STRATEGY

ELECTRICITY PRIMARY PLANT ASSET CLASS STRATEGY

ELE-999-PA-IN-008

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PUBLIC

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DOCUMENT HISTORY

Revision	Date	Description of Changes
0	30/08/2017	Combined ZSS ACS into one document & enhanced to new template Combined ZSS ACS into one document & enhanced to new template
1	02/07/2018	Updates and additions to address Information, Risk, Spares and Criticality definition. Executive summary updated. Transformers and other sections amended to standardise and correct content. CBRM updated to reflect ZSS NS and ZSS P updates.
1.1	16/11/2018	General update. Update of all the asset data, graphs and CBRM information. Addition of JEN Zone Sub addresses.
1.2	1/4/2019	General Updates following external review
1.3	30/10/2019	General Updates following second external review
2	20/12/2019	Updated Executive Summary
2.1	30/12/2019	Section 1, 2, 3 condensed, and 5 updated
3.0	01/04/2022	Updated document template
4.0	01/03/2023	Updated Sub-Asset Classes and Clauses
5.0	09/12/24	ACS update – EDPR submission

OWNING FUNCTIONAL GROUP & DEPARTMENT / TEAM

Electricity Distribution: Asset & Operations Electricity: Network Assets

REVIEW DETAILS

Review Period:	Review Date + 3 years
Next Review Due:	February 2027

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EXECUTIVE SUMMARY

Jemena Electricity Networks (Vic) Ltd., operating under a Victorian electricity distribution license has an Asset Management System that contains a set of four Asset Class Strategy documents.

This ACS document pertains to Electricity Primary Plant, a term that denotes a range of equipment that is used in zone substations.

The first three sections of this ACS are common to all the ACS documents. The fourth section is where the Electricity Primary Plant is unpacked and divided into zone substation sub-asset classes, these include:

- Transformers;
- Circuit breakers;
- Disconnectors and buses;
- Instrument transformers;
- Capacitor banks;
- Buildings and grounds; and
- Earthing systems.

Each sub-asset class is described and discussed in terms of its associated risk, performance, life cycle management and budgetary forecasts.

In line with standard risk assessment, asset functional failure is a combination of probability and consequence. All the documented asset management strategies focus on keeping the probability of failure to a low level. This means using Condition Based Risk Management to achieve end-of-life asset replacement before serious failures occur.

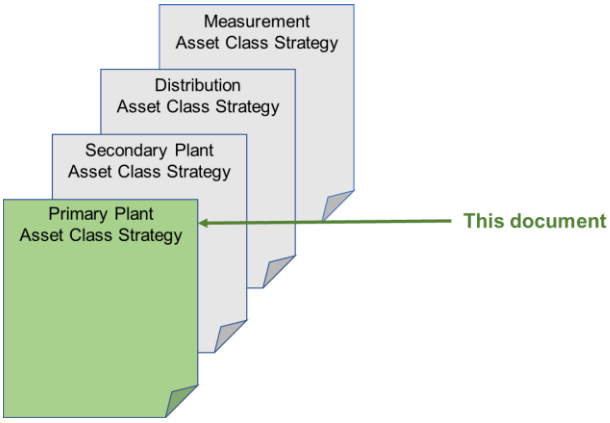
1. INTRODUCTION

This ACS covers the JEN primary plant asset class and outlines the methods employed, analysis undertaken, and actions to be taken to optimally manage the assets. The document prescribes the management of the primary plant asset class.

Asset life cycles are considered to consist of three stages: creation (acquisition), maintenance or replacement (as applicable), and disposal. Investment recommendations are made for each stage by analysing the in-situ asset condition and age profile.

There are four ACS documents. Each ACS outlines performance measures and objectives which are used to attain key performance targets. This gives visibility to the performance of the asset and, in turn, informs investment decision making.

Figure 1–1: ACS documents hierarchy



The primary plant assets in this ACS are categorised into the following sub-asset classes located in the following sections of this document:

- 4.1 Transformers, including station service transformers, Neutral Earthing resistors (NER) and Rapid Earth Fault Current Limiter (REFCL) or Arc Suppression Coil for resonant earthing;
- 4.2 Circuit breakers, both outdoor and indoor switchboards;
- 4.3 Disconnectors and buses (outdoor), including earthing switches and surge arresters and connections to assets;
- 4.4 Instrument transformers (outdoor stand-alone types) CTs & VTs;
- 4.5 Capacitor banks, including earthing switches and instrument transformers within the banks;
- 4.6 Buildings and grounds, including structures, yard facilities, drainage, bunding, security fences and walls; and
- 4.7 Earthing system, earth grid and connections.

