Aurora ENERGY

ABN 85 082 464 622

MANAGEMENT PLAN 2011

GROUND MOUNTED SUBSTATIONS

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0	18 Feb 2011	Original Issue. (NW-#30160765-V4A). Based on Asset Management Plan 2007 (NW10218717)	Prepared by	FP
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			Approved by	AD
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			Reviewed by	ST
			Approved by	AD

1. PURPOSE

The purpose of this document is to describe for Ground Mounted Substations and related assets:

- Aurora's approach to asset management, as reflected through its legislative and regulatory obligations and Network Management Strategy;
- The key projects and programs underpinning its activities for the period 2012/2013 – 2016/2017; and
- Forecast CAPEX and OPEX, including the basis upon which these forecasts are derived.

2. STRATEGY

The objective of the Network Management Strategy is:

To minimise cost of supply to the customer whilst:

1. *Maintaining network performance;*
2. *Managing business operating risks; and*
3. *Complying with regulatory, contractual and legal responsibilities.*

3. SCOPE

This document covers high voltage (HV) and low voltage (LV) switchgear, ground mounted distribution transformers and their associated enclosures and earthing systems.

The management of zone substations is covered by the Management Plan 2011: Zone Substations (reference 1).

The management of HV Regulators is covered by the Management Plan 2011: High Voltage Regulators (reference 2).

The management of pole mounted substations is covered by the Management Plan 2011: Overhead System and Structures (reference 3).

4. DESCRIPTION OF THE ASSETS

A distribution substation may be for the switching of HV distribution feeders only (also known as a switching station) or for the switching and transforming the HV of the distribution feeder to the secondary system voltage (400/230 V).

Distribution substations are divided into ground mounted substations and pole mounted substations.

Ground mounted substations generally supply large loads or a large number of customers predominantly within underground reticulations. They are

generally considered permanent installations and are not easily upgraded or relocated once established.

Ground mounted substations can be further divided into the following types based on enclosure:

1. **Building:** Indoor equipment enclosed in a permanent building with working space and passageways;
2. **Fence:** Predominantly outdoor equipment, but may be indoor equipment installed in individual weatherproof housings, within a fenced enclosure;
3. **Kiosk:** Indoor equipment enclosed in a common weatherproof housing with little or no working space or passageway. Provision is made for individual items to be changed;
4. **Padmounted:** A complete assembly, which is installed or replaced as a unit on a concrete foundation at ground level; and
5. **Vault:** Indoor equipment housed in an underground vault with access by a vertical hatchway from a road or footpath.

Table 1 details the number of each type of ground mounted substation installed in the system as at August 2010.

Table 1: Ground Mounted Substation types installed in Aurora's distribution system as at August 2010

Type	Voltage	Number Installed
Building	11	278
	22	115
Fence	11	120
	22	71
Padmount/Kiosk	11	731
	22	515
Vault	11	3
	22	0
Total		**1833**

The transformers installed in ground mounted substations transform the HV of the distribution feeder to the secondary system voltage (400/230 V). Ground mounted substations have one to two transformers ranging in size from 500 kVA to 1500 kVA. There are a small number of older transformers in the system of non-standard sizes. On replacement these units will be replaced with a standard transformer size. The number and size of units is dependent on the load or customer requirements at a particular point within the distribution system. Table 2 details the number of transformers installed in the system by size and voltage.

Table 2: Ground mounted distribution transformers installed in Aurora's distribution system as at August 2010

Size (kVA)	Voltage (kV)	Number Installed
500	11	670
	22	306
750	11	269
	22	248
1000	11	55
	22	39
1500 or greater	11	112
	22	109
Total		**1808**

The switchgear installed in ground mounted substations primarily provides isolation, disconnection and connection points when carrying out operational switching within the HV (11 kV and 22 kV) and LV (230/400 V) networks.

There is a variety of HV switchgear types, makes and ages installed in the distribution network. It may be air-, gas- or oil-insulated, have either single- or three-phase operation and may be of either an indoor or an outdoor type. Table 3 details the types of HV switchgear installed in the system.

Table 3: High voltage switchgear installed in Aurora's distribution system as at August 2010

Description	Insulation Type	Voltage	Number Installed
Asea Brown Boveri RGB 12	Air or Gas	11 kV	512
Asea Brown Boveri RGB 24	Air or Gas	22KV	39
Asea Brown Boveri CTC24	Air or Gas	11 kV and 22 kV	75
English Electric OLX	Oil	11 kV	38
Fluokit	Air or Gas	11 kV and 22 kV	134
GEC	Oil	11 kV and 22 kV	13
Hazemeyer	Air or Gas	11 kV	97
Merlin Gerin	Air or Gas	11 kV and 22 kV	175
Merlin Gerin M6	Air or Gas	11 kV and 22 kV	106
Merlin Gerin RM6	Air or Gas	11 kV and 22 kV	152
Merlin Gerin SM6	Air or Gas	11 kV and 22 kV	21

Description	Insulation Type	Voltage	Number Installed
Reyrolle JKSS	Oil	11 kV	105
Reyrolle LMT	Oil	11 kV	105
Siemens	Air or Gas	22 kV	24
Yorkshire	Air or Gas	11 kV	3
Statter	Oil	11 kV	39
Spreicher	Oil	22 kV	2
Brush	Oil	11 kV	8
Total			**1648**

The difference between Table 1 and Table 3 is due to discrepancies within the database due to not all sites have a known HV switchgear type.

The types of LV switchgear installed include LV circuit breakers, busbar, links, fuses and isolators. Table 4 details the types of LV switchgear installed in the system.

Table 4: Low voltage switchgear installed in Aurora's distribution system as at August 2010

Description	Number Installed
B&S	4
English Electric	23
GEC	14
HEC	25
Mechanical Services	665
Merlin Gerin	297
Nilsen	67
Saifway	149
Standard Waygood	22
Total	**1266**

Difference between Table 1 and Table 4 is due to discrepancies within the database due to not all sites have a known LV switchgear type.

Ground mounted substations have an earthing system, which is essential for maintaining personnel and public safety and for correct operation of protection equipment. The fault level, protection clearing time and site soil resistivity dictate the extent of the earthing required.

In ground mounted substations the earthing system is typically a copper earth grid, possibly with associated earth pins. All metallic components of the installation, including the enclosure, are connected to the earthing system.

The purpose of the enclosure at a ground mounted substation site is to provide a secure location for the equipment and to provide for public safety. At some sites the enclosure also provides a method of oil-containment for transformer and/or switchgear oil.

Within Hobart CBD, some ground mounted substations have additional components installed, such as auxiliary protection systems, batteries and relays. Protection communications cables, known as pilot wire, provide the link between substations, specific switchgear and associated equipment.

5. AGE PROFILE

The age profile data was compiled using Aurora's Replacement Capital Expenditure Model (reference 4). The ages of the assets were calculated using the installation date of the transformer, since there is no individual information for site or switchgear installation dates.

