Asset Management Plan

High Voltage Switchgear

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Responsibilities

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The approval of this document is the responsibility of the General Manager, Strategic Asset Management.

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- Implementation All TasNetworks staff and contractors.
- Compliance All group managers.

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1 Purpose

The purpose of this document is to describe for HV switchgears and related assets:

- TasNetworks' approach to asset management, as reflected through its legislative and regulatory obligations and strategic plans;
- The key projects and programs underpinning its activities; and
- Forecast CAPEX and OPEX, including the basis upon which these forecasts are derived.

2 Scope

This asset management plan covers all indoor and outdoor high voltage switchgear operating at 44, 33, 22, 11 and 6.6 kV within TasNetworks owned substations for a ten year rolling planning period. The objective of this plan is to maintain and minimise business risk to acceptable levels by achieving reliable asset performance at minimal life-cycle cost.

3 Strategic Alignment and Objectives

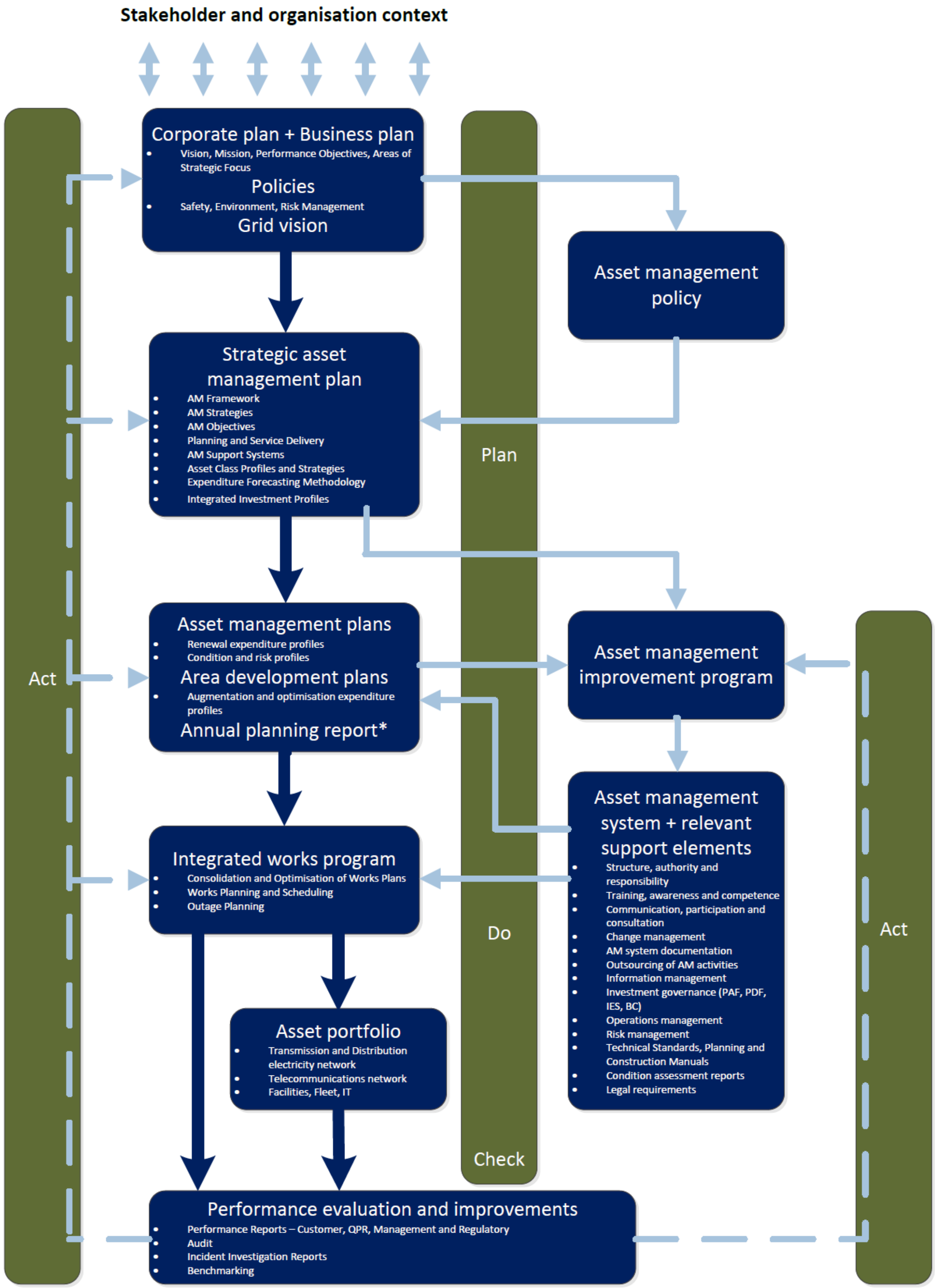
This asset management plan has been developed to align with both TasNetworks' Asset Management Policy and Strategic Objectives. This management plan describes the asset management strategies and programs developed to manage the HV switchgears, with the aim of achieving these objectives.

For these assets the management strategy focuses on the following objectives:

- Safety will continue to be our top priority and we will continue to ensure that our safety performance continues to improve
- Service performance will be maintained at current overall network service levels, whilst service to poorly performing reliability communities will be improved to meet regulatory requirements
- Cost performance will be improved through prioritisation and efficiency improvements that enable us provide predictable and lowest sustainable pricing to our customers
- Customer engagement will be improved to ensure that we understand customer needs, and incorporate these into our decision making to maximise value to them
- Our program of work will be developed and delivered on time and within budget.

The asset management policy and strategic objectives are outlined within the Strategic Asset Management Plan. Figure 1, from the Strategic Asset Management Plan, represents TasNetworks documents that support the asset management framework. The diagram highlights the existence of, and interdependence between the, Plan, Do, Check, Act components of good asset management practice.

Figure 1: TasNetworks asset management documentation framework



* The Annual Planning Report (APR) is a requirement of sections 5.12.2 and 5.13.2 of the National Electricity Rules (NER) and also satisfies a licence obligation to publish a Tasmanian Annual Planning Statement (TAPS). The APR is a compilation of information from the Area Development Plans and the Asset Management Plans.

4 Asset Information Systems

4.1 Systems

TasNetworks maintains an asset management information system (AMIS) that contains detailed information relating to the HV switchgear population. AMIS is a combination people, processes and technology applied to provide the essential outputs for effective asset management, such as:

- Reduced risk;
- Enhanced transmission system performance;
- Enhanced compliance, effective knowledge management;
- Effective compliance, effective knowledge management;
- Effective resource management; and
- Optimum infrastructure investment.

AMIS is a tool that interlinks asset management processes through the entire asset life-cycle and provides a robust platform for extraction of relevant asset information.

Asset defects are recorded directly against the asset registered in the asset management information system (WASP). The record captures the date of the defect in order to report the age of the device when the defect occurred and categorised as either a “failure” or an “error” etc. A defect is an imperfection that can cause a failure that was a result of the manufacture or breakdown of the device and sometimes is the result of human intervention or poor installation

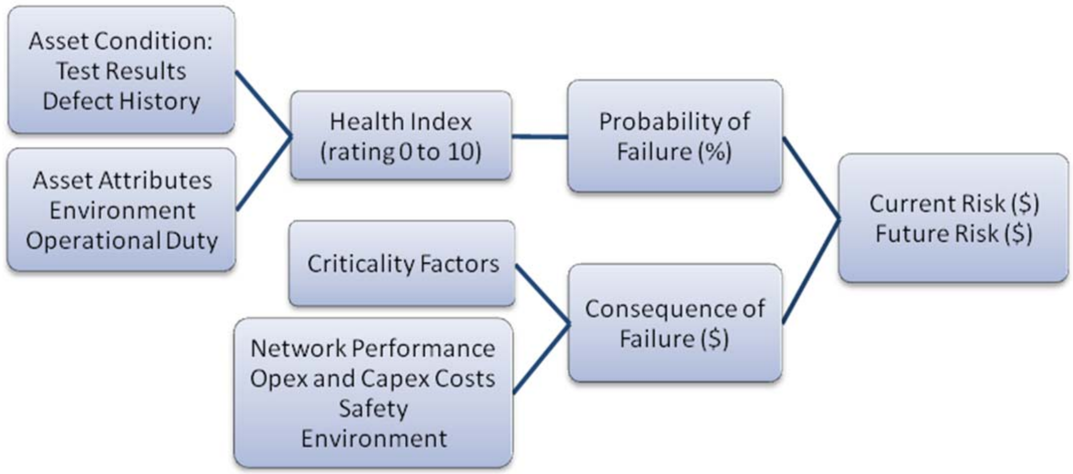
4.2 Condition Base Risk Management

In late 2010 TasNetworks engaged EA Technologies to implement a condition based risk methodology tool known as CBRM. EA Technologies is a UK based consultancy company with decades of asset management experience within the electricity industry.

TasNetworks intends to continue to use the Condition Based Risk Management (CBRM) tool to analyse HV switchgear assets and determine the effects of risk and cost trade-offs when considering asset replace and refurbish type decisions. Most of the final analysis is based on cost.

Condition based asset risk is the product of probability of failure, consequence and circuit criticality as details in Figure 2.

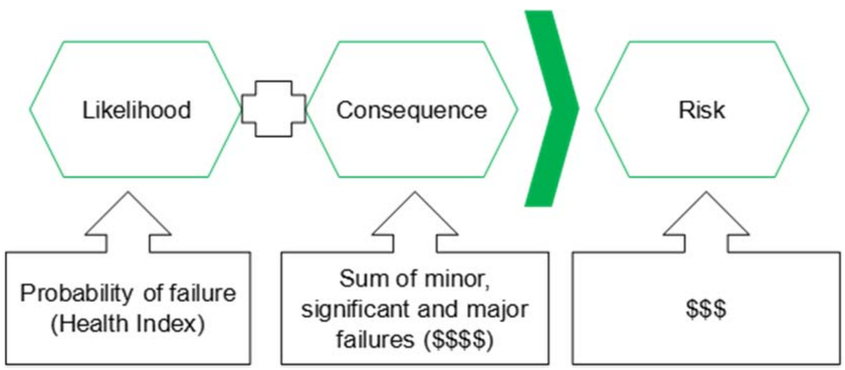
Figure 2: Asset Risk Framework



As with every risk decision, there are two main inputs, being likelihood and consequence.

Figure 3 shows what CBRM considers as the two risk inputs.

Figure 3: Risk derivation for CBRM



CBRM calculates the likelihood, or the probability, of failure of an asset by deriving a Health Index (HI). The HI of an asset is a means of combining information that relates to its age, environment and duty, as well as specific condition and performance information to give a comparable measure of condition for individual assets in terms of proximity to End of Life (EOL) and Probability of Failure (POF).

Once a HI for an asset is derived, a POF can be found. Notionally, the POF is an exponential function as shown in Figure 4 and Figure 5.

Figure 4: Deriving a probability of failure

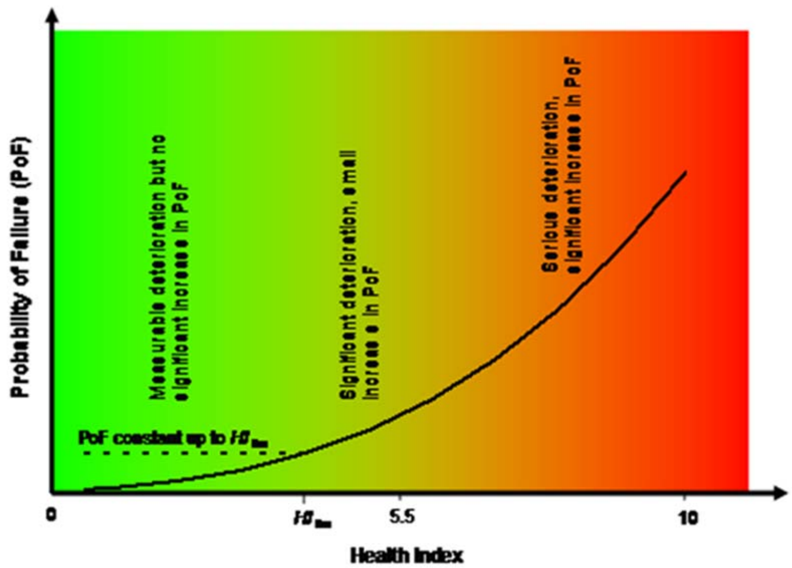


Figure 5: Health index interpretation

Condition	Health Index	Remnant Life	Probability of Failure
Bad	10	At EOL (<5 years)	High
Poor		5 - 10 years	Medium
Fair		10 - 20 years	Low
Good	0	>20 years	Very low

The health index is based on asset condition data such as the average defect age, manufacturer support, spares availability, maintenance complexity and technology.

Any asset that has a HI of above 7 is expected reach end of life in less than five years. Any asset with a HI above five is expected to reach end of life in the coming ten years.

Assets with a low HI, even up to five, have quite a low probability of failure, but that increases dramatically at higher HIs. The equation and steepness of this curve is calculated independently for each asset based on input data.

The consequences of a failure for each asset are calculated by considering the effects of safety, environment, repairs effort, replacement difficulty and potential loss of load. The consequences are all evaluated in dollar terms which allow the consequences to be summed together.

