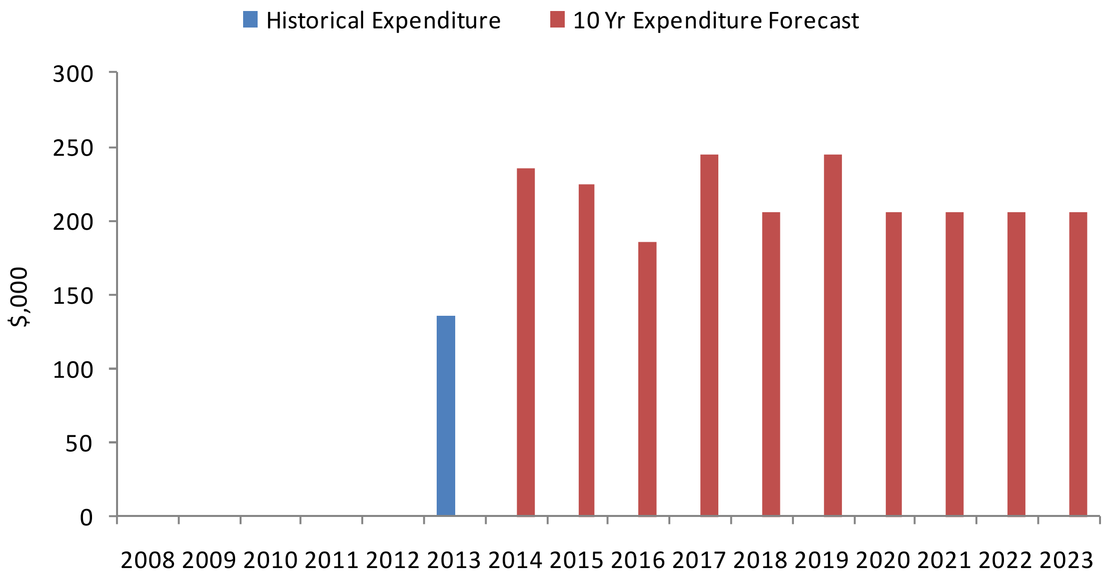


Figure 4: Historical DMS Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	0	0	0	0	0	135
Total	**0**	**0**	**0**	**0**	**0**	**135**

Figure 5: DMS Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	235	225	185	245	205	245	205	205	205	205
Total	**235**	**225**	**185**	**245**	**205**	**245**	**205**	**205**	**205**	**205**

6.2 REPLACEMENT EXPENDITURE

Figure 6: Historical and Forecast Expenditure

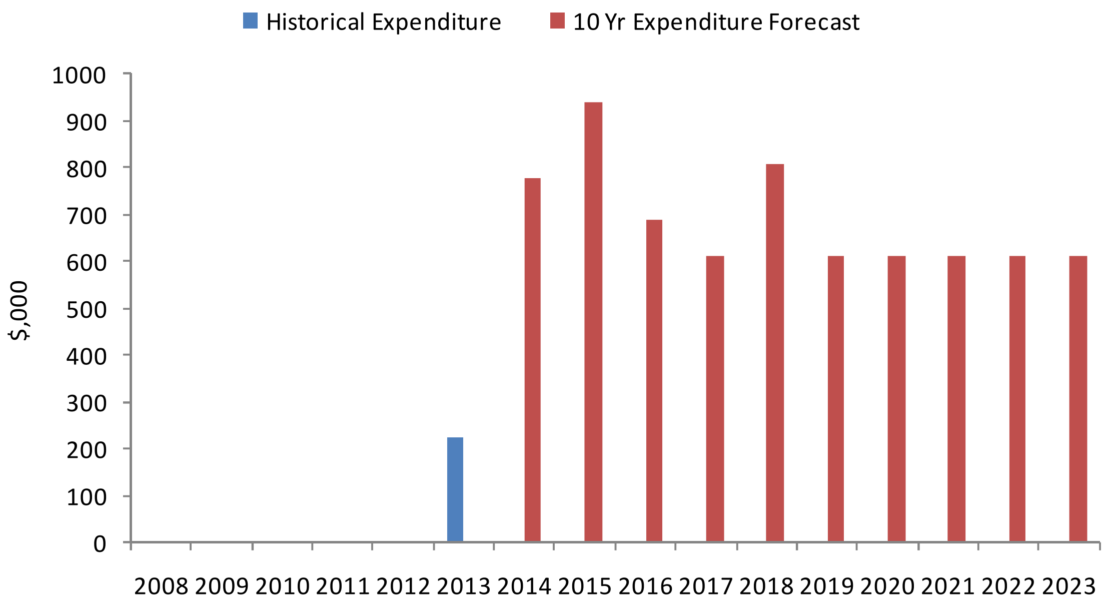


Figure 7: Historical DMS Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	0	0	0	0	0	225
Total	**0**	**0**	**0**	**0**	**0**	**225**

Figure 8: DMS Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	780	940	690	610	810	610	610	610	610	610
Total	**780**	**940**	**690**	**610**	**810**	**610**	**610**	**610**	**610**	**610**

Load Management Systems

Asset Management Report YE 2012

NW70.00.37

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1 INTRODUCTION

This document covers our load management system and details the criteria and asset management practices used to ensure we obtain effective performance and an acceptable level of service.

2 ASSET DESCRIPTION

2.1 GENERAL

Our network load management system is used to control loads on Orion's network and also seven other networks which are part of the Upper South Island load management group, thus deferring energy consumption and peak load, and therefore network investment. Its other main function is tariff switching. It works by injecting an audio frequency signal into the power network that is acted upon by relays installed at the consumer's connection point. The relays in Orion's network are owned by the retail traders, with the exception of some 2,000 used for streetlight control. These relays are owned by Orion.

The load management system is comprised of an Orion master station, an Upper South Island master station, RTUs at each GXP and two injection systems.

2.2 ORION LOAD MANAGEMENT MASTER STATION AND RTUS

The Orion load management master station is a SCADA system that runs independently of the network operational SCADA system. The master station consists of two redundant database servers and two communication line servers (CLS) on dedicated hardware. The load management software utilises algorithms specifically developed for Orion.

Loading information for the system is from dedicated RTUs located at GXPs and zone substations. Sources of information and communication paths are duplicated where reasonably feasible.

2.3 UPPER SOUTH ISLAND LOAD MANAGEMENT SYSTEM

The Upper south Island Load Management System is a dedicated SCADA system that runs independently of Orion's load management and network operational SCADA systems. The system consists of two redundant servers that take information from Orion's, Transpower's and seven other Upper South Island distributors' SCADA systems, monitors the total Upper South Island system load (retrieved from Transpower) and sends commands to the various distributors' ripple control systems (including Orion's) to control this total load to a predefined target.

2.4 RIPPLE INJECTION SYSTEM - TELENERG 175 HZ

This system operates within the urban 66kV subtransmission network and is the major ripple injecting system controlling the load of approximately 150,000 consumers. It is made up of more than 25 small injection plants connected via circuit breakers to the 11kV network at individual 66/11kV zone substations and Christchurch urban 33/11kV zone substations.

These plants can operate independently with all 'fixed-time' signalling carried out from a timetable stored in the individual plant controller. All 'anytime' signalling is controlled by the SCADA system via individual controllers in response to commands from the load management system running on the master station.

The plants are relatively small and, apart from the coupling cell itself, consist of interchangeable 19 inch rack mounting equipment for which spares are held. A complete coupling cell is also kept as a spare. It is also possible in an emergency for a single plant to signal an adjacent area.

2.5 RIPPLE INJECTION SYSTEM - ZELLWEGER DECABIT 317 HZ

The Decabit system operates within the 33kV subtransmission network and is made up of five plants connected to the 33kV system via air break isolators and protected by circuit breakers, at Springston (two plants), Moffett, Hornby and Hororata zone substations. Back-up for the injection plants themselves is provided by pairs of plants in each GXP supply area. Two plants are installed at Springston and the plants at Hornby and Moffett provide back-up for each other. One plant of each pair is kept as a cold standby. There is no spare plant for Hororata; however, it would be possible in an emergency to relocate one of the Springston plants to Hororata.

With the ability to transfer load between the urban 66/11kV and 33/11kV systems, 11kV Telenerg ripple plants have been installed at Hornby, Moffett, Shands, Sockburn, Harewood and Prebbleton zone substations. It is anticipated that the 33kV Decabit plants will be removed from service within the next 10 years once ripple relays within the area have been re-coded or replaced.