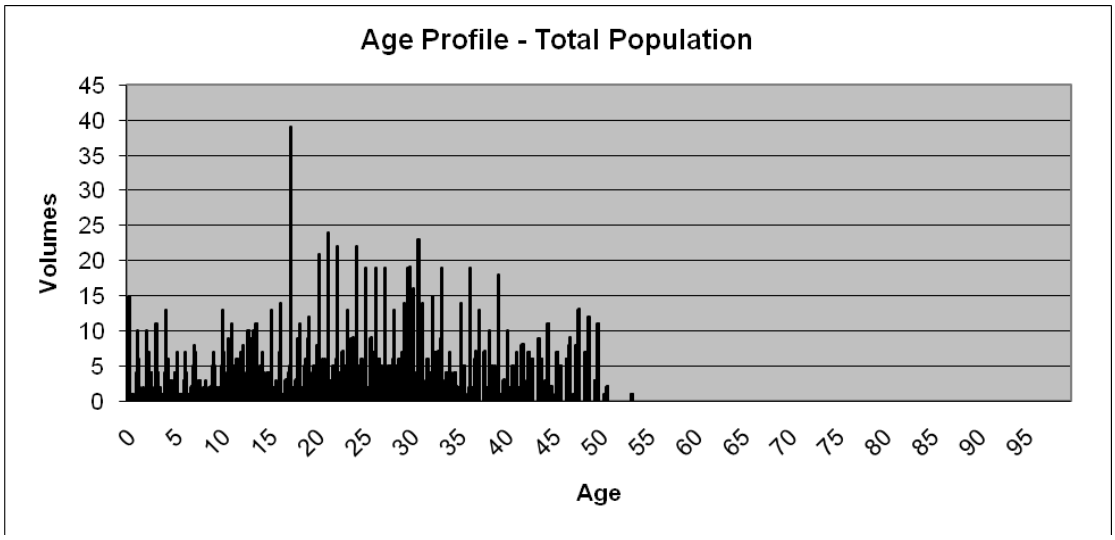

Figure 1: Total age profile in the distribution system as at August 2010

Although there is a fairly even spread of assets across the age profile, there is approximately 25% of assets that will reach or pass their expected life which ranges between 40 and 50 years, depending on the equipment, within the next 5 to 10 years. The large spike in volumes for assets aged around 17 years is suspected to be abnormality in data.

Ground mounted substation failures have minimal impact on SAIDI and SAIFI due to their smaller volumes in the system.

Assets with an age less than the average life across the whole asset class of twenty four are predominantly within padmount/kiosk type substations as shown in Figure 2.

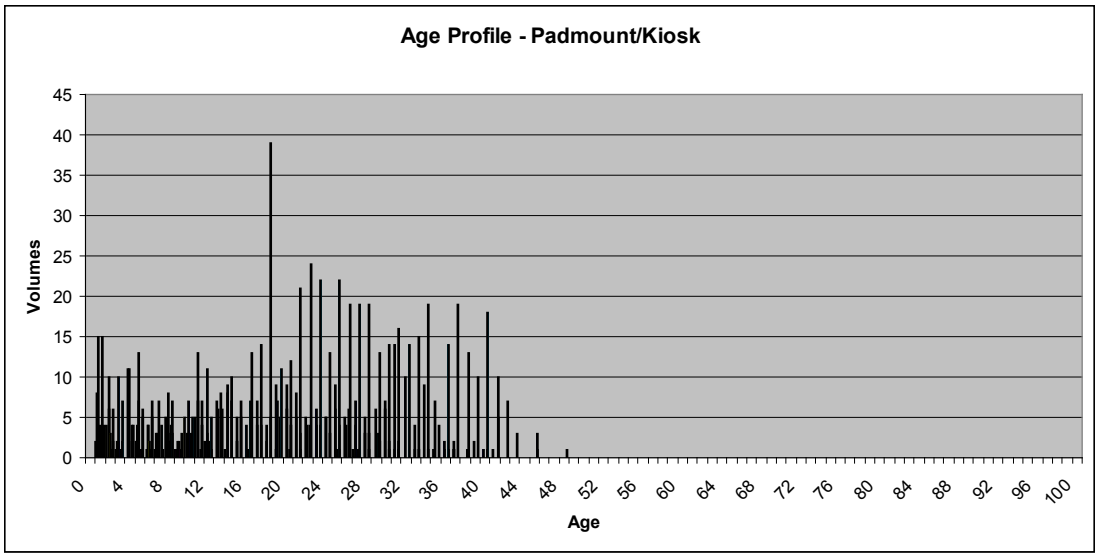

Figure 2: Padmount and kiosk age profile in the distribution system as at August 2010

The large concentration of assets volumes with an age between 20 and 40 above the average volume is partly due to Tasmanian Housing Department development in urban residential subdivisions that supported underground electrical infrastructure during the late 1970s. A strong focus on the south of Tasmania resulted in large numbers of 11 kV padmount and general ground mounted substations being installed which can be demonstrated in the large step change in volumes.

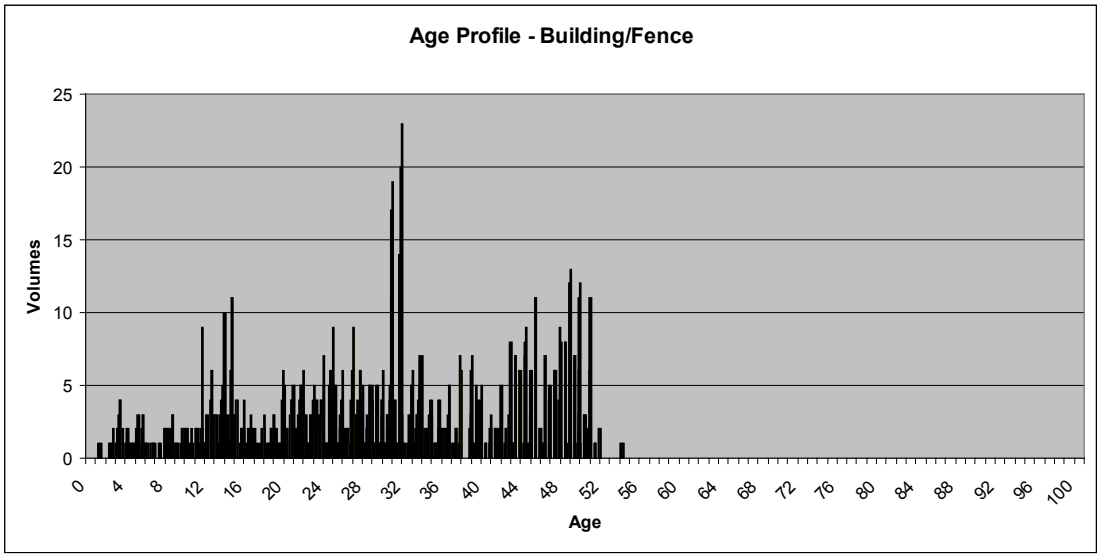

Figure 3: Building- and fence-type age profile in the distribution system as at August 2010

Building type substations represent the majority of the total population due to reach its expected life within the following five years. These types of sites can often represent the largest capital cost to replace due to the constraints associated with their surrounding environment.