The combination of the probability of failure and the consequences provides the calculated risk, in dollar terms, for each asset.

In addition, the HI and POF can be predicted for future years. Consequently, risk can also be recalculated for future years.

The analysis of present versus future health and risk is the real power of the CBRM tool.

At present only power transformers have been integrated fully into the CBRM tool. Several other asset classes have been partially setup. It is expected that HV circuit breakers will be added into the CBRM tool in the near future

4.3 Asset Information

The following AMIS standards provide additional information relevant to HV Switchgear:

- R17042 WASP Asset Register – Data Integrity Standard – Circuit Breaker;
- R17054 WASP Asset Register – Data Integrity Standard – Fuse Switch;
- R16963 WASP Asset Register – Data Integrity Standard – Disconnector;
- R16975 WASP Asset Register – Data Integrity Standard – Earth Switch;
- R17028 WASP Asset Register – Data Integrity Standard – Voltage Transformer phase
- R17100 WASP Asset Register – Data Integrity Standard – Voltage Transformer
- R16971 WASP Asset Register – Data Integrity Standard – Current Transformer
- R16965 WASP Asset Register – Data Integrity Standard – Current Transformer phase

4.3.1 AM8 Condition data

An initiative within the Asset Performance and Strategy team was completed in 2016 to review key asset condition and maintenance regimes to assess their capability for asset condition being the basis for setting spending priorities. This initiative was referred to as AM8.

Condition based assessments provide a quantitative means to assess asset condition, their risk and failure probabilities and a basis to justify mitigation measures. Condition assessments are used to produce risk indices for assets and / or asset classes and provide a basis for asset expenditures.

Condition data is gathered through asset inspection and maintenance activities and is used along with defect, failure and performance data to formulate asset management strategies. Condition assessment relies on asset knowledge capable of being modelled using numerical analysis.

A number of observations were concluded as part of the review including the need to obtain condition data consistently across all asset types and in electronic form. The need for storage and collection would align with other business initiatives such as the AJILIS project.

5 Description of the Assets

High voltage (HV) switchgear performs a critical function in the reliable operation of the transmission system, connecting substations to the distribution network and in some cases directly to major industrial customers. TasNetworks has high voltage systems operating at 44, 33, 22, 11 and 6.6 kV. The predominant operating voltages are 22 and 11 kV.

HV switchgear includes circuit breakers, disconnectors, earthing switches, instrument transformers, supporting structures, cubicles and cable terminations. HV switchgear falls into two broad categories – outdoor type and indoor type where indoor type mainly consists of metal-clad switchgear. There are 15 outdoor and 578 indoor switchbays currently in service.

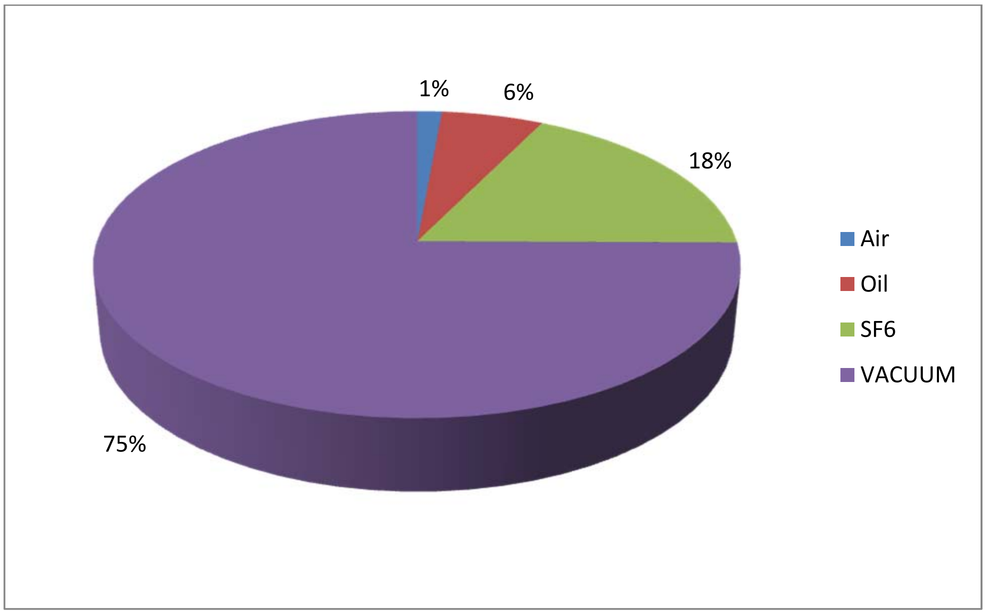
5.1 HV Switchgear Type

TasNetworks HV switchgear can be categorised based on the insulating medium used. The categories include:

- Air (8 switchbays)
- Oil (33 switchbays)
- Sulphur Hexafluoride gas (SF6) (100 switchbays)
- Vacuum (420 switchbays)

The population of HV switchgear includes units constructed by 13 different manufacturers comprising 46 different types. Condition monitoring results for each of the types can vary as different design and construction methods are used for each type. The differences in physical design and construction characteristics between types, increases the complexity of contingency planning and spares management. Figure 6 illustrates the percentage of each type of switchgear within the population, which also indicates that around 93 per cent of TasNetworks HV switchgear population comprises either vacuum or SF6 insulated switchgear.

Figure 6: High voltage switchgear population by type of insulant

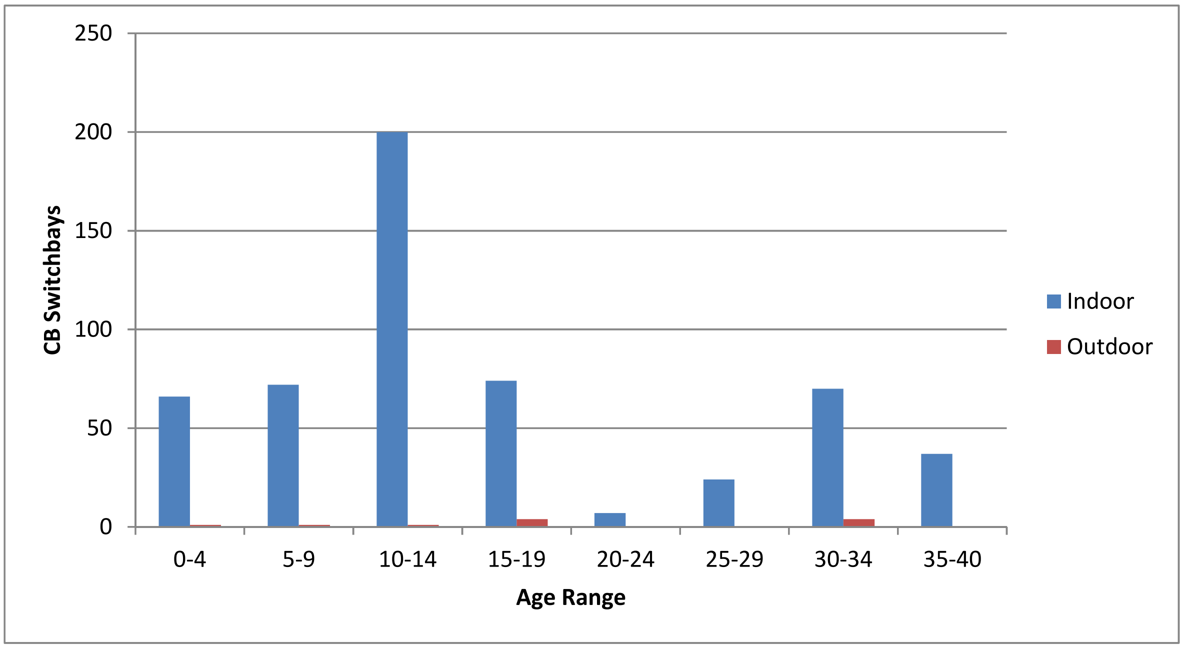


5.2 Age Profile

HV switchgear is considered to have an average service life of 45 years. The average age of TasNetworks' indoor and outdoor HV switchgear population is 15.9 years and 20.6 years respectively as at 2017. The overall average age of the entire HV switchgear population is 16 years. This relatively low average age profile is largely as a result of TasNetworks' HV switchgear replacement program, which has resulted in many of the outdoor installations replaced with modern indoor metal-clad switchgear and the establishment of new connection sites.

Given the relatively low average age of TasNetworks' HV switchgear, overall performance levels of the population should not be adversely affected by age-related issues. The age profile (from manufacture) for TasNetworks HV switchgear population is shown in Figure 7.

Figure 7: Age profile of high voltage switchgear (as at October 2017)



6 Standard of Service

6.1 Technical Standards

To address potential design issues, TasNetworks has developed a comprehensive, prescriptive standard specification for the purchase of new HV switchgear units. The specification requires new units to be designed and type-tested to Australian and international standards. It is also a requirement that HV switchgear have a history of proven service within Australia for at least three years. TasNetworks' current design requirements for HV switchgear are specified in High Voltage System Standard. The standard requires HV switchgear to be of indoor type. Compared to outdoor switchgear, indoor switchgear is compact, more reliable, has minimum interaction with environment (weather, wild life, vegetation, etc.) and is easier to operate and maintain.

Some of the most important design principles relating to HV switchgear are on the specific requirements for circuit breakers. While they must be of indoor construction and housed within a HV switchboard, TasNetworks' standard in general requires the circuit breakers to use vacuum interrupters, be of withdrawable type, mounted in a compartment to allow racking in and out and be capable of three-phase auto-reclose duty.

Another important aspect of the current design philosophy is on the instrument transformers. The standard requires the current transformers and voltage transformers to be of cast resin type – oil insulated instrument transformers are not accepted.

The HV switchgear Standard specifies the following major functions:

- Circuit breaker;
- Disconnector switch;
- Current transformer;
- Voltage transformer;
- Earth switch;
- Fuse switch;

The full requirements for HV switchgear are specified in the High Voltage System Standard document R565983.

6.2 Performance Objectives

To mitigate the risk of inadequate quality control during manufacturing, TasNetworks requires HV switchgear manufacturers to have AS/NZ ISO 9001 accreditation and conform to its requirements. TasNetworks also requires routine tests to be performed on each HV switchgear unit to prove the quality of manufacture prior to dispatch from the manufacturer's works.

6.3 Key Performance Indicators

6.3.1 Internal Performance Monitoring

TasNetworks monitors HV switchgear performance for major faults through its incident reporting process. The process involves the creation of a fault incident record in the event of a major HV switchgear failure that has an immediate impact on the transmission system (eg causes an immediate trip of a transmission circuit or element). The fault is then subjected to a detailed investigation that establishes the root cause of the failure and recommends remedial strategies to reduce the likelihood of recurrence of the failure mode within the HV switchgear population. Reference to individual fault investigation reports can be found in TasNetworks' reliability incident management system (RIMSys).

For HV switchgear failures that do not initiate a transmission system event, such as minor failure or defects, TasNetworks has recently developed a defects management system that enables internal performance monitoring of all HV switchgear-related faults or defects.

6.3.2 External Performance Monitoring

TasNetworks participates in various benchmarking forums to benchmark asset management practices against international and national transmission companies. Key benchmarking forums include:

- International Transmission Operations & Maintenance Study (ITOMS); and
- Australian and New Zealand chief executive officer's benchmarking forum, which provides information to the Energy Supply Association of Australia (ESAA) for its annual industry performance report.

Of these, ITOMS does not directly involve benchmarking HV switchgear. TasNetworks also works closely with transmission companies in other key industry forums, such as the International Council on Large Electric Systems (CIGRE), to compare asset management practices and performance.

CIGRE considers collecting, analysing, and publishing reliability data. Deregulation and new technologies have caused the service and maintenance practices to change and therefore CIGRE SC-13 in 2003 established WG A3.06 ‘Reliability of high voltage equipment’ to organize and carryout a new worldwide enquiry on service experience on high voltage equipment.

7 Associated Risk

7.1 Risk Management Framework

TasNetworks has developed a Risk Management Framework for the purposes of assessing and managing its business risks, and for ensuring a consistent and structured approach for the management of risk is applied.

The Risk Management Framework requires that each risk event is assessed against all of the following consequence categories:

- Safety and People
- Financial
- Customer
- Regulatory Compliance
- Network Performance
- Reputation
- Environment and Community

An assessment of the risks associated with the HV switchgears has been undertaken in accordance with the Risk Management Framework. For each asset in this class the assessments have been made based on:

- Condition of HV switchgears in service across the network
- Criticality of HV switchgears and associated assets
- Probability of failure (not meeting business requirement)
- Consequence of failure
- Performance
- Safety risk
- Environmental risk
- Customer

The quantification of risk is supported by the Condition Based Risk Management (CBRM) framework. This approach allows the risks of individual assets to be quantified against the defined assessment.

Due to the level of risk identified in some of the assessment criteria a requirement to actively manage these risks has been identified.