With the installation of the rural 66/11kV substations it has become necessary to install a small 11kV Decabit ripple plant at each of these substations. These plants are connected to the network via indoor 11kV switchgear. Back-up for the 11kV plants is provided by the 33kV injection system.

Like the urban Telenerg system, each Decabit plant operates independently with all ‘fixed-time’ signalling carried out from a timetable stored in the individual plant controller while ‘anytime’ signalling is controlled by the load management system via individual controllers in response to commands from the load management system running on the master station.

2.6 COMMUNICATIONS

Communications between the Orion load manager and the injection plants is via the IP communications system which provides redundant communications paths to all ripple plants.

3 ASSET PERFORMANCE

3.1 ORION LOAD MANAGEMENT MASTER STATION

The master station is a proprietary database system with full graphics running on industry standard hardware and software. It currently meets the performance requirements for the network load management.

3.2 UPPER SOUTH ISLAND LOAD MANAGEMENT SYSTEM

The master station is a proprietary database system with full graphics running on industry standard hardware and software. It currently meets the performance requirements for the Upper South Island load management system.

3.3 RIPPLE INJECTION SYSTEM - URBAN 175HZ

The 66kV injection system was completely replaced in 2002-2004 with small individual 11kV injection plants. Additional plants have been installed during 2005-2007 in the urban 33kV subtransmission system as 11kV interconnection capacity has been added between the urban 66 and 33kV subtransmission areas.

A larger number of smaller injection plants will significantly reduce the risk associated with a single plant failure as adjacent plants can cover for it. New 11kV plant capacity is matched to the capacity of the zone substation it is connected to. As load growth occurs, additional plants will need to be installed in conjunction with additional zone substation transformer capacity.

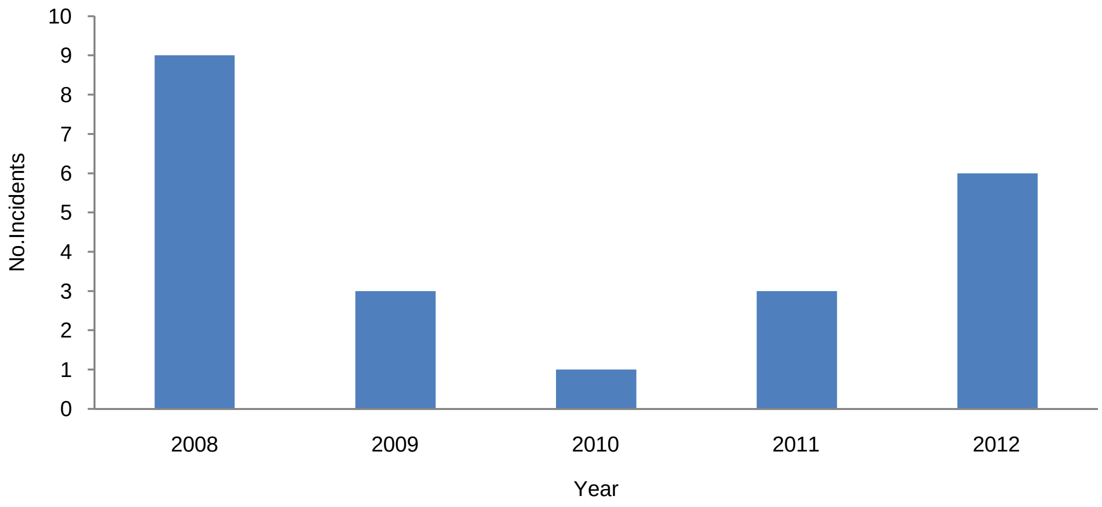
These plants have adequate capacity and performance for the timeframe of this plan.

3.4 RIPPLE INJECTION SYSTEM - RURAL 317HZ

The 33kV ripple injection plants have adequate capacity for the networks they are connected to, and would only have problems if GXP transformers with significantly lower impedance were installed. The existing plants have shown no sign of increased failure rates due to equipment aging and, apart from the Hororata plant, complete cold standby plants are available on both the Springston and Islington 33kV networks. Essential spares are held for the Hororata plant to enable rapid repair in the event of a fault. In a worst-case situation it would be possible to move part or all of one of the Springston plants to Hororata.

11kV, 317Hz ripple plants have been installed at Killinchy, Brookside, Greendale, Te Pirita, Dunsandel, Larcomb, Weedons and Kimberley as these substations were commissioned because these are physically within the existing 317Hz injection area, but are supplied from the 66kV subtransmission system. These are of similar design and supplied under the same contract as those installed as replacements for the urban 175Hz ripple plants.

Figure 1: Ripple Plant Performance



4 ASSET CONDITION

4.1 ORION LOAD MANAGEMENT MASTER STATION

The hardware and software of the master station is now over seven years old and while still running reliably, is not being developed by the vendor (Foxboro) any further. The software will not run on later versions of the hardware platform (Sun Solaris) and support and parts are becoming difficult to source.

The system is very definitely in its twilight years – running a critical Orion function.

4.2 UPPER SOUTH ISLAND LOAD MANAGEMENT SYSTEM

This system is approximately three years old and the hardware is just out of warranty. Given the normal life of such equipment it should be acceptable for a further two to three years before its adequacy needs to be reviewed.

4.3 RIPPLE INJECTION SYSTEM - URBAN 175HZ SYSTEM

The majority of the 11kV injection plants on the 66kV system were installed from 2004, and are expected to have a minimum life of 15 years. The annual maintenance programme checks for possible faults and variations in equipment performance.

4.4 RIPPLE INJECTION SYSTEM - RURAL 317HZ SYSTEM

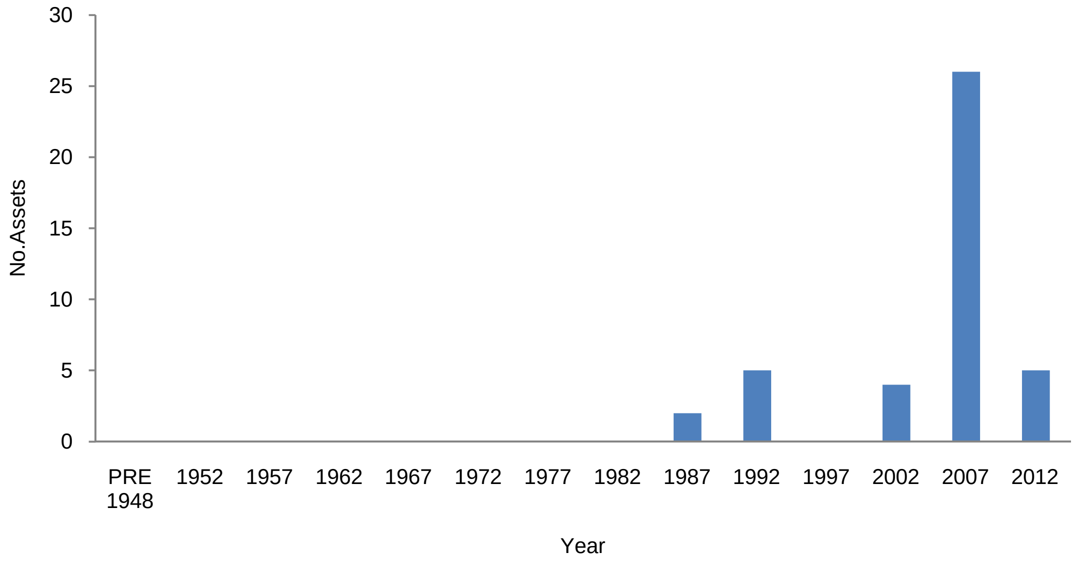
The 33kV ripple plant injection controllers were replaced in 2005 and are expected to have a minimum life of 15 years. The 11kV plants were installed from around 2002 onwards and also expected to have a minimum life of 15 years. The annual maintenance programme checks for possible faults and variations in equipment performance.

5 ASSET MANAGEMENT PRACTICES

5.1 LOAD MANAGEMENT SYSTEMS LIFECYCLE

The Load Management master station hardware is standard computing equipment which typically has a five to seven year replacement lifecycle. The injection plants are a combination of standard distribution and SCADA RTU equipment with a replacement lifecycle of at least 15 years.

Figure 2: Age Profile - Ripple Plants



5.2 MAINTENANCE PLAN

The load management master stations are both covered by supplier maintenance contracts which should be adequate for the next two years.

Our ripple master maintenance programme consists of a daily operational check during the winter period and a weekly operational check during summer. This is supplemented by an annual hardware maintenance programme similar to that performed on the SCADA master stations. The complexity of the software and availability of technical support increase the difficulty and cost of maintaining the master station system.