6. FACTORS INFLUENCING ASSET MANAGEMENT STRATEGIES

The principal factors influencing asset management strategies are classified as per objectives set out in Section 2:

6.1 Minimise Cost of Supply to the Customer

- Ensuring cost effective trade-offs are made between pro-active and reactive maintenance practices;
- Maintenance activities cost effectively ensure a reasonable service life is achieved from the asset;
- Capturing adequate information on the assets to facilitate informed decision making; and
- Ensuring all risks are identified and have adequate management plans integrated into the business' practices.

6.2 Maintaining Network Performance

- As failure of this asset class generally impacts a large number of consumers and loads, it is crucial to maintain in-service failures to a very low level;
- Ensuring the general operational condition of the assets is maintained to an acceptable level for reliable function of switchgear when required; and
- Targeting activities in areas where targets are not being met.

6.3 Managing Business Operating Risks

- As the assets contain dangerous voltages in areas frequently visited by the general public, adequate security is maintained to restrict unauthorised access is a key consideration.
- Ensure earthing and protection systems are maintained to a confidence level that ensures these systems will operate if and when required

6.4 Complying with Regulatory, Contractual and Legal Responsibilities

- Ensure adequate monitoring and inspection activities to cover legislative compliance obligations.

The following is a brief description of the specific regulatory obligations directly influencing Aurora's management of ground mounted substations.

6.4.1 Compliance with Fire Standards

All building and vault type substations must comply with the Building Code of Australia (BCA) and AS 1851 Maintenance of Fire Protection Systems and Equipment (references 16 and 11).

Aurora is required to inspect and maintain all entry and exits, ventilation and building penetrations. These types of substations typically have one access door, which requires inspection.

Other equipment that forms part of the fire integrity of the installation and require inspection includes fire dampers and fire proofing of cables.

Vault and building integrated ground mounted substations pose a greater risk of damage and/or loss of distribution assets and other assets and injury to personnel or public in the event of fire. These substations are incorporated into other buildings making it easier for fire to spread to adjacent assets and because they are less accessible by Tasmania Fire Service (TasFire) to control the fire.

As at August 2010 Aurora has 21 ground mounted substations that have a CO_2 injection piping system to assist in extinguishing fire at these sites. This system relies upon TasFire supplying and maintaining a transportable CO_2 unit.

TasFire has indicated it will no longer supply the transportable CO_2 containers.

AS 2067 Substations and high voltage installations exceeding 1 kV a.c. (reference 9) requires all new substations holding less than or equal to 1000 litres of oil must have enclosure rated at Fire Resistance Level (FRL) 120/120/120, as defined in the BCA. Substations that hold greater than 1000 litres of oil must have an enclosure rating of FRL 120/120/120 and automatic fire suppression.

6.4.2 Sulphur Hexafluoride (SF_6)

As at August 2010, Aurora has 1045 ground mounted substation sites with switchgear containing SF_6.

In recent times concerns with the effect this green house producing gas has on the environment has resulted in the introduction of requirements for the reporting and disposal of SF_6.

Aurora is required to comply with The National Greenhouse and Energy Reporting Act 2008 (reference 18), which sets out a national framework for corporations to report greenhouse gas emissions and energy consumption and production from 1 July 2008.

Disposal of SF_6 is managed in accordance with Aurora's Environmental Management Procedure EW-M12-01 Disposal of SF_6 (reference 19) which reflects the requirements of the National Environment Protection Management Measure (NEPMS) and the Environmental Management Pollution Control Act 1994 (references 14 and 15).

6.4.3 Polychlorinated Biphenyls (PCBs)

Polychlorinated biphenyls (PCBs) were used in transformers and capacitors amongst other things from the 1930s to the 1970s. However, they were shown to be toxic and carcinogenic and have been banned in Australia in the 1970s.

Aurora manages PCBs in accordance with Aurora's Environmental Management Procedure EM-M09 Management of PCBs (reference 6), which reflects the requirements of the Australian and New Zealand Environment and Conservation Council (ANZECC) Polychlorinated Biphenyls Management Plan (reference 5). Both plans satisfy the legislative requirements of the TAS Environmental Protection & Pollution Act 1994 and the National Environment Protection Council Act 1994 (references 20 and 21).

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As part of the routine switchgear maintenance, if asset records indicate that the status of the oil in a transformer is 'unknown' then a sample of oil is taken from the transformer for PCB testing. If the PCB test results indicate PCB levels equal to or greater than 50 ppm, the transformer is proposed for removal from the system.

7. MANAGEMENT PLAN

7.1 Treatment Trade-Offs

7.1.1 Preventative Maintenance

There is a fundamental requirement for Aurora to periodically inspect the assets to ensure their physical state and condition does not represent a hazard to the public. Other than visiting the assets, there is no other economic solution to satisfy this requirement.

7.1.2 Preventative Corrective Maintenance versus Reactive Corrective Maintenance

Failures within Ground Mounted Substations may cause serious or catastrophic damage to the asset. These assets are generally located in close proximity to the public, so allowing failures to occur represents a real risk to the public and surrounding infrastructure. These assets also have a high unit value, so a preventative corrective maintenance program represents a cost effective alternative to a reactive corrective maintenance program.

7.1.3 Refurbishment

Where substation assets are removed from the network in good operating condition by activities such as capacity and power quality drivers, these assets are assessed for redeployment back into the network where such refurbishment is deemed to be an economic proposition.

7.1.4 Planned Asset Replacement versus Reactive Asset Replacement

Similarly to Section 7.1.2, a reactive replacement does not represent an attractive alternative to a planned renewal activity. Ground mount substations are predominately supplying high density urban, commercial or CBD communities, with a high service level expectation in the Tasmanian Electricity Code (reference 22). Also reactive replacements are generally several times more expensive, incurring overtime, call out penalties and additional repair costs to cable terminations and nearby infrastructure.

7.1.5 Non Network Solutions

Distribution Substations are a fundamental requirement of the network with no viable alternatives.

Other options do exist to minimise customer disruption, including temporary mobile generation substitution while an asset is out of service. Aurora currently has one mobile generator and has leasing arrangements in place to source additional units as required.

7.2 Preventative Maintenance

7.2.1 Routine Inspection and Monitoring

Aurora has had an inspection program in place for several years that ensures assets are monitored for general condition and security. The opportunity is also taken to capture loading data during this process to support the Capacity Management Planning processes. The frequency of inspection considers the varying risk profiles across the assets as listed in Table 5.

Table 5: Inspection frequency for Ground Mounted Substations

Classification	Frequency
CBD substations	Once per year (winter)
All other substations greater than 100% load	Once per year (winter)
All other substations less than 100% load	Once every two years (winter)

The timing of this inspection has been chosen to coincide with Tasmania's peak load (i.e. winter), as this will demonstrate how the assets are performing under maximum conditions.

7.2.1.1 Fire Suppression Compliance Inspection

To comply with Appendix G of AS 1851 Aurora is required to conduct monthly inspections of the fire panel and smoke alarms at all sites with a fire suppression system.

7.2.1.2 Fire and Exit Doors Inspection

The BCA also refers to Appendix G of AS 1851 for periodic inspections of fire doors and exit lights every three months.