7.1.1 Condition

The condition assessment and maintenance practices for HV switchgear have been revised where appropriate to sustain or improve the reliability and optimise transmission system performance and to maintain TasNetworks' business risk to within acceptable levels. Such maintenance methodologies, combined with best practices and industry benchmarking activities, are aimed at reinforcing and implementing a regime of continual improvement, innovation and learning. The adoption of contemporary asset management techniques, including Sulphur Hexafluoride (SF6) gas analysis and the implementation of on-line monitoring where practical, are aimed at reducing HV switchgear average annual preventive maintenance expenditure. The improved preventive maintenance practices will also enhance transmission circuit availability, resulting in improved service levels to all customers.

A variety of condition assessment methods are used to determine HV switchgear electrical and operational condition. The methods include:

- Electrical testing including insulation and contact resistance measurement;
- Infra-red thermography
- Mechanism timing test
- Sulphur Hexafluoride (SF6) gas pressure monitoring;
- Partial discharge measurements; and
- Online monitoring of fault operations (proposed)
- Health index
    - The average defect age
    - Manufacturer support
    - Spares availability
    - Maintenance complexity
    - Functionality complexity

The asset condition based health index factors have been identified as:

7.1.1.1 The Average Defect Age

The average defect age for an asset category model is calculated from the defects recorded in the asset management information system. The average defect age is compared to the asset age and as the asset approaches the average defect age it has an increased influence on the health index. The average defect age should indicate the upward trend of the 'bathtub curve' for the asset category model. In order to eliminate defects from the start of the bathtub curve, defects recorded within the asset warranty period are omitted. Where there are no defects recorded for a model, the average defect age is the manufacturers design life.

7.1.1.2 Manufacturer Support

The factors effecting manufacturer support are the supply of spares, provision of repair services, or availability of local support for the asset category model. These factors combine to determine the level of obsolescence and are used toward the health index calculation.

7.1.1.3 Spares Availability

TasNetworks' spares policy for a particular asset category is reviewed and is a factor towards the health index calculation.

7.1.1.4 Maintenance Complexity

The factors determining maintenance complexity are the limited knowledge and skills to maintain the asset category model. This complexity shall increase the health index as human error can contribute to the failure of an asset category model.

7.1.1.5 Functionality

The lack of functionality of older asset category assets is deemed as a contributor to poor condition as improvements in technology leading to an increase in functionality is generally in aid of decreasing operating costs

Details of the above condition assessment methods are included in Appendix B- Condition Assessment Methodologies.

HV switchgear electrical and operational condition is determined using a combination of the above condition monitoring methods, which are selected depending on the design and construction principle of specific types of switchgear. For example, outdoor switchgear constructed using different design and construction principles than indoor switchgear, results in different failure modes and hence need different condition assessment methods. The combination of test methods enables a collective and thorough approach to determine the condition of the HV switchgear population.

7.1.1.6 High voltage indoor switchgear condition summary

A detailed assessment of the electrical condition of indoor HV switchgear population has identified that all units are generally in acceptable electrical condition except the ones that have been specified in the corresponding sections (refer Appendix C - Metalclad Switchgear Condition Assessment). Most the population of HV indoor switchgear is below an age of 32 years and are not expected to present significant issues in the short to medium term although these older installations do not have internal arc fault containment (IAC) features. Sites which have indoor HV switchgear exceeding 32 years of age and have no IAC.

They are:

- Merlin Gerin Type DSC46 Air insulated at Emu Bay Substation;
- GEC Australia Type OLX3 oil insulated at North Hobart Substation.

7.1.1.7 High voltage outdoor switchgear condition summary

Currently there are 4 sites with outdoor switchgear, namely Arthurs Lake, Derwent Bridge, Que, and Rosebery substations. A detailed assessment of the electrical condition of outdoor high voltage switchgear population is provided in Appendix D – Outdoor HV Switchgear Condition Assessment. The first two sites have only one circuit breaker at each site while Rosebery Substation has nine. Apart from the circuit breakers these sites have other outdoor equipment; disconnectors, current transformers and voltage transformers.

Condition monitoring results for the population indicate that:

- The 22 kV current transformers at Que Substation are in poor electrical condition. Low level partial discharge was detected in the 22 kV A552 circuit breaker; and
- The 22 kV NU-LEC circuit breaker type N27 ACR SF6 at Derwent Bridge Substation has shown high partial discharge readings on the associated cable and it has a cracked insulator.
- The 44 kV switchgear at Rosebery Substation has exhibited on-going SF6 gas leaks which are proving difficult to address. These units have been targeted for replacement due to condition and poor reliability.
- The rest of the outdoor switchgear is generally in an acceptable electrical condition.

7.1.2 Criticality

The criticality factor is based on the primary circuit that the asset category asset is part of. These values are recorded within the AMIS and are used by both the secondary risk calculation and the CBRM tool.

7.1.3 Probability of Failure

The probability of failure is directly related to the health index. As with the CBRM tool, engineering experience is used to apply uniform weighting factors to the formula to ensure an accurate result is achieved in line with the current condition of the asset population.

7.1.4 Consequence of Failure

The consequence of failure takes in the circuit criticality and other cost factors associated with the circuit such as value of lost load, maintenance costs, equipment replacement costs etc. If these values are not able to be put into the risk method it needs to be included in capital expenditure analysis in the form of a net present value calculation.

The main risks associated with the HV switchgear population include:

- Major asset failure;
- Environmental issues; and
- Safety issues (eg substandard clearances)

To reduce the risk of a HV switchgear failure, TasNetworks has adopted the following specific strategies to address the predominant causes and consequences of failure.

In the late 1990s, an increasing number of explosive high voltage (HV) switchgear failures, which had a considerable impact on the reliability of electricity supply and presented a significant safety risk to employees, contractors, and in some cases, the public occurred. It was subsequently identified that a significant proportion of the HV switchgear population was very unreliable, was in poor condition and presented significant safety risks. To improve the reliability of electricity supply and to address the identified performance issues, in 1997, a program to replace poor performing HV switchgear was established. This replacement program has progressed largely as planned, with the HV switchgear being replaced at 20 substations, of which 13 were commissioned in the 2004–2009 regulatory control period

7.1.5 Environmental Risk

TasNetworks' main environmental risks associated with HV switchgear relate to the insulating medium used within the units. Currently only 32 per cent of TasNetworks' HV switchgear population has oil or SF_6 as the insulating medium (14 per cent Oil and 18 per cent SF6). As HV switchgear uses low volumes of insulating oil or SF_6 gas relative to other electrical equipment, the risk to the environment is minimal. The risks include:

- Management of polychlorinated biphenyls (PCBs) associated with oil-filled units;
- Management of SF_6 gas associated with gas-filled units;
- Mitigation of wildlife incidents; and
- Prolonged exposure to harsh climatic conditions can result in performance degradation of the switchgear.

7.1.6 Safety Risk

The safety issues associated with TasNetworks' HV switchgear relate mainly to installations which have substandard clearances such as Arthurs Lake Substation and lack of arc fault containment feature at a number of sites. All new indoor switchgears have been fitted with the internal arc containment features to make them safe to operate and maintain.

The older switchgears that don't have the internal arc containment capability can potentially impose arc flash hazard. Type tested internal arc retrofits are available for some of the switchgears such as Reyrolle LMT installed at Bridgewater, Kingston, and Rokeby substations. Another safety concern is the possibility of an explosive failure. This risk can be minimised by replacement of the oil type circuit breakers with type tested vacuum circuit breaker retrofits which is occurring at Rokeby, Bridgewater and Kingston Substations with expected completion in 2017.

Further details on TasNetworks' Arc Flash Risk Management Assessment can be found here R152836.

7.2 Failures Summary

TasNetworks has experienced outages caused by HV switchgear major failures. Failures up to 2008 are shown in Table 1. Failure information is not readily available post 2008 due to lack of recorded data. As data becomes available it will be added to future amendment o this AMP which should be enhanced with the implementation of new SAP system due for release in 2018.

Table 1: Major failures associated with HV switchgear

Date	Substation	Voltage	Make of Switchgear	Cause/nature of failure	System mins lost
18-Mar-2000	Derby	22 kV		Feeder 1 failed to trip on earth fault due to failed trip coil	Not captured
16-Feb-2002	Sorell	22 kV	Brown Boveri	Bus flashover in the joggle chamber, attributed to presence of ozone due to partial discharges	Not captured
24-Sep-2003	Scottsdale	22 kV		A252 latching mechanism failure	Not captured
29-Sep-2003	Burnie	22 kV		Bus coupler CT exploded	Not captured
12-Aug-2004	Scottsdale	22 kV		A252 damaged circuit breaker	Not captured
8-Dec-2005	Port Latta	22 kV	Yorkshire	Circuit breaker A252 failed to close after a fault. The limit switch assembly controlling the spring rewind motor was found to be faulty. These CBs (Yorkshire type IV10-16-MK2/800) are now replaced	0.13
8-Apr-2006	George Town	22 kV	Siemens	CB E252 vacuum canister failure	Refer to IR270 for full report and system minutes lost
21-Jan-2007	Sorell	22 kV	Brown Boveri	D252 CB flashover, attributed to presence of ozone due to partial discharges	0.45
14-Apr-2007	Mowbray	22 kV	Siemens	22 kV bus coupler circuit breaker (C852) - 'A' Bus blue phase CT failed catastrophically	0.79
6-Dec-2007	Sorell	22 kV	Brown Boveri	Flashover in A252 CB cubicle,	0.26

				inconclusive evidence to determine the cause of failure	
7-Apr-2008	Que	22 kV	Sadtem	22 kV CT B296B failed during a feeder earth fault	0.82
23-May-2008	Sorell	22 kV	Brown Boveri	22 kV B552 CB tripped	?????

Of the sites mentioned above, switchgear at Port Latta and Sorell substations are targeted for replacement in the coming regulatory period.

7.3 Special Operational and Design Issues

7.3.1 Operational Issues

There are currently no specific capacity issues with the HV switchgear population.

7.3.2 Specific Design Issues

There are design and compliance issues specific to certain manufacture and model type of HV switchgear. These design and compliance considerations, grouped by manufacturer and type, are assessed in detail in Appendices D and E.

Some of the issues identified on specific types of switchgear or sites include:

- Presence of maintenance intensive oil filled switchgear in the HV switchgear population (6 per cent of the total population);
- Design issues associated with specific HV switchgear types, including the following:
    - In Brown Boveri type BA1-HB 22 kV circuit breakers installed at Sorell, Railton and Ulverstone substations, contactor heat sinks interact with busbar shutters during the rack-in process causing shutter damage and partial discharges; and
    - High level of surface discharge activity and smell of Ozone was detected on all three bus coupler circuit breakers type ORTHOFLUOR FPX of the GEC-Alstom 22kV metal-clad switchgear installed at Trevallyn Substation (switchboard type Normaclad PX24). The presence of PD activity within bus coupler units is due to poor design and inadequate clearance between the circuit breaker bushings.
    - Lack of internal arc fault containment in older installations
- Difficulties in getting spare parts for obsolete switchgear as they are no longer supported by manufacturers; and
- Lack of standardisation throughout the HV switchgear population, which includes units constructed by 13 manufacturers comprising 46 different types. (Recent steps taken towards standardisation have reduced the diversity by containing 50 per cent of the switchgear to three manufacturers).

7.4 Summary of Risk

HV switchgear must be selected to provide reliable service for its expected 45 years life. Some of the issues identified on specific types of switchgear or sites include:

a. Presence of maintenance intensive oil filled switchgear in the HV switchgear population (6 per cent of the total population)[1];
b. Design issues associated with specific HV switchgear types, including the following:
   i High level of surface discharge activity and smell of Ozone was detected on all three bus coupler circuit breakers type ORTHOFLUOR FPX of the GEC-Alstom 22kV metal-clad switchgear installed at the Trevallyn (switchboard type Normaclad PX24). The presence of PD activity within bus coupler units is due to poor design and inadequate clearance between the CB bushings; and
   ii In Brown Boveri type BA1–HB 22 kV circuit breakers, contactor heat sinks interact with busbar shutters during the rack-in process causing shutter damage and partial discharges.
   iii Lack of internal arc fault containment in older installations.
c. Difficulties in getting spare parts for obsolete switchgear as they are no longer supported by manufacturers; and
d. Lack of standardisation throughout the HV switchgear population, which includes units constructed by 14 manufacturers comprising 22 different types. (Recent steps taken towards standardisation have reduced the diversity by containing 50 per cent of the switchgear to three manufacturers).

[1] Note was 14% at start of 2017. With Removal of 11 kV LMT switchgear from Rokeby, Bridgewater and Kingston Substations has reduced this percentage to 6%.

8 Management Plan

8.1 Historical

Historically, management of HV circuit breakers has been undertaken based primarily on condition and condition assessments. This will be continued into the future through inclusion of a Condition Based Risk Management (CBRM) program which aligns with direction provided in TasNetworks Strategic Asset management Plan (SAMP). Figure 14 provides an overview as to which management techniques are applied by TasNetworks in managing the risks of each asset category in our asset base as detailed in the SAMP.