Injection plants have a quarterly operational check as well as an annual inspection that includes measurement of installed capacitors and detailed tests on the inverter. If the plant coupling cells are found to have drifted they are retuned. Dusting and physical inspections are considered part of the annual maintenance.

5.3 REPLACEMENT PLAN

5.3.1 Orion and Upper South Island Load Management Master Stations

The adequacy of the Upper South Island load management master station hardware will be due for review in 2013/14. At this time Orion's load management master station will be over 10 years old and its adequacy will also need to be reviewed.

We expect that the result of these reviews will be a plan to develop a replacement system or systems for both existing master stations to be installed by 2015/16.

5.3.2 Coupling Cells and Controllers

These components are expected to have a life of at least 15 years and are not expected to be due for renewal for at least 10 years.

5.4 DISPOSAL PLAN

We plan to retire the 33kV ripple injection plants at Moffett and Hornby in 2017. This will provide spares for the remaining plants at Springston and Hororata.

5.5 CREATION / ACQUISITION PLAN

New 11kV ripple injection plants are installed in conjunction with new zone substations and conversions of existing 33kV zone substations to 66kV.

5.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.7 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.8 RISK ANALYSIS

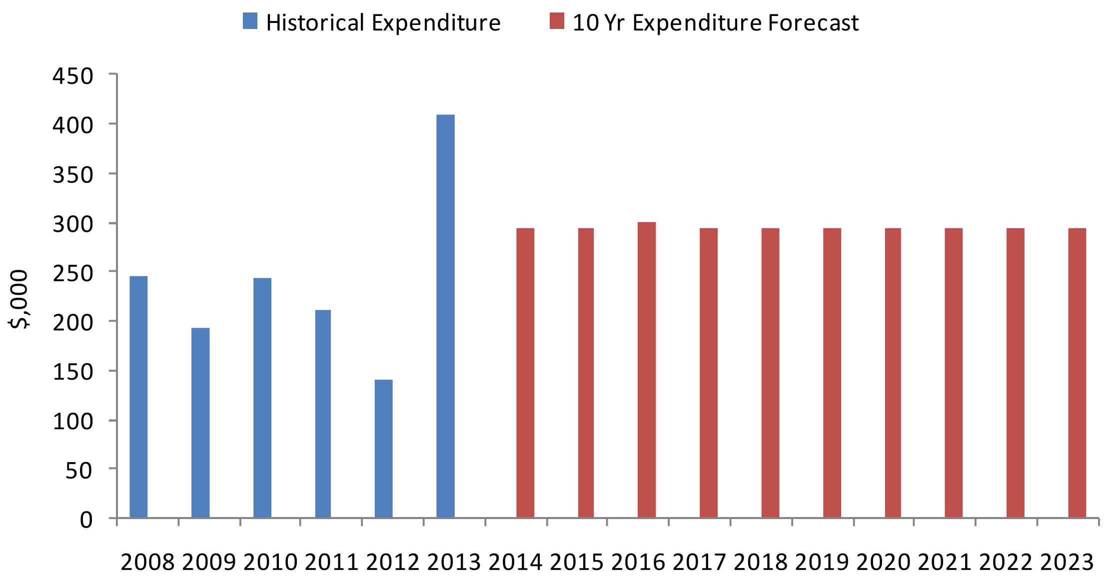
While the ripple plants themselves are in the early stages of their lifecycle, the master stations are either reaching or will have reached their end of life within the next couple of years. Hardware and software technical support for the master stations is becoming increasingly difficult to source and thus support systems have been put in place to mitigate the risk of failure. The functions these systems carry out are critical to Orion’s corporate objectives and as such a replacement programme has been planned as described above.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 3: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 4: Historical Load Management Systems Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	180	114	152	112	89	355
Non-Scheduled	51	65	79	80	21	35
Emergency	15	14	14	19	31	20
Total	**246**	**194**	**244**	**212**	**141**	**410**

Figure 5: Load Management Systems Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	230	230	230	230	230	230	230	230	230	230
Non-Scheduled	35	35	35	35	35	35	35	35	35	35
Emergency	30	30	35	30	30	30	30	30	30	30
Total	**295**	**295**	**300**	**295**	**295**	**295**	**295**	**295**	**295**	**295**

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 6: Historical and Forecast Expenditure

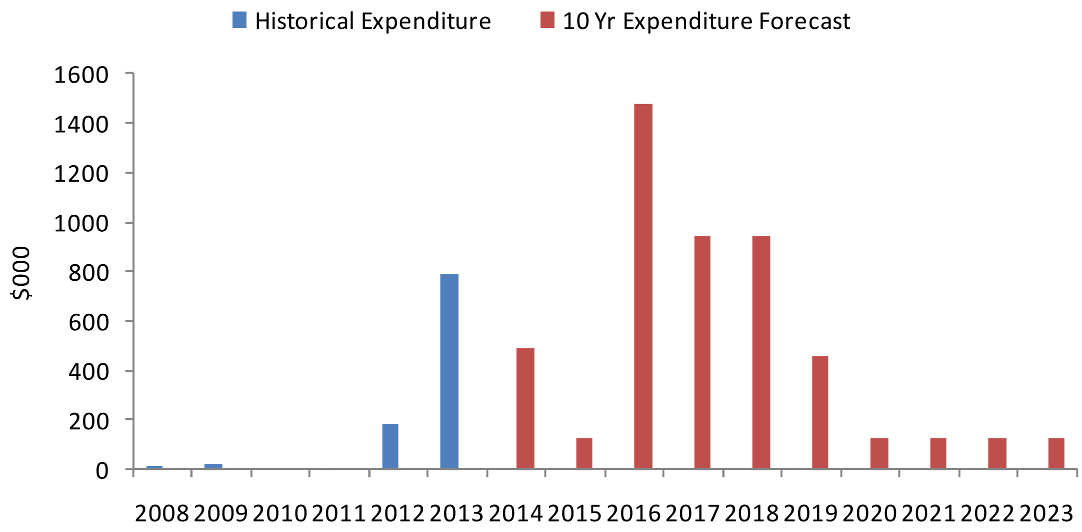


Figure 7: Historical Load Management Systems Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	11	23	0	7	181	790
Total	**11**	**23**	**0**	**7**	**181**	**790**

Figure 8: Load Management Systems Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	490	130	1480	940	940	460	130	130	130	130
Total	**490**	**130**	**1480**	**940**	**940**	**460**	**130**	**130**	**130**	**130**

Metering

Asset Management Report YE 2012

NW70.00.38

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1 INTRODUCTION

This document covers each of our metering categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these units.

2 ASSET DESCRIPTION

2.1 HIGH VOLTAGE (11KV) CONSUMER METERING

We own current transformers (CTs) and voltage transformers (VTs) used for metering, along with associated test blocks and wiring, at approximately 75 consumer sites. Retailers connect their meters to our test blocks. All Orion CTs and VTs are certified as required by the Electricity Governance Rules.

2.2 TRANSPOWER GRID EXIT POINT (GXP) METERING

We adopted GXP-based pricing in 1999, and most of our revenue is now derived from measurements by Transpower's GXP metering.

Orion also owns metering at 9 Transpower GXPs. We input the data from these meters into our SCADA system. Our measurements can also help the Reconciliation Manager to estimate data if Transpower’s meters fail, or are out of service.

Transpower has dedicated meters at all metering points. The GXPs at Arthur’s Pass and Castle Hill share CTs with our metering. With the Orion purchase of Papanui, the existing Transpower metering at Papanui has been left in place and will be moved back to Islington when the Papanui line breakers are replaced at Islington. All VTs are shared between Orion and Transpower. Although a truly credible check metering system would have stand-alone components with their own traceable accuracy standards, this is impractical.

2.3 POWER QUALITY MEASUREMENT METERING/MONITORING

Our power quality management in the past has been mainly reactive. We have responded to consumer complaints (which generally stem from the consumer's own actions) while assuming that the underlying network performance is satisfactory. We have not known the general underlying qualitative power quality performance of the network and whether it is deteriorating with time as an increasingly number of non linear loads are connected to the network. These non linear loads (which frequently reduce network power quality) are also perversely generally more sensitive to the very power quality issues they help to create.

We have installed power quality monitoring equipment at 31 sites throughout our network monitoring from 66 kV through to low voltage recording multiple power quality parameters which are archived to a on line database.

2.4 MAXIMUM DEMAND AMMETERS

We install maximum demand ammeters at all ground mounted distribution substations to monitor transformer loading. These meters are extremely rugged and have very long lives exceeding 40 years.