7.2.1.3 Targeted Inspection and Monitoring

Specific risks within this asset class have been identified and require targeted risk mitigation strategies.

Following a sample audit of sites to review Aurora's information quality on earthing system condition, it has identified a need to improve the data quality held to ensure compliance to AS 2067 and ENA EG-0 Power System Earthing Guide (reference 23).

Accordingly, Aurora proposes to increase the level of earth site condition measurement from five to 10 sites per year commencing 2012/2013 financial-year. During the period 2010/2011 and 2011/2012, Aurora will provision a sum for the inspection and subsequent upgrade of these sites (if required). Aurora will review this information to determine if the proposed inspection levels are adequate for subsequent years.

7.2.1.4 Special Audits

This program is to audit assets when an emerging issue is identified throughout the year. This also includes SF_6 reporting requirements.

7.2.2 Routine Maintenance

Aurora's practice is to complete invasive routine maintenance on all ground mounted HV switchgear and distribution transformers on a four-year cycle.

This activity ensures that all functioning housekeeping activities are performed on the assets to keep them operating satisfactorily until the next maintenance cycle. The activity includes removal of vegetation build-up within the cabinets, thermal and partial discharge inspections and other general maintenance activities. Protection systems are also checked.

The program is also used to identify assets where condition has deteriorated to a level where renewal has become necessary and to monitor risks associated with specific programs identified within the asset category.

These are described in the following sections.

7.2.2.1 Asbestos

Aurora is required to comply with Workplace Health and Safety and Regulations 1998 and the National Occupational Health and Safety Commission Code of Practice for the Management and Control of Asbestos in Workplaces [NOHSC: 2018 (2005)] (references 13 and 17).

As at August 2010, Aurora has 633 substation sites that contain asbestos. These sites vary from building to pad mount type substations. Within these sites doors, enclosure material and LV switchgear may have Asbestos Containing Material (ACM).

Aurora created a register of these sites in 2009/2010 and has maintained an inspection program to specifically monitor the condition of the asbestos components. ACM approaching a friable condition are flagged for replacement. These practices ensure Aurora complies with required legislation.

7.2.2.2 Corrosion

Current maintenance programs have identified higher corrosion levels are exhibited on assets located in harsh environments such as those located in close proximity to coastal and also industrial areas. As at August 2010, Aurora has approximately 65 transformers within 20 metres of coastal areas or near highly corrosive industrial sites.

Trialling of alternate marine grade aluminium enclosures and protective (Jotacote) coatings is underway to assess economic benefits.

7.2.2.3 Safety/Security

Incident reporting has identified five incidents within the last three years that involved some form of unauthorised access to fibreglass padmounted substations. The doors of this type of enclosure are easier to lever off than normal steel enclosures. This exposes the public to equipment containing live parts. As at August 2010, there are approximately 250 sites with fibreglass enclosures in the distribution system.

These specific areas within the network have been identified as carrying a higher risk of unauthorised access due to vandalism and density of human traffic (e.g. schools). This risk is mitigated as part of the routine maintenance activities.

7.2.2.4 Vegetation

Vegetation protruding from outside of the enclosure into the substation equipment can cause a significant risk to the installation. Aurora has recorded three separate incidents over two years that have resulted in major equipment failure producing significant outage times. This risk is mitigated as part of the routine maintenance activities.

7.2.2.5 Graffiti

It is Aurora's practice is to remove all offensive graffiti within 24 hours of notification of the presence of the offensive graffiti. Extensive graffiti and graffiti covering substation signage is removed within the normal asset repair time frames.

7.2.2.6 Old Battery Systems

Older battery systems still require six monthly inspections based on current deterioration rates observed by field staff and communicated back the Assets Team. These batteries are progressively being replaced with modern equivalents that will reduce the level of site visits and associated costs.

7.2.2.7 Confined Spaces

The definition of a confined space is contained in Schedule 1 of the Workplace Health and Safety Regulations 1998.

Safe entry into confined spaces to perform work is governed by the requirements of AS 2865 Confined spaces (reference 10) and is called up as a direct reference in the Workplace Health and Safety Regulations 1998.

To comply with relevant legislation around confined space management, Aurora checks the accuracy of the confined space register and confined space labelling once every four years in conjunction with the switchgear maintenance.

7.2.2.8 Remote Control

Aurora has a program in place to remote control switchgear in specific locations. This program is managed within the System Performance Team.

Where a site has been remote controlled the batteries as part of the remote control system are replaced every four years at the same time as the switchgear maintenance.

7.2.2.9 System Spares

The systems spares funding is required for the management of reclaimed spares-equipment that is removed from the system for reasons other than age and condition and are able to be re-used within the system.

7.3 Asset Replacement

The key drivers for asset replacement are condition and specific issues and risks identified from the inspection and maintenance practices and investigations into the causes of asset failures.

These issues are described in the following sections.

7.3.1 Condition

Replacement is generally only chosen when replacement represents a more economic proposition to ongoing maintenance costs over the estimated remaining service life of the asset. These are identified from the maintenance and inspections activities and feed into the list of proposed capital expenditure projects for prioritisation. The total annual replacement rate is approximately 3.3% of the total population. Of this rate, 33.4% covers transformer and whole site replacement while the remaining 66.6% covers switchgear replacement. The long run average replacement for a 40 to 50 year asset varies between 2.5% and 2% accordingly. An increase from the nominal percentage is due to unprecedented failure exhibited in specific witchgear as well as new compliance standards introduced during the current regulatory period.

7.3.2 Siemens Switchgear Performance

Aurora Energy (formerly Hydro) began purchasing 8CK1 Siemens line switches and switch fuses in the early 1970s on a period contract, with 8CK2 units being purchased from mid-1975.

There has been a higher than expected failure rate of Siemens 8CK switchgear. In 2001, a management plan was put in place with special arrangements for maintenance of Siemens switchgear and a replacement program established.

Despite these measures, the condition of the switchgear has further deteriorated, with a live operating ban being placed on the units in October 2008. Aurora plans to remove all Siemens switchgear by the end of 2011/2012 financial-year. Prioritisation of sites is detailed in Appendix D.2.

7.3.3 Brown Boveri RGB24

Brown Boveri RGB24 units were installed from the late 1970s to early 1980s. The design of the rear epoxy spouts allows the collection of dirt and moisture over time (refer to Appendix B.2), which eventually causes insulation failure and flashover that leads to switchgear failure and outage of the entire site. Generally, complete switchgear replacement is required if this occurs.

Access to the spouts for cleaning cannot be performed unless the switchgear is fully dismantled.

There have been three recorded incidents of this nature, but anecdotal evidence from field staff has also indicated there has been other sites fail due to this type of fault that have not been recorded in Aurora's incident reporting system.

There has been a further three incidents associated with the RGB switchgear of a different nature, the most recent failure was attributed to a cable failure within the switchgear cubicle which caused the loss of the switchgear.

There are approximately 40 of these units remaining in the network as at August 2010 and are will be considered for preferential replacement or

refurbishments commencing in 2011/2012 and to be completed by 2019/2020. Prioritisation of sites is detailed in Appendix D.3.