Figure 8 – TasNetworks asset category management overview

How are assets managed?																		
Assets	Past						Present						Future					
	Run to failure	Subject Matter Expert (SME)	Time based (Age)	Reliability centered maintenance (RCM)	Condition based	CBRM	Run to failure	Subject Matter Expert (SME)	Time based (Age)	Reliability centered maintenance (RCM)	Condition based	CBRM	Run to failure	Subject Matter Expert (SME)	Time based (Age)	Reliability centered maintenance (RCM)	Condition based	CBRM
Substations																		
Transformers (power)			✓						✓ (maintenance)		✓	✓ (renewed)			✓			✓
EHV circuit breakers			✓						✓ (maintenance)			✓ (renewed)			✓			✓
HV circuit breakers			✓						✓ (maintenance)			✓ (renewed)			✓			✓
EHV Disconnectors & Earth switches			✓						✓ (maintenance)			✓ (renewed)			✓			✓
EHV CT's			✓						✓ (maintenance)			✓ (renewed)					✓	✓
EHV VT's			✓						✓ (maintenance)			✓ (renewed)					✓	✓
Power cables			✓						✓ (maintenance)		✓	✓ (renewed)					✓	✓
Site infrastructure					✓						✓						✓	✓

8.2 Strategy

The management strategies adopted to mitigate the risks associated with HV switchgear are monitored on an ongoing basis to ensure they are effective and relevant to achieving TasNetworks' risk management objectives. Practices are reviewed on a regular basis taking into account:

- Past performance;
- Manufacturer's recommendations;
- Industry practice (derived from participation in technical forums, benchmarking exercises and discussions with other transmission companies); and
- Availability of new technology.

Failures within HV switchgear may cause serious or catastrophic damage to the assets, so allowing failures to occur represents a real risk to the surrounding infrastructure.

To reduce the risk of HV switchgear failure, TasNetworks has adopted the following specific strategies to address the predominant causes and consequences of failure.

8.2.1 Routine Maintenance

There is a fundamental requirement for TasNetworks 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.

8.2.2 Routine Maintenance versus Non Routine Maintenance

Failures within HV switchgear may cause serious or catastrophic damage to the asset. These assets are located in critical network points, so allowing failures to occur represents a real risk to the supply reliability of the electrical system. 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.

8.2.3 Refurbishment

Where HV switchgears 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. These assets can also be included in the pool of spare management.

8.2.4 Planned Asset Replacement versus Reactive Asset Replacement

Replacement is generally only preferred when this is a more economic proposition compared 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. Reactive replacements are generally several times more expensive, incurring overtime, call out penalties and additional repair costs to cable terminations and nearby infrastructure

Some corrective works have been recommended in the PD survey reports by EA Technology UK to reduce or eliminate the partial discharge activities within the HV switchboards. The implementation of these recommendations will improve the condition and performance of these switchboards.

8.2.5 Non Network Solutions

The role of the high voltage switchgear generally cannot be cost effectively substituted via upgrading other infrastructure on the network.

8.2.6 Network Augmentation Impacts

TasNetworks' requirements for developing the power transmission system are principally driven by five elements:

1. Demand forecasts;
2. New customer connection requests;
3. New generation requests;
4. Network performance requirements; and
5. National electricity rules (NER) compliance.

Details of planned network augmentation works can be found in TasNetworks' Regional Development Plan, which are updated on an annual basis.

Proposed network augmentation projects identified in the Regional Development Plan will have a minimal impact on the HV switchgear population from an asset management perspective. Additional costs associated with new HV switchgear installations as part of network augmentation projects will increase the impact on the ten-year projected operational expenditure detailed in Section 9.1 of this plan

8.3 Routine Maintenance

The performance of HV switchgear is sustained by the implementation of regular condition monitoring and preventive maintenance activities. Maintenance practices are reviewed on a regular basis taking into account:

- Past performance
- Manufacturer's recommendations;
- Industry practice (derived from participation in technical forums, benchmarking exercises and discussions with other transmission and distribution companies); and
- The availability of new technology.

Previous preventive maintenance practices included maintenance of HV switchgear on a six yearly basis irrespective of its type or age. As modern vacuum switchgear needs less maintenance, this practice has been reviewed. Condition assessment methods as detailed in Appendix B- Condition Assessment Methodologies will now be used to determine HV switchgear electrical condition.

The revised condition assessment and maintenance practices for all types of HV switchgears are shown in Table 3 . Based on condition monitoring data, the frequency of maintenance may increase towards the end of switchgear's life. In the event that increased maintenance is required, the decision to replace the switchgear may be justified depending on the impact on preventive maintenance expenditure and transmission system performance.

8.3.1 Partial Discharge Monitoring program

Partial discharge (PD) measurements provide a powerful technique to diagnose the condition on insulation in high voltage equipment. After several fault incidents on HV switchgear which could be attributed to partial discharges (PD), there has been increased concern to detect and prevent excessive PD from occurring. Some measures have already been taken to control partial discharges by installing air conditioners and improving sealing of switchgear rooms at Sorell and Ulverstone substations. However, there still are concerns that partial discharge activity has not stopped completely at these sites. Also there could be other sites where partial discharge is occurring undetected.

Partial discharge measurements provide a means of assessing the condition or health of insulation of the installation. PD measurements can either be carried out periodically in conjunction with the substation inspection program using portable equipment or with devices permanently mounted on the switchgear for online monitoring.

Measurement of PD needs to be initially carried out while the equipment is in service whereas suspected switchgear may require an outage for closer inspection. Other measures which prevent or reduce the occurrence of PD can also be taken at substations where such measures are absent. These may include installation of heaters and/or air conditioners, hermetically sealing of buildings to prevent moisture ingress etc.

Portable hand held equipment is currently used at TasNetworks to test individual bays in-turn and has provided some confidence in the condition of assets. This partial discharge measuring/monitoring program is expected to continue.

There has recently been purchased PD monitoring device (relocatable unit) that can be installed in a switchroom and covers the whole installation. Installations without internal arc fault containment or where high PD levels have been detected with the use of the hand held PD test will be considered for initial installation of this whole of room monitoring equipment. The technical merits and any other benefits from such installations will continue to be assessed against the additional capital expenditure.

TasNetworks commissioned an external PD survey of all HV switchgear installations originally in 2010 with follow up PD testing in 2012, 2014 and 2016. An analysis of the results identified that a number of sites had isolated areas of high PD discharge and as a consequence these findings have prompted a change to TasNetworks' PD monitoring practice in an endeavour to proactively manage latent defects. The previous PD measurement maintenance practice, scheduled to be performed every 3 years, has now been amended and now states that PD audits must be performed every two years. It is also recommended that scheduled audits (performed by an approved external service provider) be supplemented every 6 months by an internal audit for those installations that have been identified with suspect PD measurements. The equipment utilised by the service provider must be the same as the measurement instrumentation purchased by TasNetworks, namely the 'UltraTEV+ Kit 3' PD detection devices, to ensure that there is consistency in the measurements taken for asset management and defect trending purposes.

The PD survey and benchmarking activities initiated in 2010 has provided evidence that PD portable equipment and technology has advance to where there is a higher degree of accuracy over previous methods of PD detection. TasNetworks has therefore purchased the 'UltraTEV+ Kit3' PD detection devices and adopted a maintenance practice based on the use of this equipment as the preferred method for non-intrusive PD testing.

Where PD levels have been detected, follow-up actions may be instituted pending a detailed engineering assessment. This assessment may in turn lead to an increase in various monitoring practices and/or other interventions as deemed necessary. The following PD measurement thresholds can be used as a guideline to categorise the severity of the PD activity:

- Condition 'Red' means PD > 30 dB;
- Condition 'Amber' means 20 dB < PD < 29 dB; and
- Condition 'Green' means PD < 20 db.

8.3.2 Online monitoring of circuit breaker fault operations

To ensure optimal performance of a circuit breaker, it is necessary to make sure that the interrupting capability is maintained at its optimum level at all times and has not been compromised due to fault operations. A maintenance regime based only on a fixed time interval does not necessarily guarantee the optimum condition of the switchgear. Such schemes could lead to excessive maintenance if there have been no fault operations during that period or leave the contacts in a deteriorated condition for an extended period if there were a large number of fault operations and the maintenance interval is too long.

Modern protection relays (Alstom MiCom P143 and Siemens 7SJ64) are capable of recording various statistics related to each circuit breaker fault operation allowing a more accurate assessment of the circuit breaker condition to be made. The relay is equipped with condition monitoring counters which are updated every time the relay issues a trip command. One such counter monitors the cumulative fault current interrupted by the contacts giving a more accurate assessment of the severity of the duty placed on the interrupter. These facilities could be used to achieve a condition based maintenance regime for HV switchgear.

A monitoring regime could first be implemented at selected sites before a full rollout.

8.3.3 Environmental related programs

To reduce the environmental risks associated with HV switchgear, TasNetworks has adopted the following specific strategies.

8.3.3.1 PCB testing program

To mitigate the risks associated with PCB contamination, TasNetworks has implemented a program to determine the PCB levels within the HV switchgear population where practicable. The following six sites shown in Table 2 have switchgear with oil as the insulant. All sites with oil insulated switchgear have been tested.

Table 2: PCB levels in oil insulated switchgear

Site	Switchgear Type	PCB content
North Hobart	GEC Australia	< 2.0 ppm
Norwood	Sprecher & Schuh	< 2.0 ppm
Rosebery	Sprecher & Schuh	< 2.0 ppm

As can be seen from Table 2, of the units that have been tested to date, all have been verified as PCB-free.

8.3.3.2 SF6 management

To mitigate the risk of loss of SF6 gas to the atmosphere, TasNetworks has developed a comprehensive procedure for the management of SF6 gas, which is detailed in document TNM-PC-809-0094 Sulphur Hexafluoride Gas Management Procedure.

8.3.4 Summary of Maintenance programs

Table 3: Condition monitoring and preventive maintenance practices

Task	Frequency (based on medium of Insulation)			
	Vacuum	SF_6	Oil	Air
Visual inspections and routine condition monitoring coordinated with substation inspection program	Quarterly	Quarterly	Quarterly	Quarterly
Electrical testing (insulation resistance, contact resistance, etc.)	18 years after commissioning and every six years thereafter	18 years after commissioning and every six years thereafter	Every 3 years	Every 3 years
Monitoring of SF_6 gas pressure	n/a	Continuously	n/a	n/a
Partial discharge measurements*	Biennially	Biennially	Biennially	Biennially
Online monitoring of circuit breaker fault operations (only modern switchgear)	Continuously	Continuously	Continuously	Continuously

* see implementation note in Section 8.3.1

8.4 Non Routine Maintenance

Minor and major asset defects that are specifically identified during asset inspections and routine maintenance or through other ad-hoc site visits are prioritised and rectified as per the recommendations set out in TasNetworks condition assessment report and general asset defects management process.

The methodology used to develop and manage non routine maintenance is adjusted to meet the option analysis completed specific for the defect to meet the performance criteria set out in TasNetworks' risk framework, with the objective to return to service and prevent asset failure.

8.5 Reliability and Quality Maintained

8.5.1 Standardisation

There are a number of different HV switchgear makes and models installed throughout TasNetworks' sites. Installations that are unique and dissimilar to the remainder of the fleet are difficult to maintain, since lack of familiarity with the equipment increases the effort required to maintain them.

TasNetworks is actively seeking to standardise on a smaller number of HV switchgear models to reduce the overheads associated with maintaining a diverse range of equipment. Other models may be accepted where these models have been used within the wider TasNetworks network and spares are already available, however, the exact same model of device will be specified so as to maintain acceptable numbers of spares.

To mitigate the risks associated with a major failure of HV switchgear, TasNetworks has standardised on the use of vacuum type indoor HV switchgear for new or replacement installations. While the failure rates for all types of indoor switchgear are relatively low, TasNetworks' preference is to use vacuum type switchgear for the additional benefit of minimised environmental impacts. The standardisation of HV switchgear also addresses population issues identified in section 8.9 in the long term. One major advantage of the standardisation is the lessened burden on spares management.

8.5.2 Contingency planning

To mitigate the risk of inadequate response in the event of a HV switchgear failure, TasNetworks has developed a contingency plan to minimise the impact on the reliability and availability of electricity supply in the event of a HV switchgear failure. Contingency planning considerations specific to HV switchgear are documented in TNM-PL-809-0553 Substation Primary Equipment Contingency Plan.

8.6 Regulatory Obligations

8.6.1 Service Obligations for Network Assets

HV switchgear performance impacts on TasNetworks' overall network service obligations, which include specific performance requirements for both regulated and connection transmission assets.

TasNetworks' Service Target Performance Incentive (STPIS) scheme, which has been produced in accordance with the Australian Energy Regulator's (AER's) Service Standards Guideline, is based on plant and supply availability. The incentive scheme includes the following specific measures:

- Plant availability:

- Transmission line circuit availability (critical and non-critical); and
- Transformer circuit availability.

- Supply availability:
  - Number of events in which loss of supply exceeds 0.1 system minute; and
  - Number of events in which loss of supply exceeds 1.0 system minutes.

Details of the STIPIS scheme and performance targets are managed by TasNetworks Asset Performance group and are listed in TasNetworks Corporate and Business plans.

There are currently no specific service level obligations for HV switchgear but they do have an impact on transformer circuit availability.

8.6.2 Service Obligations for Non-regulated Assets

8.6.2.1 Hydro Tasmania

TasNetworks has a Performance Incentive (PI) scheme in place with Hydro Tasmania under its Connection and Network Service Agreement (CANS 2) for connection assets between the two companies. The PI scheme includes the connection asset availability measure.