3 ASSET PERFORMANCE

We check that our metering figures support Transpower’s data. If the two sets of data differ significantly, meter tests may be required to establish where the discrepancy has occurred.

The two sets of data will never be identical – our GXP metering cannot definitively check Transpower's half-hourly metering values because:

- Some of our meters are in different locations from Transpower's meters
- Our meter-class accuracy differs from Transpower's
- The error correction factors that apply to Transpower's metering do not apply to us, as our metering uses different CTs
- In some locations we sum a number of metered values through auxiliary current summation transformers. As a result, our meters record more or less energy than Transpower's meters, which are all fitted with separate class 0.2 meters.

Our data however can be used to identify changing trends in the difference between the two metering systems, and to identify gross errors due to equipment failure.

4 ASSET CONDITION

4.1 GENERAL

GXP metering equipment has progressively been replaced from approximately 2000 onwards, generally in conjunction with Transpower metering replacement. New equipment has been installed when additional GXP's have been created.

Power quality metering equipment is less than 5 years old.

All metering equipment is in good condition.

4.2 HISTORICAL ISSUES

There have been a few failures of GXP and Power Quality meters but nothing beyond what would be typically expected from such electronic equipment.

5 ASSET MANAGEMENT PRACTICES

5.1 METERING LIFECYCLE

Our metering equipment at GXPs and power quality metering should be expected to have a minimum operational life of 15 years.

The Electricity Marketing rules require that our CTs and VTs must be recalibrated every 10 years. The CTs and VTs themselves should have an operational life of 45 to 50 years.

5.2 MAINTENANCE PLAN

We regularly inspect the metering sites, carry out appropriate calibration checks and witness the calibration checks on Transpower's metering.

Our meter testing contractors are required to have registered test house facilities which comply with the Electricity Governance Rules. They must also have documented evidence of up-to-date testing methods, and have competent staff to perform the work.

Our budgeted maintenance costs are shown in section 6.1 – Maintenance budgets/ meters.

5.3 REPLACEMENT PLAN

Most metering equipment is approximately at half life and thus a replacement plan is not required until beyond the end of the planning period.

5.4 DISPOSAL PLAN

We have no specific plans to dispose of any of this asset group.

5.5 CREATION / ACQUISITION PLAN

We have completed a three year project to install approximately 30 permanent standards compliant power quality measurement instruments across a representative cross section of distribution network sites which are expected to range from good (generally urban upper network) to poor (generally remote rural) power quality performance.

Additional instruments will be installed in the future where we connect new major customers and deem it necessary to provide them with an assurance of the level of power quality they are being supplied with.

These instruments will continue to collect power quality data, the analysis of which will provide a long term statistical view of typical network performance across a wide range of network conditions and locations. This data can also be used to provide a view of actual network power quality performance to assist with the development of standards and regulations.

Work is underway to trial an electronic replacement for maximum demand meters at distribution substations.

5.6 OUTCOMES

All of our maintenance and replacement programmes are developed to ensure the safety of the public and our personnel around our assets. We aim to strike a balance between cost and the quality of supply to our customers.

5.7 DELIVERABILITY

By having a smooth expenditure forecast we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

5.8 RISK ANALYSIS

CTs and VTs are extremely reliable standard components of high voltage switchgear and are maintained and replaced as part of our standard switchgear maintenance and replacement procedures.

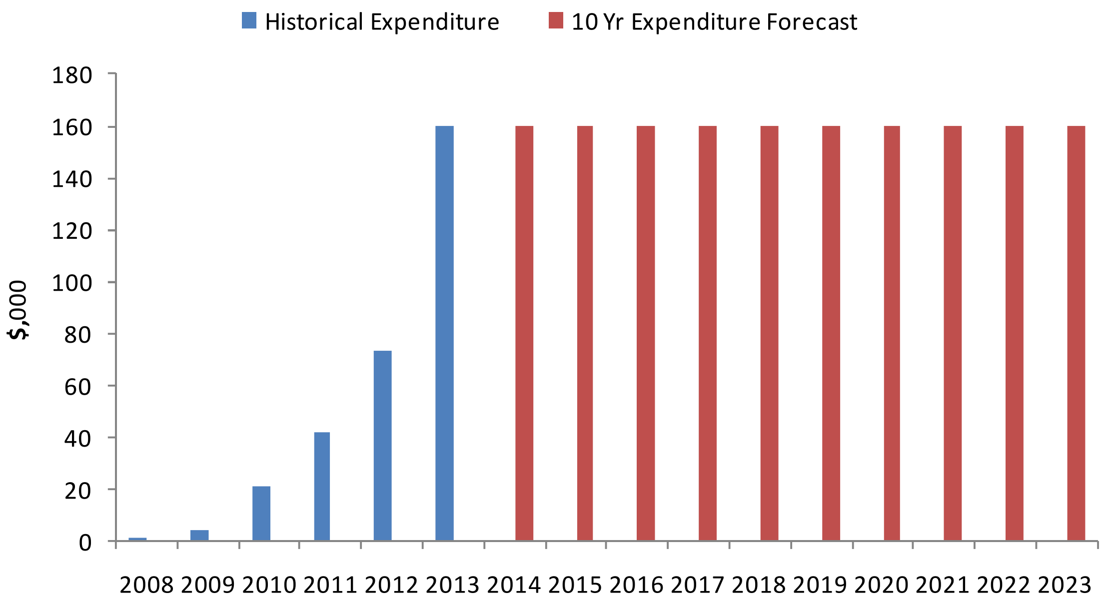
We hold sufficient spares to cover failures of CTs, VTs and other metering equipment.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 1: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as both our Orion and contractor resources were diverted to recovery and response works.

Figure 2: Historical Metering Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	0	4	21	27	73	155
Non-Scheduled	0	0	0	15	0	5
Emergency	0	0	0	0	0	0
Total	**1**	**4**	**21**	**42**	**73**	**160**

Figure 3: Metering Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	155	155	155	155	155	155	155	155	155	155
Non-Scheduled	5	5	5	5	5	5	5	5	5	5
Emergency	0	0	0	0	0	0	0	0	0	0
Total	**160**	**160**	**160**	**160**	**160**	**160**	**160**	**160**	**160**	**160**

6.2 REPLACEMENT EXPENDITURE

Our forward expenditure is a direct result of our replacement programme.

Figure 4: Historical and Forecast Expenditure

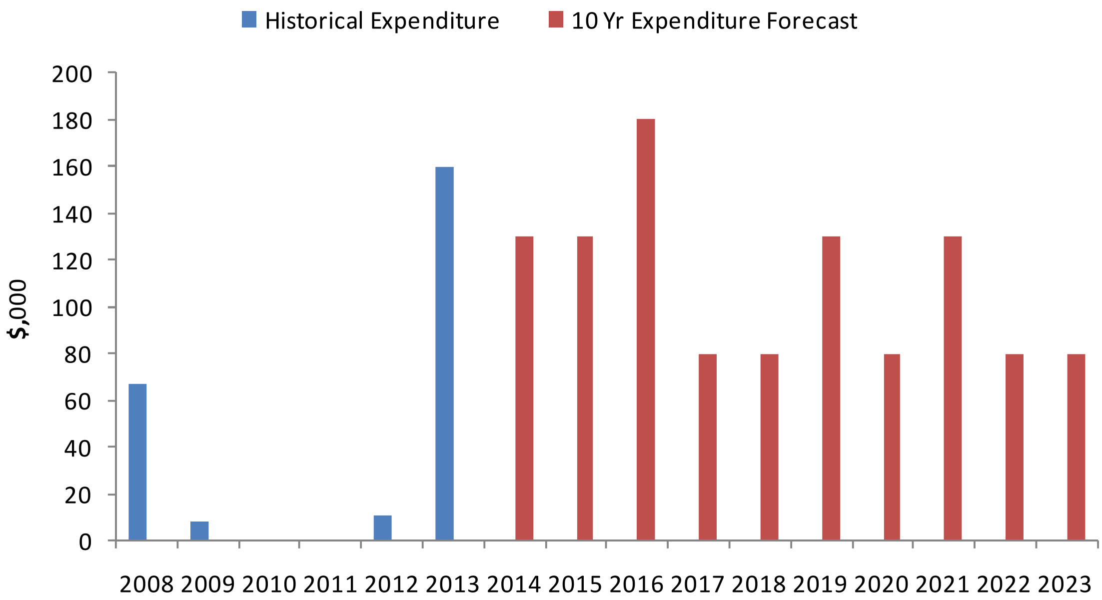


Figure 5: Historical Metering Replacement Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Replacement	67	8	0	0	11	160
Total	**67**	**8**	**0**	**0**	**11**	**160**