7.3.4 Oil-filled Switchgear

Oil-filled switchgear was installed from the 1960s to 1980s. This type of switchgear is contained in building, fence and padmount type substations throughout the state, with a total population of approximately 327 sites as at August 2010.

The consequences of explosion of oil-filled switchgear are much greater than other types of switchgear due to the flammability of the oil, which creates a significantly higher risk to operator safety and damage to adjacent assets.

Additionally, there is the risk of environmental damage in the event of an oil spillage for sites that do not have oil containment facilities.

Aurora expects to have 311 sites with oil filled switchgear in service at the beginning of 2012/2013.

The proposed program constitutes in an overall increase in volumes to a new replacement rate of 31 per year over a 10-year period ending in 2021/2022. Reasons behind the increase are as follows:

- Siemens switchgear replacement program will be completed by the end of 2011/2012 financial-year, allowing for reprioritisation on oil filled switchgear replacement.
- The Electricity Supply Association of Australia *Guidelines for Reliability Assessment Planning* (reference 24) advises a failure rate of 0.04 failures per year for 11kV oil filled switchgear i.e. 1 failures every 25 years. The average year of installation for this type of switchgear occurred during the 1970s.
- The risk has been assessed as extreme.
- Analysis of Aurora's total population of oil-filled switchgear as at August 2010, demonstrates 33 sites that suffice a high priority based on Aurora's oil-filled switchgear prioritisation matrix (Appendix D.7). The number of sites with high priority reflects the replacement rate proposed for oil filled switchgear.

As part of the four-yearly switchgear maintenance and visual inspection during load checks, each oil filled switchgear site will be monitored for ozone and noise. If a site is found to have any issues, it will be reprioritised accordingly.

The replacement program will result in a reduction of operational costs as modern switchgear is classified as "maintenance free" due to minimal maintenance requirements and no oil replacement. It is estimated from current maintenance on oil filled switchgear that a saving of $71,000 per year will be saved in operational costs with the removal of this switchgear.

The replacement from oil filled to air/gas switchgear also allows for added functionality such as remote controlling.

7.3.5 Fire/Explosion Risk

A sample audit conducted in 2010/2011 financial year identified 21 assets that are located closer to neighbouring buildings and represent higher consequential risks to the business should they fail catastrophically. The quantity of oil in the assets is also considered to prioritise these assets for renewal/relocation, with a targeted rate of treatment of up to 3 sites per annum.

7.3.6 Fire Suppression System

In liaising with TasFire, Aurora requires a program to progressively convert all existing CO_2 systems in vault type and building integrated substations to a new Stat-X fire suppression system. It is planned to do four sites per year commencing in 2011/2012 and to be completed by 2016/2017 financial year.

Appendix D.6 details the prioritisation scheme for this program of work.

7.3.7 Oil Containment

Distribution transformers contain a mineral insulating oil for both electrical insulation of the internal components and cooling.

AS 2067, Clause 6.7.11 requires that every high voltage installation containing equipment with more than 500 litres of a liquid dielectric such as transformer oil, shall have provision for containing the total volume of any possible leakage and meet the overall objectives of Appendix H of AS 1940 The storage and handling of flammable and combustible liquids (reference 8).

Older installations do not have the same level of oil containment controls as modern installations and accordingly represent a higher level of risk to the environment should an asset fail.

Aurora has experienced over four incidents in the past four years, where the oil has not been contained on site due to no oil containment.

Key considerations when assessing specific risks at a site include consideration of the local environment (e.g. waterways) and amount of oil contained on the site. Appendix D.1 provides further details on the risk assessment matrix used.

Two of the four incidents relating to oil spillage occurred in close proximity to major rivers. As at August 2010, Aurora has 25 sites with oil filled switchgear which have been identified as high priority and these sites will be included in the capital expenditure prioritisation process for remedy, with a targeted rate of 4 sites per annum commencing in 2012/2013 financial year. Appendix D.1 details the prioritisation used for the oil containment program.

7.3.8 LV Switchgear – Live Front Boards

Many of the LV boards installed in Aurora's building and vault type substations are of open-type or live front construction. The construction of these boards

means that live parts of the equipment are easily accessible and pose a risk to personnel safety. Many of these boards are located in cramped operating conditions with little access for escape in the event of contact with live parts.

Whilst these open-type or live front boards met the standard of the day they were installed, they do not reflect the current level of safety expected in modern installations to AS/NZS3000 Electrical Wiring Rules (reference 12).

As at August 2010, Aurora has a total of 310 sites that contain live front boards and has audited these to identify sites where there is a higher risk to operator safety as a result of the substation configuration, and this risk drives increased consideration for earlier renewal of these assets. The replacement of these assets is a continuation of an existing program and the current replacement rate of six per year is proposed during 2012/2013 through to 2019/2020. This rate will remove 30 out of the 310 sites that have been identified as high risk based on Aurora's live front board replacement prioritisation (Appendix D.8).

7.3.9 LV Switchgear – Asbestos Arc Chutes

This is a continuation of an existing program to remove this type of LV circuit breaker as it contains asbestos in the arc chutes.

It is anticipated that this program will continue at a rate of six sites per year, with all asbestos arc chutes to be removed by the end of 2013/2014.

The current rate is supported as follow:

- Current results for ACM reaching a friable state have not exceeded the current rate of replacement;
- Removal of the asbestos Arc Chutes circuit breakers allows for condition monitoring functionality on the LV board; and
- Replacement of asbestos equipment reduces the total number of sites to be audited under asbestos inspections, resulting in a decrease in operational expenditure.

7.3.10 Asbestos

As identified above, these assets are replaced once their condition reaches an unacceptable level of risk. Aurora's periodic ACM inspection has identified approximately one site per year approaches a friable condition. The current rate will be used for the period commencing 2012/2013 to 2016/2017 and will be monitored and reviewed yearly to determine if the replacement rate is still appropriate.

7.3.11 Polychlorinated Biphenyls (PCBs)

PCB contamination is used as one of the drivers for transformer replacement. Assets identified with unacceptable levels of PCBs are identified during the maintenance programs and proposed for replacement. The 2010/2011

maintenance program identified eight sites with elevated levels of PCB and are flagged for replacement.

7.3.12 New Battery Systems

Older battery systems are replaced with modern equivalents upon failure. The new battery systems' batteries have an expected life of five-year. Aurora replaces these batteries every four years in alignment with switchgear maintenance to avoid costs associated with specific site visits.

7.3.13 Ferro-resonance

Ferro-resonant circuits pose a risk of damage and/or loss of distribution assets and injury to personnel or public and increase reliability performance. While risks can be controlled adequately using operating procedures, where these introduce an unacceptable level of impact to the operation of the network, these are considered for accelerated replacement.

There are three set conditions that must exist for ferro-resonance to occur:

1. Presence of a capacitance in series with the non-linear inductance;
2. Unloaded or lightly loaded conditions, and
3. At least one single-phase operation of a switch or protection device in a three-phase system.

There are approximately 160 ground mounted substation sites within the 11 kV and 22 kV distribution network as at August 2010, where ferro-resonance may be a potential issue:

- Ground Mounted Substations containing Hazemeyer MD4 HV switchgear
- Ground Mounted Substations connected to the overhead system via underground cables and protected by single-phase switching devices such as single-phase Expulsion Drop Out fuses (EDOs).