An overview of Hydro Tasmania PI scheme and performance targets can be found in the associated connection agreement.

8.6.2.2 Tamar Valley Power Station (TVPS)

TasNetworks has a PI scheme in place with TVPS under its Generator Connection Agreement for connection assets between the two companies. The PI scheme includes the connection asset availability measure. An overview of TVPS PI scheme and performance targets can be found in the associated Connection Agreement.

8.6.2.3 Major Industrial direct customer connections

TasNetworks have a number of direct connections to major industrial customers through EHV and HV substations. The following sites have asset category assets providing these direct connections:

- Boyer Substation (6.6 kV);
- George Town Substation (220 kV & 110 kV);
- Huon River Substation (11 kV);
- Newton Substation (22 kV);
- Port Latta Substation (22 kV);
- Que Substation (22 kV);
- Queenstown Substation (11 kV);
- Risdon Substation (11 kV);
- Rosebery Substation (44 kV); and
- Savage River Substation (22 kV);

The individual connection agreements describe the level of service and performance obligations required from the associated connection assets.

8.7 Replacement

Where a complete new switchboard to be installed, the opportunity exists to consider whether direct replacement is necessary or whether the switchboard arrangement can be simplified. It may take into account the capacity uprating and also benefits of reduced maintenance costs associated with the new switchgear.

It will generally provide the opportunity to modernise the protection and control schemes.

Modern switchgear will generally require less space which may necessitate the relocation of the existing feeder cables. It is therefore important to be aware that old paper / lead cables can be internally damaged by significant disturbance / movement. Appropriate measures need to be taken to avoid this.

8.7.1 HV Switchgear Replacement/ Refurbished / Retrofitted Program

To address design, condition, safety and performance risks associated with the HV switchgear population, continuation of the HV switchgear replacement program is recommended. This replacement targets those installations with oil insulated switchgear and/or without internal arc fault containment (IAC). The HV switchgear replacements will, where appropriate be coordinated with the respective substation redevelopment projects and each project will be individually justified with supporting information prepared as appropriate.

The retrofit / replacement approach can be taken to address problems caused by inadequate rating, inadequate operating mechanism or arc interruption system, or deteriorated / defective insulation. After an overall assessment of the parts of the switchgear to be retained a refurbished / retrofitted switchgear program may be considered. The retained parts must have adequate rating and sufficient remaining life to justify the expenditure on refurbishment / retrofitting.

The new metalclad indoor switchgears are compliant with the requirements of AS 62271-200 ‘AC metal-enclosed switchgear and control-gear for rated voltages above 1 kV and up to and including 52 kV’.

Where retrofitting is considered for the existing switchgears, it must be type tested and be complaint with the requirements of the above mentioned Australian standard, before being accepted.

The refurbishment of switchgear can be viewed as a major overhaul of the switchgear with replacement of parts reaching their suggested service due-time, e.g. operating mechanisms, insulation components, seals, etc.

The retrofitting involves updating the existing moving portions of switchgear for use with the existing fixed portions. Particular attention should be paid to the mechanical compatibility between the fixed portion and the new moving portion. Problems can be experienced due to mechanical mismatch between the mating portions, shutter actuation, racking mechanisms and physical clearances. It is prudent to perform a partial discharge survey of the switchboard prior to the installation of the retrofit units, to establish the integrity of the existing equipment and repeat the survey after installation to ensure that problems haven’t been exacerbated or introduced.

The retrofit options may include:

- Replacing the complete circuit breaker truck; or
- Modifying the existing truck to incorporate a vacuum / SF6 (in special cases only) interrupters

A list of the proposed replacement projects for the period 2019 to 2029 is listed in section 8.12.

8.8 Program Delivery

The needs assessment and options analysis for undertaking an asset management activity is documented in the Investment Evaluation Summary for that activity.

The delivery of these activities follows TasNetworks' end to end (E2E) works delivery process.

8.9 Spares Management

As per TasNetworks' Networks System spares policy as a minimum the following should be available at all times:

- One complete circuit breaker of each type;
- Three current transformer of each type;
- Three voltage transformer of each type.

This list acts as a base-line minimum over and above the recommendations by the manufacturer.

Where equipment is common among several installations, it is not necessary to hold the minimum for each substation but a policy of an additional 0.5 times the recommended spares should be kept. This means the full quantity for the first installation and an additional half of that number for each.

A list of TasNetworks' spare indoor and outdoor HV switchgear units is provided in Appendix E

8.10 Technical Support

Other operational costs which are not able to be classified under the above categories are allocated to technical support. These tasks include:

- System fault analysis and investigation;
- Preparation of asset management plans;
- Standards management;
- Management of the service providers;
- Training;
- Group management; and
- General technical advice.

8.11 Disposal Plan

Prior to disposing of decommissioned HV switchgear, units will be reviewed to determine their suitability as system spare units (in accordance with TasNetworks System Spares Policy document) or redeployment elsewhere in the transmission system.

Disposal of HV switchgear utilising insulating oil or SF6 gas must be done so in accordance with relevant standards and procedures.

8.12 Summary of Programs

Tables 4 and 5 provide a summary of all of the programs/projects described in this management plan.

Table 4: Summary of HV Switchgear OPEX programs / projects

Work Program	Work Category	Work Category	Project/Program
Routine Maintenance	CMCBH	Corrective maintenance	S045-SUBS-Corrective-Circuit Breaker HV
	PMCBH	Preventative maintenance	S429-Circuit Breaker Maintenance HV
	PMCTH	Preventative maintenance	S217-Current Transformer Electrical Tests HV
	PMDEH	Preventative maintenance	S453-Disconnector Maintenance HV

Table 5: Summary of HV Switchgear CAPEX programs / projects

Work Program	Work Category	Project title	Project/Program details
Capital	RENSB	Replace Railton 22kV HV switchgear	Replace 22 kV switchboard with IAC rated units. 2021-22
	RENSB	Replace Sorell 22kV HV switchgear	Replace 22 kV switchboard with IAC rated units. 2021-22
	RENSB	Replace Ulverstone 22kV HV switchgear	Replace 22 kV switchboard with IAC rated units. 2021-22
	RENSB	Replace Knights Road 22kV HV switchgear	Replace 22 kV switchboard with IAC rated units. 2023-24
	RENSB	Replace Chapel St 22kV HV switchgear	Replace 11 kV switchboard with IAC rated units. 2021-23
	RENSB	Replace Boyer6.6kV HV switchgear switchhouse 'A'	Replace 6.6 kV switchboard with IAC rated units 2023-25.
	RENSB	Replace Boyer6.6kV HV switchgear switchhouse 'B'	Replace 6.6 kV switchboard with IAC rated units 2024-26.
	RENSB	Replace Rosebery Substation 44 kV switchgear	Replace 44 kV switchgear. 2019-22.

9 Financial Summary

9.1 Proposed OPEX Expenditure Plan

Requirements for operating expenditure are a function of the defined periodic condition monitoring regimes, defined maintenance requirements and expected minor and major site infrastructure works.

In the event that increased maintenance levels are required, the decision to replace equipment may be justified depending on the impact on preventive maintenance expenditure and transmission system performance.

The developed works plan is held and maintained in the works planning tool in AMIS. It contains details such as planning dates, task types, specific assets and planned costs.

9.2 Proposed CAPEX Expenditure Plan

The capital programs and expenditure identified in this management plan are necessary to manage operational and safety risks and maintain network reliably at an acceptable level. All capital expenditure is prioritised expenditure based on current condition data, field failure rates and prudent risk management.

A comprehensive capital investment plan has been developed to address the identified design and performance issues associated with the HV switchgear population and to improve transmission system performance. The replacement program will mitigate the business risks presented by the existing HV switchgear population and reduce future preventive maintenance costs

9.3 CAPEX – OPEX trade offs

The operating expenditure programs are essential for identifying assets that require replacement for condition-based reasons. There is a positive relationship between these two categories in that regular inspection programs gather continuous condition information of the assets to better target asset replacements and identify any asset trends. Maintenance and repair activities also defer the requirement for capital expenditure and increase the likelihood of the asset operating for as long as possible within the network.

10 Related Standards and Documentation

The following documents have been used either in the development of this management plan, or provide supporting information to it:

TasNetworks documents:

1. System Spares Policy R517373
2. Strategic Asset Management Plan R248812
3. Annual Planning Report 2017 R689487
4. Asset Condition Review – project report June16 FINAL – R503361
5. High Voltage Switchgear Replacement Program, Transend Networks, 2008. D08/96908
6. PD survey of TasNetworks Substations, EA Tech report 2016. R503098
7. Risk Management Assessment – Substation High Voltage Switchgear Arc Hazard Risk Management Assessment R152836

Technical requirements for HV voltage switchgear are detailed in the following standards/specifications:

8. High Voltage System Standard, R565983
9. Sulphur Hexafluoride Gas Management Procedure, Transend Networks, 2005. D10/4141.

Other standards and documents

10. Sinclair Knight Merz, ‘Assessment of Economic Lives for Transend Regulatory Asset Classes’, 2013. R192773
11. Australian Standard AS 1883 ‘Guide to maintenance and supervision of insulating oils in service’, Standards Australia, 1993
12. Australian Standard AS 4360 ‘Risk Management’, Standards Australia, 2004

11 Appendix A – Summary of Programs and Risk

Description	Work Category	Risk Level	Driver	Expenditure Type	Residual Risk
S045-SUBS-Corrective-Circuit Breaker HV	CMCBHE	Medium	Customer Financial Network performance Safety	Opex	Low
S433-Circuit Breaker Maintenance HV	PMCBH	Medium	Customer Financial Network performance Safety	Opex	Low
S217-Current Transformer Electrical Tests HV	PMCTH	Medium	Customer Financial Network performance Safety	Opex	Low
S453-Disconnector Maintenance HV	PMDEH	Medium	Customer Financial Network performance Safety	Opex	Low
Replace Railton 22kV HV switchgear	RENSB	Medium	Customer Financial	Capex	Low
		High	Safety		
Replace Sorell 22kV HV switchgear	RENSB	Medium	Customer Financial	Capex	Low
		High	Safety		
Replace Ulverstone 22kV HV switchgear	RENSB	Medium	Customer Financial	Capex	Low
		High	Safety		
Replace Knights Road 22kV HV switchgear	RENSB	Medium	Customer Financial	Capex	Low
		High	Safety		

Description	Work Category	Risk Level	Driver	Expenditure Type	Residual Risk
Replace Chapel St 22kV HV switchgear	RENSB	Medium	Customer Financial Safety	Capex	Low
		High	Safety		
Replace Boyer6.6kV HV switchgear switchhouse ‘A’	RENSB	Medium	Customer Financial Network performance	Capex	Low
		High	Safety		
Replace Boyer6.6kV HV switchgear switchhouse ‘B’	RENSB	Medium	Customer Financial Network performance	Capex	Low
		High	Safety		
Replace Rosebery Substation 44 kV switchgear	RENSB	Medium	Customer Financial Safety	Capex	Low

12 Appendix B- Condition Assessment Methodologies

A variety of condition assessment methods are available to determine the condition of HV switchgear. The methods include:

- Electrical testing including insulation and contact resistance measurement;
- Thermographic surveys;
- Mechanism timing tests;
- SF6 gas pressure monitoring;
- Partial discharge measurements; and
- Online monitoring of fault operations (proposed).

Electrical testing

Historically, electrical testing has been the prime method for condition assessment of HV switchgear. The high voltage testing process involves measurement of insulation resistance to provide an indication of the quality of the insulation and measurement of contact resistance to assess the quality of the contacts. The electrical testing process is, however, sensitive to the prevailing ambient conditions at the time of test. Conditions such as temperature, humidity, cleanliness of insulation and quality of connections, test equipment and testing procedures all influence test results. The analysis of electrical test data does not warrant specific specialist knowledge but to some extent, is subjective. As a general rule, the insulation resistance value should be in the giga-ohm range and contact resistances should be in the micro-ohm range.

Thermographic surveys

Infra-red techniques use either thermal imaging equipment or non-contact thermometers. The techniques are useful for detecting overheated conductors, hot joints and connections and fuses on open-fronted, LV distribution boards or on LV switchgears where live parts can be safely exposed and remotely scanned. These IR techniques can be used on metal clad switchboards if special glasses are fitted into the compartments and also can detect overheated bushings on connections on open terminal switchgears.

Mechanism timing tests

Many problems in circuit breakers are related to damage or distortion of the metal parts or jamming in the mechanism causing failure to open or close, or slow opening of the circuit breaker. This can be dealt with effectively by incorporating timing tests into the periodic trip tests. The trip profile instruments provide more detailed information of the mechanism performance such as time travel tests, etc.

SF6 gas pressure monitoring

In SF6 gas-insulated switchgear, gas sampling and analysis could be used to determine the switchgear condition. In particular, measurement of the water present within the gas can provide an indication of the likelihood of moisture ingress or internal deterioration of the insulation.

Continuous monitoring of SF6 gas pressure is helpful in early diagnosis of any gas leaks and can also be used as an indicator of moisture ingress. SF6 gas insulated HV switchgear are fitted with gas pressure monitoring devices which continuously monitor gas pressure and gives an alarm if the pressure falls below a set value. A major loss of pressure would lockout the circuit breaker from operation.