Figure 6: Metering Replacement Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Replacement	130	130	180	80	80	130	80	130	80	80
Total	**130**	**130**	**180**	**80**	**80**	**130**	**80**	**130**	**80**	**80**

Generators

Asset Management Report YE 2012



NW70.00.39

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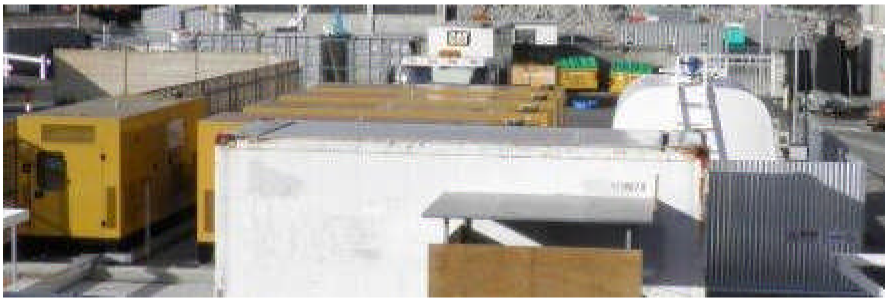
1 INTRODUCTION

Diesel generators provide a mobile source of energy to enable Orion to keep the power on or provide power quickly in the short term until the network is able to be restored. Orion has various generators which are used for different applications; mobile truck-based for use during planned works and faults, fixed for load lopping and mains failure and skid-mounted for isolated emergency response.

This document covers each of our generator categories and details the criteria and asset management practices used to ensure we obtain effective performance and acceptable service life from these generators.



2 ASSET DESCRIPTION

2.1 GENERAL

We have 18 medium to large diesel generators. Ten 550kVA generators can be strategically placed throughout our urban network. They are used for emergency backup and can be switched on-line in a short time frame if there is a loss of supply. Three of them have synchronisation gear fitted. Along with these generators we also have three truck-mounted units of 375, 400 and 440kVA (mobile) and one 110kVA trailer mounted generator, which are used to restore supply at a distribution level during a fault or planned work. The truck-mounted units are all fitted with synchronisation gear. We have a further 550kVA unit attached to our main office building with synchronisation gear and a 30kVA without synchronisation gear. Recently we have purchased two 2500kVA 11kV generators with synchronisation gear.

Figure 1: Orion's Generators

kVA	30	110	375	400	440	550	2500	Total
400V	1	1	1	1	1	11	-	16
11 kV	-	-	-	-	-	-	2	2

2.1.1 Summary of Generators > 30 kVA

Asset No.	Type	Make	Model	Year	Voltage	kW Stby	kVA Stby	Location
G1	Building	Cat	GEP550-2	2010	400	440	550	ARM B
G2	Islanded	Cat	GEP550-2	2009	400	440	550	ARM Y
G3	Islanded	Cat	GEP550-2	2009	400	440	550	ARM Y
G4	Islanded	Cat	GEP550-2	2010	400	440	550	ARM Y
G5	Islanded	Cat	GEP550-2	2010	400	440	550	ARM Y
G6	Building	Cat	GEP550-2	2011	400	440	550	ARM Y
G7	Islanded	Volvo	V550C2	2011	400	440	550	TD HOR
G8	Islanded	Volvo	V550C2	2011	400	440	550	TD HOR
G9	Sync	Volvo	V550C2	2011	400	440	550	TD HOR
G10	Islanded	Volvo	V550C2	2011	400	440	550	TD HOR
G11	Sync	Volvo	V550C2	2011	400	440	550	TD HOR
G17	Sync	Cat	3516B-HD	2012	11000	2000	2500	QEII
G18	Sync	Cat	3516B-HD	2012	11000	2000	2500	QEII
G20	Hotsite	Cat	GEP30	2004	400	24	30	ARM S
G21	Trailer	FG Wilson	P110E	1997	400	88	110	ARM Y
V751	Truck	FG Wilson	P375E	1995	400	300	375	ARM Y
V755	Truck	FG Wilson	P440E	2005	400	352	440	ARM Y
V760	Truck	Cat	Cat 3406	2009	400	320	400	ARM Y
				18		9924	12405	

2.1.2 Summary of Diesel Tanks

Asset No.	Model	Year	Safe Fill Level	Location
TK001	iT15	2011	16155	200 Armagh
TK002	EBD100	2012	*10000*	QEII
TK003	30TCG	2010	2900	QEII
TK004	30TCG	2010	2900	QEII
TK005	30TCG	2012	2900	QEII

2.2 G17 & G18 - 11KV GENERATORS

Figure 2: 11kV Generator Details

Generator Details	
Model	XQ2500
Make	Cat
Location	QE11
Quantity	2
Voltage	11000
KW	2000
kVA	2500
Sync	Yes
Comms	Ethernet
Weight	36,000
Tank	4400
Revenue Meter	Yes

Presently these generators are located at QEII. In 2016 they will most likely be moved to Belfast. The generators primary purpose is to boost the 11kV network under N-2 conditions. They are also used for peak lopping. They can also be islanded.

The generators have engine control units with electronic injectors but are not classed as common-rail. The fuel rail is low pressure with the pressure rising in the injector. The generators have digital AVR’s (CDVR) and Woodward EasYgen 3200 P1 digital touch screen controllers. These have a Proconx Ethernet interfaced through CAN1.

Both generators are fitted with a Foxboro RTU and revenue meters.

While at QEII the generators will be used for:

- Peak lopping network load
- Emergency 11kV N-2 support from McFaddens or Papanui
- High electricity prices.

Operator Instruction NW72.13.113.

2.3 400V SKID MOUNT GENERATORS

All the 550kVA generators are low emission and have an electronic common rail fuel system.

GEP550-2

2.3.1 G02, G03, G04, G05 - Cat GEP550-2 - 400V Emergency Standby

Presently these generators are located at 200 Armagh St.

Figure 3: 400V Emergency Standby Generator Details

Generator Details	
Model	GEP550-2
Location	Armagh
Quantity	4
Voltage	400
KW	440
kVA	550
Sync	No
Comms	No
Revenue Meter	No

2.3.2 G01 & G06 - Cat GEP550-2 –400V Building Generators with Synchronisation

Presently these generators are located at 200 Armagh St. It is planned to leave G06 connected to the Armagh St Building and install G01 at Wairakei Rd once it has been repaired. Prior to the construction of a new office building at Wairakei Rd G06 was to go to Arthur's Pass. A SDMO generator G07 may go to Arthur's Pass instead.

Figure 4: Armagh Street Standby Generator Details

Generator Details	
Model	GEP550-2
Location	Armagh
Quantity	2
Voltage	400
KW	440
kVA	550
Sync	Yes
Comms	TBA
Weight	5590
Tank	900
Revenue Meter	Via building

2.3.3 G07, G08, G10 - SDMO V550C2 – 400V Emergency Standby

Presently these generators are located at Halswell Junction Rd in Hornby.

Figure 5: Emergency Standby Generator Details

Generator Details	
Model	V550C2
Location	TD HOR
Quantity	3
Voltage	400
KW	440
kVA	550
Sync	No
Comms	No
Weight	5500
Tank	1790
Revenue Meter	No

2.3.4 G09 & G11 - SDMO V550C2 –- 400V Emergency Standby & Synchronisation

Presently these generators are located at Halswell Junction Rd in Hornby. In the future these two generators will be located at Castle Hill.

Figure 6: Emergency Standby Generator Details

Generator Details	
Model	V550C2
Location	TD HOR
Quantity	2
Voltage	400
KW	440
kVA	550
Sync	Yes
Comms	No
Weight	5500
Tank	1790
Revenue Meter	No

2.3.5 G20 - CAT GEP30 – 400V Emergency Standby

This generator is located at 200 Armagh St and provides an auto mains failure changeover supply for our Hot-site. In turn the Hot-site UPS provides a supply for the Hot-site servers, one computer in the control room and one computer in the call centre.

Figure 7: Armagh Zone Substation Standby Generator Details

Generator Details	
Model	GEP
Location	ARM SUB
Quantity	1
Voltage	400
KW	27
kVA	30
Sync	No
Comms	No
Weight	800
Tank	145
Revenue Meter	No
75%	25 hrs

2.4 MOBILE GENERATORS

The trucks can each be synchronised to the network and are fitted with revenue meters.