Aurora has an ongoing program in place to replace sites that may be susceptible to ferro-resonance. The rate of replacement as at August 2010 is one site per year will continue since operational constraints associated with current ferro-resonance sites is acceptable, i.e. probability of outage/switching required at remaining sites is low.

Further details on ferro-resonance can be found in the Ferro Resonance Management Plan (reference 7).

7.4 Fault Replacement

In addition to the proactive replacement programs, Aurora experiences a number of switchgear failures each year due to random failures and faults. These are the results of incidents such as lightning strikes, vehicles hitting substations and one off equipment failures.

Incident reporting reports an average rate of approximately 11 incidents per year. However the majority of these incidents relate to other specific programs already accounted for, therefore the remaining total average of approximately 4 incidents per year will be used for budgeting future fault replacements.

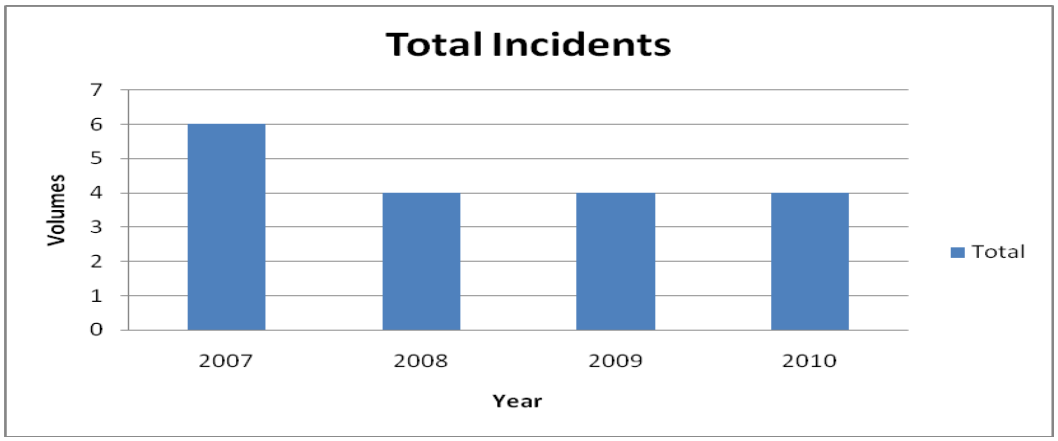

Figure 4: Total incidents recorded within a five year period

7.5 Sulphur Hexafluoride (SF_6)

To comply with legislative requirements for the disposal of redundant equipment containing SF6, Aurora is required to comply with NEPM National Environment Protection Measure (NEPMS) and the Environmental Management Pollution Control Act 1994.

Equipment containing SF_6 that is removed from service is stored at the nearest depot until a storage container is full and then transported by an accredited transportation corporation interstate for SF_6 recovery and disposal of units at an accredited end of life facility.

Historical values indicate approximately six units of ground mounted substations and pole mounted assets are recovered and disposed of every year.

7.6 Earthing

The information on the condition of the earthing systems at ground mounted substations is limited.

Aurora's substations are located in a wide variety of situations. Aurora considers the following types of sites to pose an increased risk to the public:

1. Substations within 100 m of swimming pools because of the large number of public gathered at these sites in a wet environment with no footwear (approximately 15 sites);
2. Substations within 15 m of schools because of the large number of children (who are more susceptible to electric shock than adults) gathered at these sites (approximately 171 sites); and

3. Substations within 15 m of shopping centres and bus stops because of the larger number of people that may gather at these sites (approximately 100 sites).

Aurora has an ongoing program in place to perform earthing injection testing on ten sites per year.

Sites will be selected for earthing injection testing based on the prioritisation given in Appendix D.5).

7.7 Safety/Security

Aurora's risk prioritisation (Appendix D.9) has identified approximately 67 sites that are in close proximity to schools, bus stops and general highly populated areas where the probability of unauthorised entry increases due to the nature and location of these sites. Aurora will introduce a program to reinforce all sites within a five-year period commencing in 2012/2013 financial-year. The proposed rate of reinforcement is 50 sites per year.

8. REVIEW OF HISTORICAL PRACTICES

Aurora's asset management practices on these assets have been stable for a number of years and are generally considered to be providing a well-balanced trade-off between maintenance and capital expenditure. In particular, Aurora believes the practices of condition based renewal, driven by asset inspection and maintenance practices are providing well-founded decision making.

The level (cost) of repair outside programmed maintenance appears stable over the past five years, indicating the existing frequency of planned maintenance cycles is reasonable and the practices are capturing and resolving the issues during the visit to the site.

Similarly the actual programmed maintenance cost each year is reasonably stable, although the last 2 years are showing a slight increase in planned maintenance compared to corrective maintenance (repair) activities.

A need to improve the decision making data for earthing installation upgrades has however been identified as an area that requires additional focus in the coming period.

Overall the level of reactive failures experienced on the network is considered reasonable against industry practices.

9. PROPOSED OPEX PLAN

It is proposed to continue with the current asset management practices, but with the some additional expenditure. This step change is largely contributed due to compliance requirements for fire door inspections, confined space and earth site testing.

A reduction from the current inspection frequency for CBD substations will reduce the costs associated with this category and through the introduction of

recent investment in improved information systems there is opportunity to further reduce current frequency levels.

Replacement of the older battery systems in substations will reduce the level of maintenance required in this category. These initiatives are expected to offset the additional costs for earth testing.

Table 6: OPEX for period between 2007/2008 and 2016/20017 financial years

GMS	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Inspection	$27,075	$188,623	$350,388	$ 350,000	$ 355,000	731,022.42	722,350.67	728,345.26	729,964.17	723,360.52
Maintenance	$9,405	$891,028	$1,003,696	$ 939,484	$ 939,484	1,016,875.49	1,012,661.72	991,014.61	989,897.21	980,906.63
Repair	$27,526	$455,673	$360,346	$ 295,000	$ 270,000	354,564.46	351,207.81	352,603.75	351,955.18	347,417.32
Actual $$	$64,006	$1,535,323	$1,714,429	-	-					
Proposed $$	$1,180,220	$ 1,447,951	$ 1,606,535	$ 1,574,484	$ 1,564,484	2,102,462.37	2,086,220.20	2,071,963.62	2,071,816.56	2,051,684.47

10. PROPOSED CAPEX PLAN

The following values were obtained using Aurora's Capital Expenditure Model (reference 4). Using the Estimated Life Expectancy feature of the model for this asset category, the following envelope of renewal investment is required over the following 20 years to maintain the asset class at a stable Remaining Life Expectancy (RLE).

Figure 5 shows the outputs of Aurora's capital expenditure model for the ground mounted substations, taking into account condition, risk and age. The model forecasts capital investment of $25.5m over the next regulatory period however, the values used for age are higher than those proposed by the regulator. A total CAPEX of $33.3m would be anticipated if the regulated life expectancy was used.