Partial discharge measurements

Partial discharge measurements provide a means of assessing the condition or health of insulation of the installation. Partial discharge measurements can either be carried out periodically in conjunction with the substation inspection program using portable equipment or with devices permanently mounted on the switchgear for on-line monitoring.

Measurement of partial discharges needs to be initially carried out while the equipment is in service whereas suspected switchgear may require an outage for closer inspection.

Portable hand held equipment is currently used at TasNetworks to test individual bays in-turn and has provided some confidence in the condition of assets. This partial discharge measuring/monitoring program is expected to continue.

There has recently been purchased PD monitoring device (relocatable unit) that can be installed in a switchroom and covers the whole installation. Installations without internal arc fault containment or where high PD levels have been detected with the use of the hand held PD test will be considered for initial installation of this whole of room monitoring equipment. The technical merits and any other benefits from such installations will continue to be assessed against the additional capital expenditure.

On-line monitoring of circuit breaker fault operations

For optimal performance of a circuit breaker, it is necessary to ensure that the interrupting capability is maintained at its optimum level at all times and has not been compromised due to excessive fault operations. A maintenance regime based only on a fixed time interval does not necessarily guarantee the optimum condition of the switchgear. Such schemes could lead to excessive maintenance if there have been no fault operations during that period or leave the contacts in a deteriorated condition for an extended period if there were a large number of fault operations and the maintenance interval is too long.

Modern protection relays (Alstom MiCom P143 and Siemens 7SJ64) are capable of recording various statistics related to each circuit breaker fault operation allowing a more accurate assessment of the circuit breaker condition to be made. The relay is equipped with condition monitoring counters which are updated every time the relay issues a trip command. One such counter monitors the cumulative fault current interrupted by the contacts giving a more accurate assessment of the severity of the duty placed on the interrupter. These facilities could be used to achieve a condition based maintenance regime for HV switchgear.

These relays can be configured to generate an alarm when the cumulative current interrupted by the contacts exceeds a certain value. The alarm could be made available both locally via the substation supervisory control and data acquisition (SCADA) system and remotely via the Network Operations Control System (NOCS).

13 Appendix C - Metalclad Switchgear Condition Assessment

In this section, indoor metalclad switchgear has been grouped by manufacturer and assessed on two key criteria: electrical and physical condition and design considerations. Based on condition and design issues, future management strategies for each type are determined. Note that the year represents the year of commissioning.

In general, new generation metalclad switchgear is very reliable and requires minimal maintenance. Hence, based on past experience and good industry practice, a new maintenance regime is recommended to be investigated for the new switchgear Alstom, Areva, ABB and Siemens – to maintain them at less frequent intervals. This will replace the current regime of maintaining all switchgear every six years irrespective of the type, make or the condition.

Partial Discharge Survey

Biennial PD testing has been conducted by EA Technology from UK since 2010 with latest results in 2016 see PD survey of TasNetworks Substations, EA Tech report 2016. R503098.

It is recommended that reference is made to the reports and any remedial action required to be reviewed and actioned as necessary cognisant with the risk level identified.

Alstom

Table 6: List of all in service Alstom indoor HV switchgear

Switchgear type	CB type	Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [Years]	Number of units
Normaclad PX24	ORTHOFLUOR /FPX	SF_6	Trevallyn	22	A852 B252 B852 C852 D252 D852 E252 F252 G252 H252 H552 J252 J552 K252 K552 L252 S252 T252 U252	1996 to 2000	17 to 21	23

					V252 W252 X252 Y252			
WS	WSA 6/36-2/623	Vacuum	Creek Road	33	A252 B252 B552 B852 C252 C552 C852 D252 D552 E252 F252 G252 H252 J252 K252 Z252	2002/ 2004	15/13	16
Total number of switch-bays in service								**39**

Condition

Alstom switchgear is installed at two sites. Type Normaclad PX24 using SF6 ORTHOFLUOR / FPX circuit breaker in the air insulated 22 kV switchgear at Trevallyn Substation and type WSA using vacuum circuit breaker in SF6 bus insulated 33 kV switchgear at Creek Road Substation. The PD survey results for the Alstom circuit breakers at Trevallyn Substation have shown high level of surface partial discharge on some bays.

At Creek Road Substation, the 33 kV bus bars are SF6 insulated and hence subject to a different maintenance regime. In 2016, a voltage transformer failed at Creek Road Substation

Design

During 2003–2005 SF6 gas leaks were detected from the pressure sensor in some of the poles of circuit breakers type ORTHOFLUOR / FPX at Trevallyn Substation. The circuit breaker pole had to be frequently topped up to maintain the required pressure. The manufacturer’s representative proposed the poles be sent to their workshop so new pressure sensors could be fitted. The faulty units were repaired in 2005–2006 and the leaks never recurred.

Another issue with this type of switchgear is the location of current transformers. Being located on the cable side of the associated earth switches poses operational difficulties during maintenance.

There are no other design issues associated with Alstom circuit breakers.

Future management strategy

It is recommended that first maintenance be carried out after 18 years in operation and repeated every six years thereafter.

Internal arc fault containment

The above mentioned Alstom switchgears are classified as compliant in regards to arc flash hazard. The manufacturer switchgear manual indicates that the switchgear is IAC (Internal Arc Contained) including racking of the circuit breaker behind arc proof door and reliable shields for operators safety.

Areva

Table 7: List of all in service Areva indoor HV switchgear

CB type	Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [Years]	Number of units
HVX	Vacuum	Devonport	22	A552,A652,A852,B552,B652, B852,C252,C552,C652,D252, E252,F252,G252,H252, J252,K252,L252,M252, N252,P252,Q252	2006	10/11	21
		Port Latta	22	A552,A852,B252,B552, C252,D252,E252,F652, G252,H252,J252	2006	11	11
		Savage River	22	B552B852,C552,F252, G252,H252,J252,K252, L252,M252	2006	11	10
		Wesley Vale	11	C552,C852,D552,J252, K252,L252,M252,N252, P252,Q252	2006	11	10
Total number of switchbays in service							**52**

Condition

Areva type HVX 22 and 11 kV switchgear is in an acceptable electrical condition.

Design

There are no known design issues associated with this type of switchgear.

Future management strategy

It is recommended that first maintenance on Areva circuit breakers be carried out after 18 years in service and repeated every six years thereafter.

Internal arc fault containment

The above mentioned AREVA switchgear is classified as compliant in regards to arc flash hazard. The IAC (Internal Arc Containment) includes racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

ABB

Table 8: List of all in service ABB indoor HV switchgear

CB type	Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
UniSafe VD4	Vacuum	Bridgewater	11	A252, A552, A852, B252, B552, C252, D252, E252, F252, G252, H252, J252, K252, L252, M252, N252, P252	2017	0	17
		Burnie	22	A852, B252, C252, D252, E252, F252, F552,G252, G552, H252, J252, K252, L252, M252, N252, P252, Q252	2004/ 2008	13/8	17
		Chapel Street	11	C652,D652,E652, F652	2008	9	4
		Derby	22	A252, A552, B252, C252, F252	2005/ 2013	11/4	5
		Hadspen	22	A652,A852, B252, B652, C252, C552, D252, D552, E252, F252, G252, H252, J252, K252, L252, M252, N252, P252, Q252	2005/ 2006/ 2009	11/8	19
		Huon River	11	A552, B252, C252, D252, E252	200n7	10	5
		Kingston	11	A252, A552, A852, B252, B552, C252, D252, E252, F252, G252, H252, J252, K252, L252, M252, N252, P252	2017	0	17
		Knights Road	11	A652,B652	2008	9	2
		Mowbray	22	A652,B652	2009	7	2
		Railton	22	A652,B652	2009	7	2
		Rokeby	11	A252, A552, A852, B252, B552, C252, D252, E252, F252, G252, H252, J252, K252, L252, M252, N252, P252	2017	0	17
		Scottsdale	22	A552, A852, B552, C252, D252, E252, F252, G252, H252, J252	2004	12	10

BA1/VD4-12-25	Vacuum	Sorell	22	G252, H252	2004	13	2
		Ulverstone	22	A625, G252, H252	2007/2009	10/9	3
		Trevallyn	22	A652, B652, C652, D652	2009	8	4
Total number of switch-bays in service							**75**

Condition

ABB 22kV and 11 kV switchgear type VD4 Unisafe is in an acceptable electrical condition.

Design

In July 2008, a voltage transformer failed at Burnie Substation. The exact cause of this failure has not yet been identified. There are no other known design issues associated with this type of switchgear.

Future management strategy

It is recommended that first maintenance on ABB circuit breakers be carried out after 18 years in operation and repeated every six years thereafter.

Internal arc fault containment

The ABB new switchgear types Unigear / Unisafe ZS1 are classified compliant in regards to arc flash hazard. The IAC (Internal Arc Containment) includes racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

Brown Boveri

Table 9: List of all in service Brown Boveri indoor HV switchgear

CB type		Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
A1	HB	SF_6	Boyer	6.6	G552	1988	29	1
			Railton	22	A252, A552, A852, B252, B552, C252, D252, E252, F252, G252, H252,	1983	34	11
			Sorell	22	A252, A552, A852, B252, B552, C252, D252, E252, F252	1983/ 1984	34/33	9
			Ulverstone	22	A252, A552, A852, B252, B552, C252, D252, E252, F252	1983	34	9
Total number of units								**30**

Condition

Condition monitoring results for Brown Boveri switchgear indicates that the units are showing surface partial discharge activities that need to be checked on a regular basis to minimise the risk of flashover.

Design

Brown Boveri Type BA1 HB circuit breakers are of two design ratings. Bus coupler and incomer circuit breakers are fitted with heat sinks to increase the current rating. These heat sinks may strike the busbar shutters during the rack-in process and stays close to busbar shutters while the circuit breaker is racked in. This causes partial discharges to occur between the heat sink fins and the busbar shutters. So far, there have been four flashovers at Sorell Substation most likely caused due to presence of water leaks from ceiling vents installed on top of the switchboards and due to humidity producing ozone as a result of partial discharges. Evidence of similar partial discharge has been observed at two other sites where Type BA1 HB circuit breakers are installed, but there have been no flashovers at these sites. (For additional information on these incidents refer to documents D07/81522 and D08/347 in TRIM.) All three sites (Railton, Sorell, and Ulverstone) have been fitted with air conditioning units. The 22 kV switchroom at Railton Substation does not have any ceiling vents and the ceiling vents above the switchroom at Ulverstone Substation were completely sealed off. The two ceiling vents in the roof above the 22 kV switchroom at Sorell Substation were removed and the roof was repaired using clip lock sheets to prevent water ingress into the switch bays thereby preventing internal flashovers.

Type BA1 cubicle which houses the bus coupler and incomer breakers are 1.0 metre wide while those which house feeder breakers are only 0.8 metres wide. These designs (circuit breakers and cubicles) are no longer available in the market and it has become extremely difficult to find spare parts for them.

Apart from the major issue above, following faults/issues have been observed on the Brown Boveri circuit breakers:

- spring wound indicator fault at one of the circuit breakers at Ulverstone Substation - the unit had to be sent interstate for repairs;
- issue with limit switch at Railton Substation – circuit breaker could not be closed and needed adjustment;
- trip coil burnt on one feeder circuit breaker at Sorell Substation;
- Need new SF6 gauges fitted to all circuit breakers – already fitted on some of the circuit breakers at Sorell and Ulverstone substations.

Future management strategy

The recommended maintenance practices will be continued for Brown Boveri switchgear. The damaged busbar shutters of the existing bus coupler circuit breakers need to be replaced. In the event of a non-repairable failure, the new type VD4 circuit breakers can be retrofitted into the existing BA1 cubicles through the use of an adapter truck. These units should be considered for replacement due to condition and that they are not arc fault rated. The units at Sorell, Railton and Ulverstone are currently proposed to be replaced between 2022 and 2024

Internal arc fault containment

The existing BBC BA1 switchgears at Railton, Sorell, and Ulverstone are classified as non- compliant in regards to arc flash hazard. To improve the safety of the operators while manually charging the spring of the mechanism, internal arc containment feature to be considered. The IAC (Internal Arc Containment) should include racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

GEC Australia

Table 10: List of all in service GEC indoor HV switchgear

CB type	Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
SBV2	Vacuum	Knights Road	11	A252, A552, A852, B552, C252, D252, E252, F252, G252, H252	1987	30	10
OLX3	Oil	North Hobart	11	A552, A852, B252, B552, B852, C252, C552, D252, D552, E252, F252, G252, M252, N252, P252, Q252, R252, S252	1977	40	17
Total number of units							**27**

Condition

Condition monitoring results for GEC Australia switchgear indicates that the units are in an acceptable electrical condition.

Design

GEC Australia type OLX3 circuit breakers installed at North Hobart Substation do not have spring wound motors installed in them. The springs have to be charged manually after each operation. They have oil as the insulant and are required to be maintained more frequently than modern equivalent units.