V751

V755

V760

2.4.1 Mobile Generator - V751 350 kVA

Figure 8: Generator Truck V751 Details

Generator Details	
Model	350
Location	ARM
Quantity	1
Voltage	400
KW	280
kVA	375
Sync	Yes
Comms	Cell-modem
Tank	600
Revenue Meter	Yes

V751 has a truck mounted generator with a Comap Intelligen controller. The setup allows the generator to be:

- Synchronised to the network
- Auto kW voltage support with auto stop/start
- Reverse sync over LV fuses
- Islanded operation
- Network isolator switch
- Ability to be islanded with other like controllers
- Monitoring via a DNP3 micro RTU connected to the Comap Intelligen
- Communications via a cellular modem

Operator Instruction Nw72.13.97.

2.4.2 Mobile Generator - V755 440 kVA

Figure 9: Generator Truck V755 Details

Generator Details	
Model	P440E
Location	ARM
Quantity	1
Voltage	400
KW	352
kVA	440
Sync	Yes
Comms	Cell-modem
Tank	782
Revenue Meter	Yes

V755 has a truck mounted generator with a basic FG Wilson 4000 controller. The setup allows the generator to be:

- Synchronised to the network manually using synchroscope
- Islanded operation
- Manual kW and pF operation
- GCB & MCB circuit breakers
- HV trip input circuit from a 11kV earthing transformer
- Remote fuel tank dry break coupling and valves
- Electronic engine
- Monitoring via a DNP3 micro RTU connected to 3ph industrial meter and hardwired inputs
- Communications via a cellular modem
- It is proposed to fit a new controller in the future to automate the generator operation.

Operator Instruction NW72.13.98.

2.4.3 Mobile Generator - V760 400 kVA

Figure 10: Generator Truck V760 Details

Generator Details	
Model	C3406
Location	ARM
Quantity	1
Voltage	400
KW	320
kVA	400
Sync	Yes
Comms	Cell-modem
Tank	1900
Revenue Meter	Yes

V760 has a truck mounted generator with a Woodward EasYgen 3200 controller. The setup allows the generator to be:

- Synchronised to the network
- Islanded operation
- Ability to be islanded with other like controllers
- Large 1900 litre diesel tank
- Monitoring via dnp3 Foxboro RTU connected to the Woodward EasYgen
- Communications via a cellular modem

Operator instruction NW72.13.109.

2.4.4 G21 - Trailer Mounted 110kVA

Figure 11: Trailer Generator G21 Details

Generator Details	
Model	P110E
Location	ARM
Quantity	1
Voltage	400
KW	88
kVA	110
Sync	No
Comms	No
Weight	2000
Tank	490
Revenue Meter	No

The 110kVA was the Armagh St Building generator. It has been trailer mounted to allow it to be used for smaller jobs that would otherwise tie up a truck for extended periods. In the future this may be installed with synchronisation gear to allow it to be used for voltage support jobs.

The generator has a basic FG Wilson control panel. The setup allows the generator to be:

- Towed by an operator's utility vehicle
- Islanded operation. Cannot be synchronised.
- GCB circuit breaker
- Mains Isolator
- Mechanical engine and governor
- Communications via a cellular modem
- It is proposed to fit a new controller in the future to automate the generator operation and allow synchronisation.

2.5 DIESEL TANKS

Orion has five diesel tanks and a mobile trailer tank. A sixth may be purchased.




TK01 - iTank15 | TK02 - EBD10 | TK03 - 30TCG | Trailer

2.5.1 Armagh St Tank – TK01 – iTank15 16,200 Litre

Figure 12: Tank TK01 Details

Tank Details	
Model	iTank15
Make	Advanced Fuel Tanks
Group	Vanguard
Type	Double skinned
Location	ARM
Supplier	Advanced Tanks, Bromley
Quantity	1
Litres	16,200

The Armagh St tank was purchase to provide an emergency reserve supply for the operator vehicle fleet and building generator should the Christchurch supply lines become disrupted for up to three days. As such the idea was to maintain a reserve of 8000 litres and take delivery of 7000 litres at a time.

Manufacturer & supplier: Advanced fuel tanks, Bromley.

TK01 is fitted with:

- A remote electronic fuel dispenser
- 1 x 38mm outlet with 24Vdc solenoid valves
- 1 x 38mm inlet (return)
- x 4-20mA level transducer and display

2.5.2 QEII Tank – TK02 – EBD10 10,000 Litre

Figure 13: Tank TK02 Details

Tank Details	
Model	EBD10
Make	Western Environmental
Group	EnviroBulka Deluxe
Type	Bunded
Location	ARM
Supplier	Civilquip, Greymouth
Quantity	1
Litres	10,000

It was decided that the QEII generators should be able to run for more than 24 hrs before needing to be refuelled. Each generator has a 4400L day tank and bulk tank/tanks to support it. Presently G18 is connected to it.

TK002 also has:

- An emergency electronic fuel dispenser for Orion operator vehicles and generator trucks including a 6m hose reel.
- 25mm outlets with 24VDC solenoid valves
- 1 x 25mm inlet
- 1 x 4-20mA level transducer
- Overfill sounder

2.5.3 QEII Mobile Tanks – TK03, 04, 05 – 30TCG 2,900 Litre

Figure 14: QE11 Mobile Tank Details

Tank Details	
Model	30TCG
Make	Western Environmental
Group	Envirocube
Type	Bunded
Location	QE11
Supplier	Civilquip, Greymouth
Quantity	3
Litres	2,900

Orion has three 30TCG enclosed bunded tanks at QEII. The TCG30 includes baffles and can be moved full of diesel unlike most diesel tanks. If one of the XQ2500 generators or V755 moves to a remote location, one or more of TCG tanks can follow. G17 is presently connected to it.

Each tank has:

- 1 x 25mm outlet with 24Vdc solenoid valve
- 1 x return
- 1 x additional suction outlet.

- Level gauge with resistive sender
- Overfill sounder

2.5.4 Wairakei Road Tank – TK06 – 4,500 Litre

Figure 15: Tank TK06 Details

Tank Details	
Model	50TCG Cab
Make	Western Environmental
Group	Envirocube
Type	Bunded
Location	Wairakei
Supplier	Civilquip, Greymouth
Quantity	1
Litres	4,500

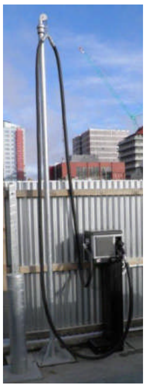
Wairakei Rd has a need for a 4,500 litre tank to ensure the generator is able to run at 400A (275kW) for three days.

2.5.5 Trailer Tank – 1500 Litre

The mobile trailer tank is stored in the yard at 200 Armagh St. It is fitted with a 12VDC diesel pump and is able to hold 1500 litres of diesel.

2.5.6 Fuel Dispensers

Orion has 2 fuel dispensers (bowsers). One is external to the bulk tank at Armagh St and the other is locked inside the bulk tank at QEII. QEII is only for emergency use. Both are Piusi Cube 70 MC, AC powered, 70 litres per minute with auto cut-off nozzles. They store each diesel transaction and require an electronic key to activate. Both units use the same set of keys.



Armagh Yard

QEII Bulk Tank – TK02

Refer to Environmental Management Procedures for Oil and Fuel NW70.10.02.

2.5.7 Spill Kits

There is a Spill kit in the Armagh Yard over the other side of the fence at the end of the Bulk tank TK01 and another at QEII inside the door to the right of bulk tank TK02.

3 ASSET PERFORMANCE

All generators are operated within their nameplate ratings. Operating the generators at their standby ratings shortens their life. However as Orion will operate the generators for less than 500 hours per year and in a normal year less than 100 hours, operating them hard will not result in the generators lasting for less than 20 years plus.

A number of our generators were used to supply electricity to the worst affected areas in the eastern suburbs immediately after the February 2011 earthquake. These units were run continuously until our network was repaired. The load on the generators was kept below 75% of the Standby rating because of the continuous operation. During this time they performed well.

None of the generators had any mechanical faults during this time.

4 ASSET CONDITION

4.1 GENERAL

All generators are checked, tested and maintained in good operational condition.

Most of our generator fleet is relatively new. Because they need to be ready for emergency use they are tested and maintained on a regular basis. As a result all of our generators are in good operational condition.

4.2 DIESEL TANKS

All the diesel tanks are new and are bunded or double skinned. They are all in good condition.

4.3 HISTORICAL ISSUES

The generators are rotating machines that are subject to vibration, heat and dust while running and while in transit. As a result the generators require regular maintenance and tuning to ensure that stay in an optimal state.