Aurora's proposed expenditure for the next regulatory period is $26.7m (capital) and $10.4m (operational).

This spend is greater than the model forecast due to Aurora's risk and condition based approach to asset renewal and maintenance, which seeks to remove the risk of oil filled switchgear from the system and gain maintenance efficiencies by replacing it with remote control capable switchgear.

The projected program can be discounted slightly due to complementary activities arising from assets being replaced due to capacity and power quality drivers.

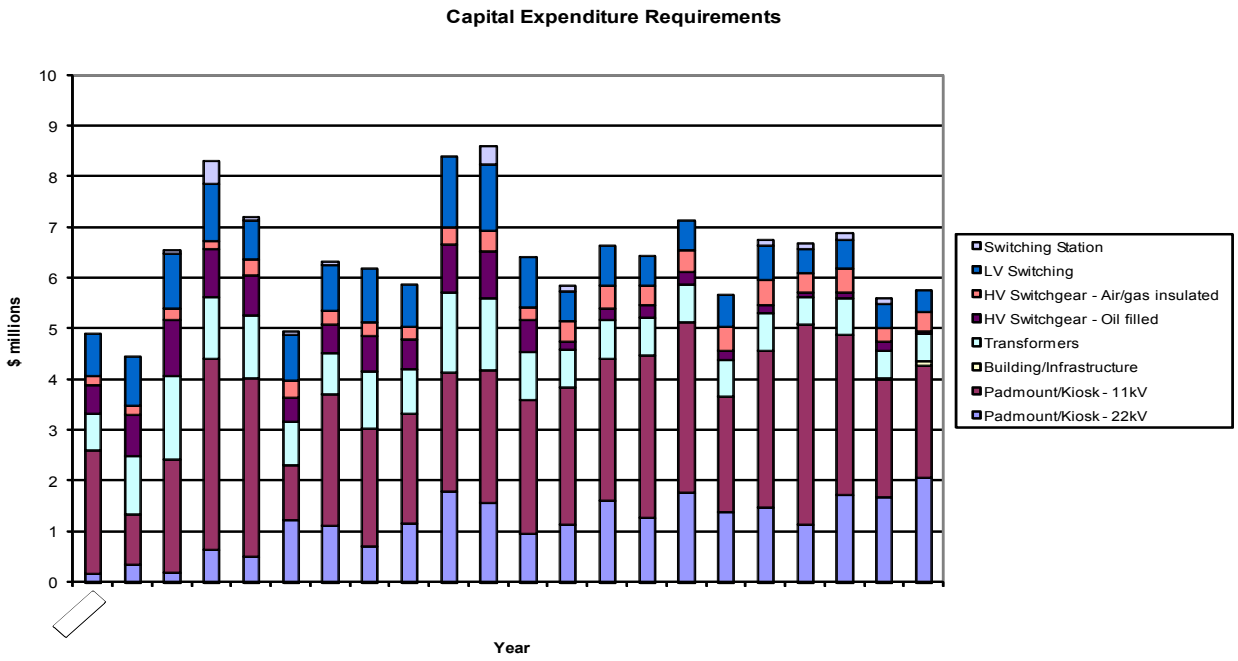

Figure 5: Forecast capital expenditure based on age profile information

When considering the bottom up drivers for asset replacements based on current condition data, field failure rates and prudent risk management, Aurora proposes that the above envelope can be discounted to the following levels without representing excessive risk or service level consequence to consumers. Both these areas will be monitored carefully to ensure these assumptions remain valid.

Table 7: CAPEX for period between 2007/2008 and 2016/2017 financial years

GMS		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Non Demar	HV/LV	$183,994	$800,804	$2,883,485	$3,221,911	$3,096,139	$2,069,932	$2,062,641	$1,810,521	$1,809,321	$1,800,923
	SITE(incl TX)	$515,699	$2,491,224	$4,057,795	$4,558,505	$3,420,000	$2,501,193	$2,500,866	$2,503,699	$2,240,413	$2,493,172
Specific Iss	SIGMS						$986,204	$983,865	$984,837	$984,385	$981,223
Actual $$		$699,693	$3,292,028	$6,941,280	$7,780,416	-					
Proposed $$		$1,248,319	$4,686,519	$9,120,000	$7,247,070	$6,516,139	$5,557,329	$5,547,371	$5,299,057	$5,034,119	$5,275,318

11. CAPEX–OPEX TRADE OFFS

Many operating expenditure programs identify assets, which require replacement for condition-based reasons. An example of this is the earthing system auditing program, where this program may lead to a requirement for capital expenditure on the earthing system.

There is a positive relationship between these two categories, in that the larger the scope and breadth of the inspection program, the larger the number of condition-based replacements that will be identified. In addition, the greater the number of assets replaced, the smaller the number of assets in the future that will be identified during the routine maintenance program as requiring replacement.

Other key interactions between the capital expenditure and operating expenditure exists when older equipment with higher maintenance requirements are replaced with new equipment with lower maintenance requirements, such as battery systems and oil-filled switchgear.

12. ASSET MANAGEMENT INFORMATION

Aurora maintains records of underground assets through the periodic routine testing and inspection programs providing the following information. The equipment details and attributes are predominantly recorded within FRAMME / WASP. These being the two integrated asset management systems, however there are smaller data-sets in MS Access and Excel that currently store other information relating to the asset and its condition.

A data capture initiative in the last 3 years has addressed many of the issues previously identified, with a generally good level and quality of data for assets in these categories.

13. RESPONSIBILITIES

Maintenance and implementation of this management plan is the responsibility of the Thread Leader – Ground Mounted Substations.

Approval of this management plan is the responsibility of the Group Manager – Asset Performance and Information Manager

14. REFERENCES

1. Management Plan 2011: Zone Substations (NW-#30161548)
2. Management Plan 2011: High Voltage Regulators (NW-#30161495)
3. Management Plan 2011: Overhead System and Structures (NW-#30161322)
4. PD2012 Capex Model - Dollars: Ground Mounted Substations (excluding regulators) (NW-#30160063)
5. Australian and New Zealand Environment and Conservation Council (ANZECC) Polychlorinated Biphenyls Management Plan (Revised Edition April 2003)
6. EM-M09 Management of PCBs (CO-#10369201)
7. Management Plan: Ferro Resonance (NW-#30060094)
8. AS 1940 The storage and handling of flammable and combustible liquids
9. AS 2067 Substations and high voltage installations exceeding 1 kV a.c.
10. AS 2865 Confined spaces
11. AS 1851 Maintenance of fire protection systems and equipment
12. AS/NZS 3000 Electrical installations (known as the Australian/New Zealand Wiring Rules)
13. Workplace Health and Safety Regulations 1998

14. The National Environmental Protection Measures (NEPMS)
15. The Environmental Management and Pollution Control Act 1994
16. Building Code of Australia
17. Code of Practice of the Management and Control of Asbestos in Workplaces [NOHSC: 2018 (2005)]
18. The National Greenhouse and Energy Reporting Act 2008
19. EW-M12-01 Disposal of SF6 Equipment (CO-#10031177)
20. TAS Environmental Protection & Pollution Act 1994
21. National Environment Protection Council Act 1994
22. Tasmanian Electricity Code
23. ENA EG-0 Power System Earthing Guide
24. The Electricity Supply Association of Australia Guidelines for Reliability Assessment Planning