Future management strategy

The recommended maintenance practices will be continued for GEC Australia switchgear until their replacement. It would be sufficient to carry out maintenance on type SBV2 switchgear every 6 years and on type OLX3 every 3 years as per existing maintenance charts. Type OLX3 circuit breakers installed at North Hobart Substation are 35 years old and costly to operate and maintain. They will be replaced at the end of their service life. There is a current project being progress at present that will see the North Hobart units replaced by 2020. There is also a project proposed for the 2019-24 regulatory period for the replacement of Knights Road switchgear due to age and the lack of internal arc fault containment. This is expected to be completed by 2024.

Internal arc fault containment

The existing GEC OLX3 switchgear at North Hobart is classified as non-compliant from point of view of arc flash hazard. To improve the safety of the operators while manually charging the spring of the mechanism, internal arc containment feature to be considered. The IAC (Internal Arc Containment) should include racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

Merlin Gerin

Table 11: List of all in service Merlin Gerin indoor HV switchgear

CB type		Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
FLUAIR F200	FG2	SF_6	Boyer	6.6	952AB, A352, A552, B352, B552, C352, H352	1988/ 1995/ 1996	29/ 22/ 21	7
FLUAIR F100					952DE, C552D, C552F, D352, D552E, D552G, E352, G352, F352	1988	29	9
Belledonne 200 panel	DSE46	Air	Emu Bay	11	A852, B552, C252, C552, D252, F252, G252, H252	1977	40	8
Total number of units in service								**24**

Condition

Condition monitoring results for Merlin Gerin switchgear indicates that the units are producing surface partial discharge in the 6.6 kV FLUAIR 100 &200 at the Boyer switchgears and also in the 11 kV Belledonne 200 switchgear at Emu Bay.

Design

The 11 kV Merlin Gerin switchgear type Belledonne 200 at Emu Bay Substation is an air insulated design that has an air chamber for arc quenching. The 6.6 kV Merlin Gerin switchgear type FLUAIR 100 & 200 has shown ingress of dusts and contaminants through the gaps of the enclosures and mechanical vibration of covers. This has contributed to the surface discharge activities within the switch panels. Other than this there are no particular design issues with Merlin Gerin switchgear.

Future management strategy

The recommended maintenance practices will be continued for Merlin Gerin switchgear until their replacement. There is a current project being progressed at present that will see the Emu Bay units replaced by 2020. There is also a project proposed for the 2019-24 regulatory period for the replacement of Boyer switchgear due to age and the lack of internal arc fault containment. This is expected to be completed by 2026.

Internal arc fault containment

The existing Merlin Gerin type FLUAIR 100 & 200 switchgears at Boyer and type Belledonne 200 at Emu Bay are classified as non-compliant in regards to arc flash hazard. To improve the safety of the operators, internal arc containment feature to be considered. The IAC (Internal Arc Containment) should include racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

Schneider

Table 12: List of all in service Schneider indoor HV switchgear

CB type	Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
SM6	SF6	Newton	22	A252,A552	2013	4	2
			11	B552,D352	2013	4	2
Total number of switch-bays in service							**5**

Condition

Schneider 22kV and 11 kV switchgear type SM6 are in an acceptable electrical condition.

Design

No know design issues.

Future management strategy

It is recommended that first maintenance on Schneider circuit breakers be carried out after 18 years in operation and repeated every six years thereafter.

Internal arc fault containment

The Schneider switchgear type SM6 are classified compliant in regards to arc flash hazard. The IAC (Internal Arc Containment) includes racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

Siemens

Table 13: List of all in service Siemens indoor HV switchgear

CB type		Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
8BK20	3AF	Vacuum	Avoca	22	A252, A552, B252, C252, D252	2000	17	5
			Meadowbank	22	A252, A552, B252, C252	2000	17	4
	3AH		Electrona	11	A552, A652, A852, B552, B652, C252, D252, E252, F252, G252, H252, J252, K252, L252	2008	8	14
			George Town	22	A852, B252, C252, D252, D552, E252,	2000/ 2003/	17/14/ 10	15

					E552, F252, G252, K252, L252, M252, N252, P252, Q252	2007		
			Kermandie	11	A552, A852, B252, B552, C252, D252, E252, F252, G252, H252	2006	11	10
			Kingston	33	B852, C552, D552, N252, P252, Q252, R252, S252, T252, U252, V252	2012	5	11
			Lindisfarne	33	B552, B852, C552, E252, F252, G252, H252, J252, K252, L252, M252	2006/ 2008	11/9	11
			Mornington	33	A252, A552, A852, B252, B552, C252, D252, E252, F252, G252, H252	2011	6	11
			Mowbray	22	A552, B252, B552, C252, C852, E252, F252, G252, H252, J252, K252, L252, M252, N252, P252, R252, S252	2006/ 2009	10/8	17
			Palmerston	22	A852, B252, C252, C552, D252, D552, E252, F252, G252, H252	2006	10	10
			Queenstown	22	A252, A552, A852, B252, B552, C252	2004	13	6
				11	B852, C552, D552, F252, G252	2004	13	5
			Risdon	33	B252, C252, D252, E252, F252, G252, G552, G852,	2006/2007	11/10	14

					H252, H552, H852, J252, J552, K252			
				11	A552, AB852, B552,C352, CD852, D352, E352, F352, K352, L552, M552, N552, P552, Q352, R352, S352, T352, U352, V352, W552, X552	2001/2006	16/11	21
			Smithton	22	A552, A852, B252, B552, C252, D252, G252, H252, J252	2003	14	9
			St Leonards	22	A552, A852, B252, B552, C252, D252, E252, F252, G252, H252, J252, K252, L252, M252, N252	2012	5	15
			Triabunna	22	A552, A852, B552, C252, D252, E252, F252, G252, H252	2006/2008	10/9	9
			Tungatinah	22	A252, A552, B252, C252, D252, E252	2011	6	6
Total number of units in service								**193**

Condition

In general, the condition of the Siemens switchgear indicates that it is in an acceptable electrical condition. Some partial discharge activities were noted during PD survey and also during the commissioning tests.

Design

In April 2006 a vacuum canister of circuit breaker E252 at George Town Substation failed during a fault incident. The faulty circuit breaker was sent to manufacturer's facility for inspection. No conclusive evidence was found to establish the actual cause of failure although it was attributed to an over voltage flashover. Siemens supplied and installed a new circuit breaker in December 2006 and the faulty unit was retained by it. Similar faults have not recurred and the incident appears to be an isolated event. Other than this incident, Siemens vacuum circuit breakers have been very reliable and have no particular design issues.

Future management strategy

It is recommended that first maintenance on Siemens circuit breakers be carried out after 18 years in operation and repeated every six years thereafter.

The manufacturer's fault investigation report recommends that the vacuum interrupter bottles are inspected for signs of damage or cracking to the porcelain during periodic maintenance.

Internal arc fault containment

The above SIEMENS make switchgears are classified as compliant from point of view of arc flash hazard. The IAC (Internal Arc Containment) includes racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

Sprecher & Schuh

Table 14: List of all in service Sprecher & Schuh indoor/outdoor HV switchgear

CB type		Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
PED 206	HPTW	Oil	Norwood	22	A252, A552, A852, B252, B552, C252, D252, E252, F252, G252, H252	1979/1980	37	11
XX	AE45	Oil	Rosebery	44	A252, A552, B252, E452	1984	33	4
Total number of units								**15**

Condition

Condition monitoring results for the 22 kV Sprecher & Schuh indoor switchgear at Norwood indicates that they are in poor electrical condition. As well the 44 kV outdoor switchgear at Rosebery is also considered to be in poor condition.

Design

Incomer and bus-coupler circuit breakers have a very narrow tolerance (gap) with the cubicle and cause delays in the racking in process. Other than this there are no other identified design issues with the Sprecher & Schuh type HPTW switchgear.

Future management strategy

The recommended maintenance practices will be continued for Sprecher & Schuh switchgear until their replacement. There are current plans to replace the 22 kV switchgear at Norwood by 2019 and the 44 kV switchgear at Rosebery by 2022 due to being oil insulated, having no arc fault containment and in generally poor condition.

Internal arc fault containment

The Sprecher & Schuh type HPTW switchgear is classified as non- compliant in regards to arc flash hazard. The IAC (Internal Arc Containment) includes racking behind arc proof door, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

Whipp & Bourne

Table 15: List of all in service Whipp & Bourne indoor HV switchgear

CB type(s)		Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
CV	CV/2000CV31 CV36	Vacuum	Chapel Street	11	A252, A852, B252, B852, C252, D252, E252, E552, F252, F552, G252, G552, H252, H552, J252, K252, L252, M252, N252, P252, Q252, R252 S252, T252, U252, V252, W252, X252, Y252, Z252	1983	34	30
Total number of units								**30**

Condition

Condition monitoring results for 11 kV Whipp & Bourne indoor switchgear indicates that the units are in acceptable electrical condition.

Design

Whipp & Bourne 11 kV indoor switchgear installed at Chapel Street Substation are not of rackable type. There had been minor issues with their mechanism jamming, but has not been identified as a significant problem.

Future management strategy

A number of circuit breakers are redundant at the moment and some spares are available in stores as well. The recommended maintenance practices will be continued for Whipp & Bourne switchgear until their replacement. This switchgear will be replaced at the end of their service life and there is a proposal that they be replaced due to their age and that they do not have arc fault containment features by 2023.

Internal arc fault containment

The Whipp & Bourne switchgear is classified as non- compliant in regards to arc flash hazard. The IAC (Internal Arc Containment) includes racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

Yorkshire

Table 16: List of all in service Yorkshire indoor HV switchgear

CB type	Interrupting Insulant	Location	Voltage (kV)	Device Number	Year	Age [years]	Number of units
YSF6	SF6	Boyer	22	G452	1998	19	1
		New Norfolk	22	A552, A852, B552, A252, B252, C252, D252, H252, J252, L252	1987/1988	30/29	10
		St Marys	22	A552, A852, B552, C252, D252, E252,	1984/	32/3	8

				F252, G252	2013		
Total number of units							**19**

Condition

Condition monitoring results for 6.6 kV and 22 kV Yorkshire indoor switchgear indicate that the units are in acceptable electrical condition, although issues have been noted at St Marys with PD.

Design

Yorkshire SF6 circuit breakers have a history of gas leaks and a number of circuit breakers have been topped up several times. The SF6 seal needs to be replaced due to aging. The gas filling point needs to be extended to the front of the CB truck. This modification has been implemented by cycling through the New Norfolk and St Marys circuit breakers one at a time.

Future management strategy

There are five spare circuit breakers (22 kV) located in stores and another two at New Norfolk and St Marys. The recommended maintenance practices will be continued for Yorkshire SF6 switchgear until their replacement. There is a current approved project to replace the units at St Marys and New Norfolk which is expected to be completed by 2019.

Internal arc fault containment

The Yorkshire switchgear is classified as non- compliant from the point of view of arc flash hazard. The IAC (Internal Arc Containment) includes racking behind arc proof door, retrofit of pressure relief flaps to busbars and CT chambers, retrofit of arc shields to ends of switchboard, retrofit of containment and deflector system to give 3-sided safety as per AS 62271-200.

14 Appendix D – Outdoor HV Switchgear Condition Assessment

Outdoor HV switchgear has been grouped by location and assessed on two key criteria: electrical condition and design considerations. Based on electrical condition and design issues, future management strategies for each type are determined.

Arthurs Lake Substation

Table 17: List of all in service Nulec outdoor HV switchgear

Switchgear type	CB type	Interrupting Insulant	Voltage (kV)	Device Number	Year	Age (Years)	Number of units
Nulec	N15	SF_6	6.6	A352	2013	4	1

Condition

The Nulec recloser at Arthurs Lake Substation is in an acceptable electrical condition.

Design

Other than the general difficulties in maintaining pole mounted switchgear, there is no known design issues associated with these switchgear at Arthurs Lake Substation.

Future management strategy

The recommended maintenance practices should be continued for all HV switchgear at Arthurs Lake Substation.

Derwent Bridge Substation

Table 18: List of all in service outdoor HV switchgear at Derwent Bridge Substation (22 kV)

Asset	Manufacturer	Type	Voltage	Devices	Year	Age [years]	Number of units
Circuit breaker	Nulec	N24-150	22 kV	A252	2008	9	1
Disconnector	ABB	S-Series	22 kV	A229A, A229B, A229D	1975	42	3
Current transformer	Mounted inside CB (re-closer)			-			
Voltage transformer	Modern Products	VT238	22 kV	A597	1996	21	1
Combined voltage & current transformer	TWS	SBH90	22 kV	A296/97	2003	14	1

Figure 9: Pole mounted 22 kV switchgear at Derwent Bridge Substation

Condition

All 22 kV switchgear at Derwent Bridge Substation is in an acceptable electrical condition. Nulec circuit breaker with auto-reclose facility was replaced in 2008 during supply transformer replacement following a failure of the previous Nulec recloser control card.

Design

Other than the general difficulties in maintaining pole mounted switchgear, there is no known design issues associated with these switchgear at Derwent Bridge Substation.

Future management strategy

The recommended maintenance practices should be continued for all 22 kV switchgear at Derwent Bridge Substation.