G21 P110E – Stator has been rewound

V751 P375E – Stator removed, cleaned, vanished and reinstated

V755 Shutdown due to overheating. Liquefaction cleaned from Radiator

The generators have frequent minor issues that require minor tuning and these are taken care of by Orion staff.

5 ASSET MANAGEMENT PRACTICES

5.1 GENERAL

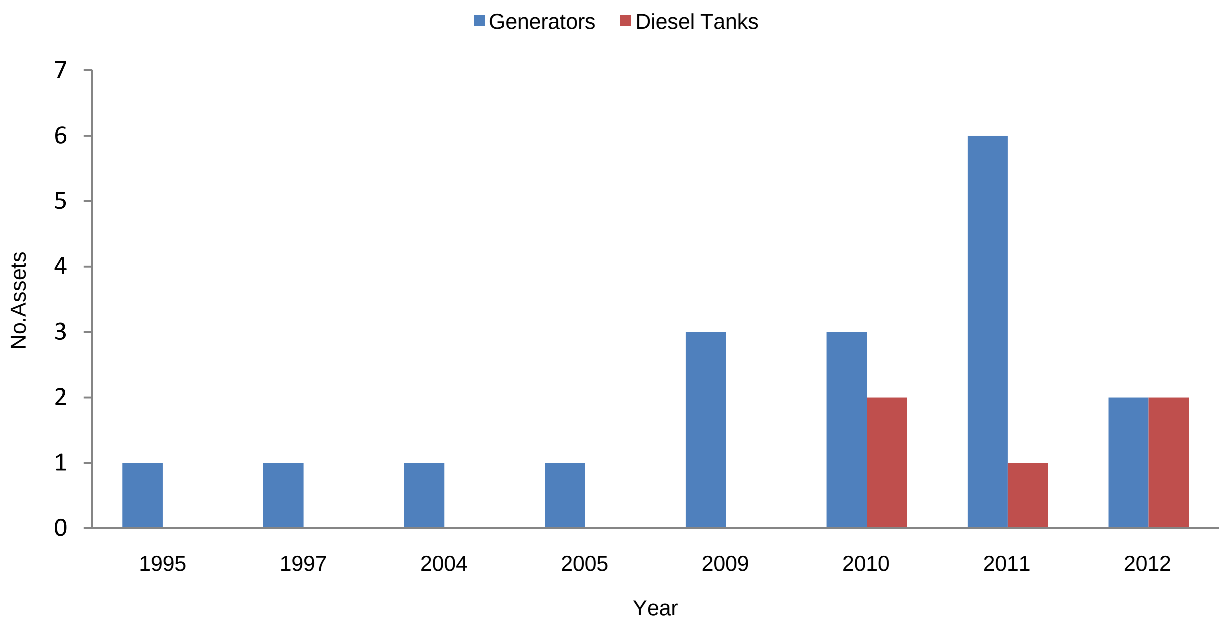
We employ a number of different asset management practices for different generator groups. The different types of generators and ages require different schedules to best suit each machine.

5.2 GENERATOR LIFECYCLE

5.2.1 Generators

Generators will be sold when it becomes clear that they are no longer economic to keep. In general the generators have low and varied running hours per year. The first medium service interval is about 3000 hours and the first major overhaul will occur between 30,000 and 50,000 hours. It is envisaged that the large generators will normally run for 100 hours per year, 3000 hours in 30 years and the Trucks maybe twice this amount. Dry-year generation may affect it, but it is unknown if dry-year generation might occur. A few of the generators ran for over 1000 hours during the February 2011 earthquake.

Figure 16: Age Profile - Generators



5.3 MAINTENANCE PLAN

5.3.1 General

We contract several providers to service our generators. Employees and contractors regularly inspect and test each generator. The maintenance practices are a mixture of time and condition based. From time to time individual components that are shown to become unreliable will also be replaced. All generators have hour meters and the generators that are used regularly have recently been fitted with remote monitoring. Monitoring assists in highlighting pending issues as well as diagnosing faults quickly.

Maintenance includes:

- inspection before use
- monthly testing
- service checks every six months
- yearly oil and coolant samples will be taken on the large generators
- yearly fuel samples will be taken on generators with low use
- XQ2500's, V550C2's and GEP550-2 fully serviced at 500 hour intervals
- mobile trucks and trailer serviced at 250 hour intervals
- oil and coolant change every 3 years unless a drop in quality is indicated by the samples or the service interval is reached
- the block heaters and space heaters are kept warm
- test run once a month and put on a load bank once a year.
- our budgeted maintenance costs are shown in Appendix A – Maintenance budgets/ Generators (fixed).

5.3.2 G17 & G18 – XQ2500

To be contracted to Goughs for the warranty period of five years.

Refer to Appendix A.

5.3.3 G02, G03, G04, G05 – GEP550-2

Maintenance is contracted to Goughs for the warranty period of two years. Orion keeps the generators in a ready to run state.

5.3.4 G01 & G06 – GEP550-2

Maintenance is contracted to Goughs for the warranty period of two years. Orion synchronises and runs the generators on load once a month.

5.3.5 G07 to G11 – V550C2

These units are maintained by Transdiesel in a ready state.

Oil changes are carried out every 500 hours.

5.3.6 V751, V755, V760, G20 and G21

The truck generators are maintained by Total Power Solutions - TPS.

It general the generators have an oil change every 250 hours. The generators exceed these hours every year.

5.3.7 Diesel Fuel

Orion plans to cycle all diesel fuel over within 12 months to keep it in good condition. It is also planned to sample all diesel once a year in generators and tanks except for the mobile trucks which turn over enough diesel to forgo the tests.

Diesel is best stored in a tank where moisture can't get in. Keeping a tank completely full or completely empty assists in reducing condensation.

At QEII it is planned to generator for 100 hours every year. The generators will use 50,000L of diesel each (total 100,000L) and cycle each tank five times during the winter season.

At the Orion main office building the main generator will have 4500L of diesel storage beside it to allow for three days running. Unless an event occurs the generator will only run for one hour once a month consuming 810 litres for the year (270kW). Therefore it is proposed to empty the tank TK06 once a year and move the fuel to either QEII to TK02 or into the Armagh St bulk fuel tank TK01. It is assumed the Armagh St bulk fuel tank TK01 will go Papanui. In turn it is proposed to fill the Generator Trucks from the Armagh St tank TK01 to ensure its fuel gets turned over.

5.4 REPLACEMENT PLAN

There is no renewal plan for the generator fleet. When a generator gets to the end of its economic life an analysis will be done to see if it will be replaced.

The mobile truck generators will be replaced when it becomes clear they are uneconomic to keep operating. This will depend on the type of fault, and the number of hours the generator performs every year. Fault type and number of hours may vary greatly from year to year.

It is planned to replace Mobile Truck V751 in 2016 with a new truck and using one of the existing GEP550-2 generators.

Various individual components will be upgraded on different mobile generators each year to ensure they have a high availability.

5.5 DISPOSAL PLAN

These assets are disposed of by auction when they become surplus to our requirements or they become uneconomic to continue to operate. As seismic activity lessens, the level of risk to the network will reduce. Therefore we will continue to review our needs for the generator fleet.

5.6 CREATION / ACQUISITION PLAN

We have resource consents to install 11.5MW of diesel generating capacity at both Bromley and Belfast (23MW in total). Proceeding with either of these sites is subject to a viable business case being developed. Belfast is the most likely in 2016.

The earthquake damage to our network in the eastern suburbs has caused us to temporarily locate and consent 4 MW of transportable generation at QEII Park for the next several years commencing April 2012. This generation may in the future be relocated to our Belfast site to cope with increased peak loads as new housing develops in that area.

5.7 OUTCOMES

Prior to the Canterbury earthquakes, our generator requirements were limited. We have increased our numbers as a direct result of the earthquakes to ensure we are in a position to restore power in a timely fashion after an event.

5.8 DELIVERABILITY

We have supply contracts and agreements in place to ensure there is sufficient diesel for the generators after an event.