Appendix A SF_6 Quantities

Make	Model	Function		Total units	SF6 (kg)	Total (kg)
Merlin Gerin	RM6	2	Integrated	3	1.0000	**28**
Merlin Gerin	RM6	3	Integrated	82	1.4280	**142.8**
Merlin Gerin	RM6	4	Integrated	6	1.9770	**15.816**
Merlin Gerin	SM6	Switch	Extendible	233	0.2100	**49.98**
Merlin Gerin	SM6	CB (tx)	Extendible	139	0.3480	**50.46**
Yorkshire	YSF6		Extendible	10	0.2100	**2.1**
Asea Brown Boveri	CTC		Integrated	63	4.5030	**360.24**
Asea Brown Boveri	CTCC		Integrated	8	6.4000	**51.2**
Asea Brown Boveri	SAFEPLUS RMU		Integrated	1	3.2400	**3.24**
Asea Brown Boveri	SAFERING		Integrated	2	3.2400	**6.48**
Fluokit	M C10	Switch	Extendible	281	0.9700	**272.57**
Fluokit	M C40	Switch Fuse	Extendible	215	0.9700	**208.55**
DT1-72.5kV-Dead Tank	DT1-72.5kV			2	6.5000	**13**
Nulec Recloser	N27& N24	Recloser		225	1.8000	**405**
Reyrolle	ESR	Recloser		3	1.0000	**3**
Nulec Load Break Switch (LBS)	RL27	Switch		75	1.0000	**75**
Sectionaliser Nulec	RL27	Switch		7	1.0000	**7**
NGK Load Break Switch (LBS)		Switch		1	1.0000	**1**
unknown		Recloser		7	1.8000	**12.6**
						1708.036

This table indicates the number of equipment that contains SF_6 and the total corresponding SF_6 gas in kg

Appendix B Photos of Equipment Issues

B.1 Substation with Fire Risk to Adjacent Building

B.2 RGB Epoxy Spouts

The epoxy spouts contained within the RGB switchgear that failed due to dust and moisture.

Appendix C Stat X Technical Specifications

Fire Safety prevent | detect | contain | escape™

Stat-X PATENTED

Electrically Operated Units

Fire Detection | Fire Alarm Monitoring | **Fire Suppression** | Emergency Exit Lighting

Features

- Significantly more effective than alternative extinguishing agents
- Environmentally friendly - Zero Ozone Depletion Potential (ODP) and no Global Warming Potential (GWP)
- Easy to install - no pressure vessels, piping, or associated expensive installation labour
- Very low maintenance
- Provides reliable, cost effective protection for a wide range of fire hazards
- Tested and Listed to UL Standard 2127
- CSIRO ActivFire listed
- Suitable for enclosed facilities and local applications
- Safe for personnel - non-harmful to personnel at design application rates
- Safe for valuable equipment - will not harm electronic equipment or magnetic media
- Post fire cleanup is minimal - aerosol suspends in air for quick and easy venting after discharge
- Compact – up to a 90% reduction in space and weight requirements compared to gaseous systems

Applications

Due to their fast response time, low fire extinguishing concentration, and environmental safety, Stat-X fire suppression systems may be used in critical applications across a wide range of industries. Aerosol generators are currently protecting and are suitable for use in:

- Telecommunications facilities
- Flammable liquid stores
- Process control rooms
- Turbine and generator enclosures
- PABX rooms
- Marine engine rooms and machinery spaces
- High value mobile equipment
- Power plants
- Data processing facilities
- CNC machines
- Electrical cabinets

Operation / Description

Upon detection of a fire, Stat-X generators can be activated either manually or automatically from a suitable electrical releasing device. Upon activation, the generators produce an exceptionally effective, ultra-fine, potassium based aerosol. Unlike gaseous systems, Stat-X aerosol generators are very cost effective to install and maintain - as they do not require the pressure vessels, piping or expensive installation costs associated with other extinguishing systems. Space and weight requirements are minimal. On an agent weight basis, Stat-X aerosol is ten times more effective than gaseous agent alternatives. The Stat-X generator's effectiveness is a function of its patented design, aerosol composition, and ultra-fine particle size. Fire suppression is rapidly achieved through interference between the ultra-fine aerosol particulate and the flame's free radicals – terminating propagation of the fire. Stat-X aerosol generators are virtually maintenance free and have a service life of over 10 years. The low installation cost also makes them an extremely cost effective fire protection solution.

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Chubb
A UTC Fire & Security Company

Appendix D Prioritisation Tables

D.1 Oil-containment Prioritisation Matrix

Condition	State	Rating
Volume of oil on site	<500 l	0
	≥ 500 l	2
Number of transformers	1	1
	≥ 2	0.5
Proximity to waterway	≤ 10 m	2
	< 50 m	1
	≥ 50 m	0
Town water supply	Yes	1
	No	0
Environmentally sensitive area	Yes	1
	No	0
PCB contaminated	> 2 ppm	1
	≤ 2 ppm	0

D.2 Siemens Switchgear Replacement Prioritisation Matrix

Priority	Description
1	Open points, as identified by Distribution Operations
2	Sites with maintenance issues, as identified by Network Services
3	All other sites

D.3 RGB24 Switchgear Replacement Prioritisation Matrix

Priority	Description
1	Open points, as identified by Distribution Operations
2	Sites with maintenance issues, as identified by Network Services
3	All other sites

D.4 Transformer Replacement Prioritisation Matrix

Condition	State	Rating
Substandard clearance	Yes	3
	No	0
Exposed bushings in fence type substation	Yes	1
	No	0

Condition	State	Rating
Corrosion	Bad	3
	Mild	1
	None	0
PCB contamination	≥ 50 ppm	8
	> 2 ppm	1
	≤ 2 ppm	0

D.5 Earthing Testing Prioritisation Matrix

Priority	Description
1	Swimming pools (100 m)
2	Schools (15 m)
3	High pedestrian areas (15 m)
4	All others

D.6 Fire Suppression System Installation Prioritisation Matrix

Priority	Description
1	Vault type sites
2	First floor sites
3	Ground floor building integrated

D.7 Oil-filled Switchgear Replacement Prioritisation Matrix

Condition	State		Rating
Substation Type	Vault		2
	Building Integrated		1
	Others		0
Substation Location	CBD		3
	High Pedestrian areas		2
	Proximity to water ways	≤10m	1.5
		<50m	1
		≥50m	0
Substation Size (number of Transformers)	>2		2
	2		1
	1		0
Total Population of HV Switchgear Type	<10		1
	Other		0
Operational Configuration	HV open point		1
	No HV open point		0

Condition	State	Rating
Frequency of Operation	Highly operated sites	1

D.8 Live Front Board Replacement Prioritisation Matrix

Priority	Description
1	Exposed parts within 300mm of entry door
2	Restricted Operating area

D.9 Enclosure Safety/Security Prioritisation Matrix

Priority	Description
1	Schools
2	Highly prone vandalism areas
3	All others