Que Substation

Table 19: List of all in service outdoor HV switchgear at Que Substation (22 kV)

Asset	Manufacturer	Type	Voltage	Devices	Year	Age [years]	Number of units
Circuit breaker	Magrini Galileo	GI-E	22 kV	A552	2006	10	1
Disconnector	ABB	DBRP	100 kV	A129	2004	12	1
	Stanger	HSB	22 kV	B229	1984	33	1
Current transformer	Sadtem	KE5	22 kV	A296	1980	37	1
	Scarpa Magnano	AMT 245	22 kV	A596	2006*	44	1
Voltage transformer	Sadtem	YE8C	22 kV	A297, A597, B297	1980	37	3
Combined voltage & current transformer	-	-	22 kV	A296D/07	-	-	1

* Ex-Meadowbank C296 installed in 2006 (about 44 years old).

Figure 10: 22 kV switchgear at Que Substation

Condition

At Que Substation there is only one circuit breaker, a 22 kV Magrini Galileo, manufactured in 1997. Also there are two disconnectors, two current transformers, three VTs and a combined CT/VT. These 22 kV switchgear are generally in acceptable electrical condition. There have been a number of 22 kV current transformer failures and protection related incidents at Que Substation - more recently in January 2007, April 2007, and February 2008 and in April 2008.

Design

There were several occasions where protection systems did not operate as designed due to equipment failures at Que Substation. In April 2007 and February 2008 transformer T1 interrupted due to protection equipment failure and/or feeder faults. There were 22 kV current transformer failures in January 2007 and April 2008. (Refer Table 1 for more details on these incidents.)

Future management strategy

Failed equipment has been replaced from time to time. The CT failed in April 2008 was replaced with the redundant CT on the other feeder circuit. Recommended maintenance practices will be continued for 22 kV switchgear at Que Substation.

Rosebery Substation

Table 20: List of all in service outdoor HV switchgear at Rosebery Substation (44 and 22 kV)

Asset	Manufacturer	Type	Voltage	Devices	Year	Age [years]	Number of units
Circuit breaker	Siemens	SPS72	44 kV	B552, C252, D252, D452	1997	20	4
	Schneider	RM6	22 kV	F452	2015	1	1
	Sprecher & Schuh	AE45	44 kV	A252, A552, B252, E452	1984	33	4
Disconnector	AEM	DB44	44 kV	E429C, E429, D429, C229C, C229, B829, B529, B229,	2000	17	12

				A229D, A229C, A229, E429D			
	Stanger	HSB	22 kV	E229C, E529C, D529C	1983	34	3
	Taplin	D979	44 kV	C529, A529, C829, D229D, C229D, B229D, A829, D229C, D229	1953-1983*	64/34	9
Current transformer	Balteau	SDG72	44 kV	A296, A596, B296, E496	1983	33	4
	Sadtem	-	44 kV	A596, B596	2005	11	2
	Tyree	ED1888	22 kV	D596, E596	1957	59	2
Voltage transformer	Asea	EMFC52	44 kV	A297A, A297B	1972	44	2
	Emek	HGT-66	44 kV	A897, B897	2001/2004	15/12	2
	Tyree	05/24/31	22 kV	D597, E597	1983	33	2

- these are located indoors, * different years

Condition

Rosebery Substation contains both 44 kV and 22 kV switchgear manufactured by ten different manufacturers. Some of the equipment is young (7–15 years old) while other equipment ranges from 29 to 59 years of age.

Design

In February 2007, Sprecher & Schuh 44 kV circuit breaker E452 failed to open for a downstream fault, due to a dislodged support screw associated with the tripping mechanism. This was replaced and the problem has not recurred.

There have been persistent SF6 gas leaks from the SPS72 units. Other than that there are no particular issues with the outdoor switchgear at Rosebery Substation.

Future management strategy

Currently, different supply options are being studied for the Rosebery area in conjunction with other redevelopments in the surrounding substations. Recommended maintenance practices will be continued until replaced. A project has been proposed in the 2019-2024 regulatory period for the replacement of all 44 kV switchgear and overhead structure with ground mount GIS units.

15 Appendix E – Spare HV Switchgear Units

The following tables detail TasNetworks' spare indoor and outdoor HV switchgear unis that are deemed suitable for service.

Table 21: Indoor spare HV switchgear listing

Manufacturer	Type	Voltage (kV)	Spare location	Age [years]	Number of units	Installed Site(s)
Alstom	FPX-24 25 06	22	Trevallyn	21	1	Trevallyn
Alstom	FPX-24 25 20	22	Trevallyn	21	5	Trevallyn
Alstom	WSA 6/36-2/623	33	Primary Store	15	1	Creek Rd
Areva	HVX 24-25-08-E	22/11	Primary Store	11	1	Devonport, Port Latta, Savage River, Wesley Vale
Areva	HVX 24-25-20-E	22/11	Primary Store	11	1	Devonport, Port Latta, Savage River, Wesley Vale
ABB	VD4/P 24.20.25	22/11	Hadspen	12	2	Hadspen, Huon River
ABB	VD4 24.06/16	22	Burnie	14	2	Burnie, Derby, Scottsdale
ABB	VD4 24 12 25	22	Primary Store	9	1	
Brown Boveri	HB24.06.12C	22	Primary Store	34	1	Railton, Sorell, Ulverstone
GEC Australia	OLX3	11	North Hobart	39	1	North Hobart Knights Rd
	SBV2/630		Knights Road	30	1	
Merlin Gerin	DSE46	11	Emu Bay	33/43	4	Emu Bay
Reyrolle	LM23T2 LM36T	11	Bridgewater, Primary Store, Rokeby	37 38	2 1	Bridgewater, Kingston, Rokeby.
Schneider	SM6-24	22/11	Primary Store	4	1	Newton
Siemens	3AH1114-4	11	Risdon	16	2	Risdon
Siemens	3AH1262-2	22	Primary Store	13	1	Queenstown
Siemens	3AH3116-7	11	Risdon	16	1	Risdon
Siemens	3AH3264-4	22	Primary Store	13	2	Queenstown, Smithton
Siemens	3AH3305-6	33	Risdon	10	1	Kingston, Lindisfarne, Mornington, Risdon
Siemens	3AH5262-2	22	Primary Store	17	3	George Town, Meadowbank, Smithton

Siemens	3AH5274-2	22		6	0	Tungatinah
Siemens	3AH5284-2	33	Primary Store	5	1	Electrona, Kermandie, Kingston, Triabunna
Siemens	3AH5284-6	22	Primary Store	11	2	Electrona, Kermandie, Palmerston, Triabunna, Tungatinah
Siemens	3AH5314-2	33	Lindisfarne	12	1	Lindisfarne, Mornington, Risdon
Sprecher & Schuh	HPTW 406e	22	Norwood	37	1	Norwood
Yorkshire	YSF6	22	New Norfolk, Primary Store, St Marys	30	7	Boyer, New Norfolk, St Marys

Table 22: Outdoor spare HV switchgear listing

Manufacturer	**Type**	**Voltage (kV)**	**Location**	**Age [years]**	**Number of units**	**Installed Site(s)**
Magrini Galileo	Gi-E	22?	Primary Store	20	1	Que
Sprecher & Schuh	AE45/1000/8-12	44	Rosebery	34	1	Rosebery

16 Appendix F – Summary of HV switchgear- by site

The following tables details TasNetworks' indoor and outdoor HV switchgear.

Table 23: Sites with indoor switchgear

Site	Site Abb	Voltage		HV Switchgear				
		Rated	Operating	Make	Insulant	Year	Age [years]	Numbers
Arthurs Lake*	AL	12 kV	6.6 kV	Nulec	SF_6	2013	4	1
Avoca	AV	24 kV	22 kV	Siemens	Vacuum	2000	17	5
Boyer	BY	7.2 kV 7.2/12 kV 24 kV	6.6 kV 6.6 kV 22 kV	Brown Boveri Merlin Gerin Yorkshire	SF_6 SF_6 SF_6	1988 1988 1988	29 28 21 20 18 19	1 16 1
Bridgewater	BW	12 kV	11 kV	ABB	Vacuum	2015	2	17
Burnie	BU	24 kV	22 kV	ABB	Vacuum	2004	8 13	17
Chapel Street	CS	12 kV	11 kV	Whipp & Bourne ABB	Vacuum	1983	34 8	30 4
Creek Road	CR	36 kV	33 kV	Alstom	Vacuum/GIS bus	2002	15 13	10 6
Derby	DF	24 kV	22 kV	ABB	Vacuum	2005	11 4	4 1
Devonport	DP	24 kV	22 kV	Areva	Vacuum	2006	10	21
Electrona	EL	24 kV	11 kV	Siemens	Vacuum	2008	8	14
Emu Bay	EB	N/A	11 kV	Merlin Gerin	Air	1977	40	8
George Town	GT	24 kV	22 kV	Siemens	Vacuum	2000	16 13 10	12 2 1
Hadspen	HA	24 kV	22 kV	ABB	Vacuum	2006	11 7	17 2
Huon River	HR	24 kV	11 kV	ABB	Vacuum	2007	11	5
Kermandie	KE	24 kV	11 kV	Siemens	Vacuum	2006	11	10
Kingston	KI	12 kV	11 kV	ABB	Vacuum	2015	2	17
		36 kV	33 kV	Siemens	vacuum	2012	5	11
Knights Road	KR	12 kV	11 kV	GEC Australia	Vacuum	1987	29 8	10 2
Lindisfarne	LF	36 kV	33 kV	Siemens	Vacuum	2006	11 8	9 2

Meadowbank	MB	24 kV	22 kV	Siemens	Vacuum	2000	16	4
Mornington	MO	36 kV	33 kV	Siemens	Vacuum	2011	6	11
Mowbray	MY	24 kV	22 kV	Siemens	Vacuum	2006	10 7	16 3
New Norfolk	NN	24 kV	22 kV	Yorkshire	SF_6	1987	30 28	6 4
Newton	NT	24 kV	22 kV	Schneider	SF6	2013	4	4
North Hobart	NH	12 kV	11 kV	GEC Australia	Oil	1977	39 7	17 1
Norwood	NW	24 kV	22 kV	Sprecher & Schuh	Oil	1980	37	11
Palmerston	PM	24 kV	22 kV	Siemens	Vacuum	2006	10	10
Port Latta	PL	24 kV	22 kV	Areva	Vacuum	2006	11	11
Queenstown	QT	24 kV 24 kV	11 kV 22 kV	Siemens Siemens	Vacuum Vacuum	2004 2004	13 13	5 6
Railton	RA	24 kV 24 kV	22 kV 22 kV	Brown Boveri	SF_6 Vacuum	1983 2009	34 7	11 2
Risdon	RI	12 kV 36 kV	11 kV 33 kV	Siemens Siemens	Vacuum Vacuum	2001 2006	16 10	21 14
Rokeby	RK	12 kV	11 kV	ABB	Vacuum	2015	2	17
Savage River	SR	24 kV	22 kV	Areva	Vacuum	2006	11	10
Scottsdale	SD	24 kV	22 kV	ABB	Vacuum	2005	12	11
Smithton	ST	24 kV	22 kV	Siemens	Vacuum	2003	13	9
Sorell	SO	24 kV 24 kV	22 kV 22 kV	ABB Brown Boveri	Vacuum SF_6	2004 1984	13 34	2 9
St Leonards	ST	24 kV	22 kV	Siemens	Vacuum	2012	4	15
St Marys	SM	24 kV	22 kV	Yorkshire	SF_6	1984	32 3	6 2
Trevallyn	TR	24 kV 24 kV	22 kV 22 kV	Alstom ABB	SF_6 Vacuum	1997 2009	20 7	23 4
Triabunna	TB	24 kV	22 kV	Siemens	Vacuum	2006	10	9
Tungatinah	TU	24 kV	22 kV	Siemens	Vacuum	2011	6	6
Ulverstone	UL	24 kV 24 kV	22 kV 22 kV	ABB Brown Boveri	Vacuum SF_6	2007 1983	9 34	3 9
Wesley Vale	WV	24 kV	11 kV	Areva	Vacuum	2006	11	10
								545

* indoor switchgear located outside (in a panel)

Table 24: Sites with indoor switchgear by operating voltage

Operating Voltage	Single Voltage				Dual Voltage*		
	6.6 kV	11 kV	22 kV	33 kV	6.6/22 kV	11/22 kV	11/33 kV
No. of sites	1	10	22	3	1	2	2

* - 6.6/22 kV at Boyer, 11/22 at Queenstown and Newton, and 11/33 kV at Risdon and Kingston

Table 25: Sites with outdoor switchgear

	Site	Site Abb.	HV Switchgear					
			Voltage	Make	Insulant	Year	Age [years]	Nos
1	Derwent Bridge	DB	22 kV	Nulec	Vacuum*	2008	8	1
2	Arthurs Lake	AL	6.6 kV	Nulec	SF6	2013	3	1
3	Que	QU	22 kV	Magrini Galileo	SF6	2006	10	1
4	Rosebery#	RB	44 kV	Siemens	SF6	1997	19	4
			44 kV	Sprecher & Schuh	Oil	1984	33	4
			22 kV	Schneider	SF6	2015	1	1
Total								**12**

* - Nulec CB's have vacuum interrupters housed in an SF6 filled tank.

- There are no 22 kV circuit breakers at Rosebery Substation, only switching fuse disconnectors. The four fuse disconnectors at Rosebery were decommissioned and removed in 2010 as part of site upgrade and the safety risks due to high level of partial discharge activities.