5.9 RISK ANALYSIS

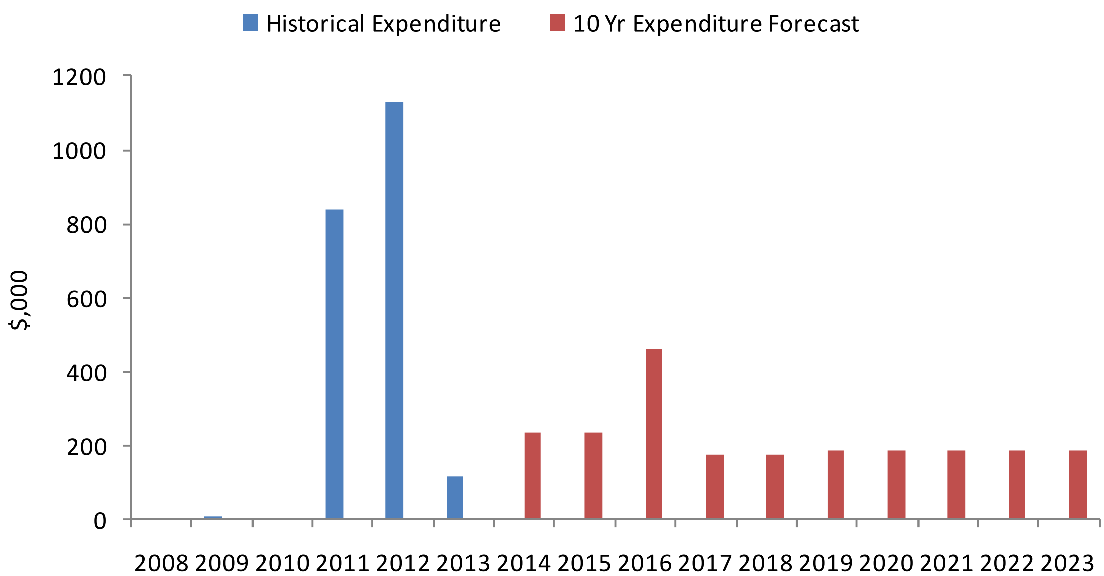
They are no faults with any of the generators at present that required them to be operated in a reduced power state.

6 EXPENDITURE

6.1 MAINTENANCE EXPENDITURE

Our expenditure is based on maintaining our current levels of safety and reliability.

Figure 17: Historical and Forecast Expenditure



The Canterbury earthquakes had an effect on our maintenance expenditure in 2011 and 2012 as we rapidly increased our generator numbers.

Figure 18: Historical Generator Maintenance Expenditure ($,000)

FYE	2008	2009	2010	2011	2012	2013
Scheduled	5	7	0	0	323	100
Non-Scheduled	0	0	0	0	0	10
Emergency	0	0	2	841	807	5
Total	**5**	**7**	**2**	**841**	**1130**	**115**

At the time of writing the budgeted rather than actual expenditure figures for 2013 were used.

Figure 19: Generator Maintenance Expenditure Forecast ($,000)

FYE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scheduled	220	220	440	160	160	170	170	170	170	170
Non-Scheduled	10	10	10	10	10	10	10	10	10	10
Emergency	5	5	10	5	5	5	5	5	5	5
Total	**235**	**235**	**460**	**175**	**175**	**185**	**185**	**185**	**185**	**185**

Our scheduled maintenance for our generator fleet has increased due to the number of new units we have as a direct response to the Canterbury earthquakes. These units are maintained as part of a service agreement with the suppliers.

Our non-scheduled maintenance forecast is used for unknown issues that may occur but would not be carried out under the emergency contract.

The emergency works contract now contains new resiliency criteria that require our contractors to meet our obligations under the Civil Defence Emergency Management CDEM Act. A risk review was undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of the asset classes.

6.2 REPLACEMENT EXPENDITURE

At this stage there is no replacement programme for our generators. As units reach the end of economic life they will be sold off or disposed of.

Appendix A

G17 & G18 Maintenance Plan

Product: GENERATOR SET
Model: 3516B GENERATOR SET ZAR
Configuration: 3516B Generator Set ZAR00001-UP
Operation and Maintenance Manual
3500 Generator Sets
Media Number -SEBU7789-06 Publication Date -01/08/2011 Date Updated -08/08/2011
i04500469
Maintenance Interval Schedule - Standby
SMCS - 1000; 4450; 7500
Ensure that all safety information, warnings and instructions are read and understood before any operation or any maintenance procedures are performed.
An authorized operator may perform the maintenance items with daily intervals. An authorized operator may perform the maintenance items with intervals of every week. The maintenance that is recommended for all other maintenance intervals must be performed by an authorized service technician or by your Caterpillar dealer.
The user is responsible for the performance of all maintenance which includes the following items: performing all adjustments, using proper lubricants, fluids, and filters and replacing old components with new components due to normal wear and aging.
Failure to adhere to proper maintenance intervals and procedures may result in diminished performance of the product and/or accelerated wear of components.
Before each consecutive interval is performed, all maintenance from the previous intervals must be performed. Choose the interval that occurs first in order to determine the correct maintenance interval: fuel consumption, service hours and calendar time. Products that operate in severe operating conditions may require more frequent maintenance.
All of the following will affect the oil change interval: operating conditions, fuel type, oil type and size of the oil sump. Scheduled oil sampling analyzes used oil in order to determine if the oil change interval is suitable for your specific engine.
Refer to this Operation and Maintenance Manual, "Engine Oil and Filter - Change" in order to determine the oil change interval that is suitable for your specific engine.
To determine the maintenance intervals for the overhauls, refer to this Operation and Maintenance Manual, "Maintenance Recommendations" .
Unless other instructions are provided, perform maintenance and perform repairs under the following conditions:

- The starting system is disabled.
- The engine is stopped.
- The generator does not pose an electrical shock hazard.
- The generator is disconnected from the load.

When Required

- Battery - Recycle
- Battery or Battery Cable - Disconnect
- Fuel System - Prime
- Fuel System Primary Filter/Water Separator - Drain
- Generator - Dry
- Generator Bearing - Lubricate
- Generator Set - Test
- Generator Set Alignment - Check
- Generator Winding - Test
- Varistor - Test
- Zinc Rods - Inspect/Replace

Every Week

- Air Inlet Filter - Check
- Air Starting Motor Lubricator Oil Level - Check
- Air Tank Moisture and Sediment - Drain

- Annunciator Panel - Inspect
- Automatic Start/Stop - Inspect
- Battery Charger - Check
- Battery Electrolyte Level - Check
- Cooling System Coolant Level - Check
- Electrical Connections - Check
- Engine Air Cleaner Service Indicator - Inspect
- Engine Air Precleaner - Clean
- Engine Oil Level - Check
- Fuel Tank Water and Sediment - Drain
- Generator - Inspect
- Generator Bearing Temperature - Test/Record
- Generator Lead - Check
- Generator Load - Check
- Jacket Water Heater - Check
- Power Factor - Check
- Space Heater - Check
- Standby Generator Set Maintenance Recommendations
- Stator Winding Temperature - Test
- Voltage and Frequency - Check
- Walk-Around Inspection

Every 50 Service Hours

- Zinc Rods - Inspect/Replace

Every 6 Months

- Cooling System Coolant Sample (Level 1) - Obtain

Every Year

- Air Shutoff - Test
- Air Starting Motor Lubricator Bowl - Clean
- Alternator - Inspect
- Belts - Inspect/Adjust/Replace
- Cooling System Coolant Sample (Level 2) - Obtain
- Cooling System Supplemental Coolant Additive (SCA) - Test/Add
- Crankshaft Vibration Damper - Inspect
- Engine - Clean
- Engine Air Cleaner Element (Dual Element) - Clean/Replace
- Engine Air Cleaner Element (Single Element) - Clean/Replace
- Engine Crankcase Breather - Clean
- Engine Mounts - Check
- Engine Oil Sample - Obtain
- Engine Oil and Filter - Change
- Engine Protective Devices - Check
- Engine Valve Lash - Inspect/Adjust
- Fan Drive Bearing - Lubricate
- Fuel Injector - Inspect/Adjust
- Fuel System Primary Filter (Water Separator) Element - Replace
- Fuel System Secondary Filter - Replace
- Generator Set Vibration - Test/Record
- Generator Winding Insulation - Test
- Hoses and Clamps - Inspect/Replace
- Prelube Pump - Inspect
- Radiator - Clean
- Rotating Rectifier - Check
- Rotating Rectifier - Inspect/Test
- Speed Sensor - Clean/Inspect
- Starting Motor - Inspect
- Stator Lead - Check
- Varistor - Inspect

- Water Pump - Inspect

Every 3 Years

- Air Shutoff Damper - Remove/Check
- Batteries - Replace
- Cooling System Coolant (DEAC) - Change
- Cooling System Coolant Extender (ELC) - Add
- Cooling System Water Temperature Regulator - Replace
- Turbocharger - Inspect

Every 6 Years

- Cooling System Coolant (ELC) - Change

Commissioning

- Generator Set Alignment - Check
- Generator Set Vibration - Test/Record

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