1.1 PURPOSE

The purpose of the Electricity Primary Plant ACS is to document the practical approach that supports the delivery of our asset management objectives.

This ACS is based on key information about each sub-asset (including risk, performance, life cycle management, capital expenditure, and operational expenditure) and contributes to short, medium, and long-term planning.

This primary plant ACS addresses:

- Primary plant asset management practices;
- Sub-asset class risk causes and consequences;
- Sub-asset class performance against objectives, drivers, and service levels;
- Sub-asset class specifications and life cycle management of electricity primary plant assets in-service. Asset condition, along with relative cost considerations are the primary drivers in making asset maintenance versus asset replacement decisions; and
- Risk weighted decision-making and financial estimates used to inform operating expenditure and capital expenditure planning.

1.2 ASSET MANAGEMENT SYSTEM

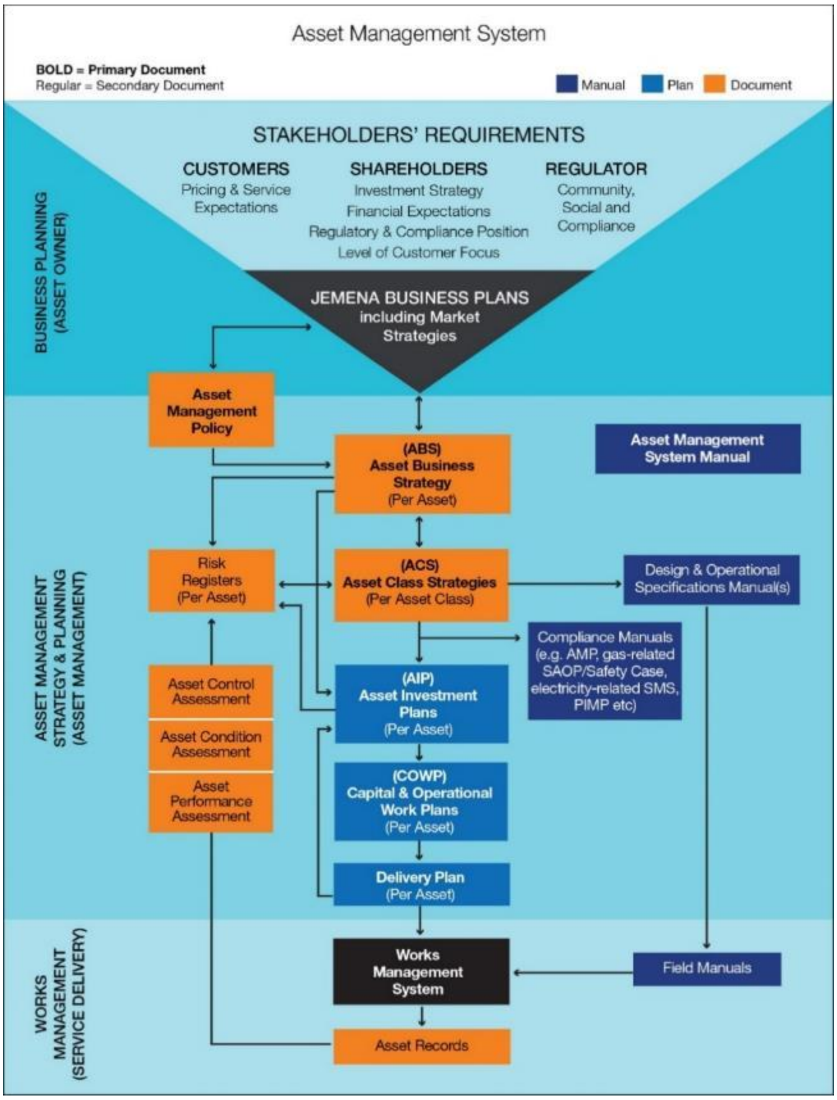
Asset management is the coordinated activity that we undertake to optimise the value of our electricity network when providing electricity distribution services to our customers. It involves balancing of efficient costs, opportunities and risks against performance. An AMS enables a systematic approach to the combination of management, economic, engineering, and other practices applied to physical assets to provide the required level of service in the most cost-effective manner, whilst managing future risks.

Our AMS enables us to effectively direct, coordinate and control asset management activities throughout an asset's whole life. It facilitates an optimal mixture of efficient and prudent capital investments, operations, maintenance, resourcing, risks, performance, sustainability and good governance.

Our AMS is accredited under the ISO55001 standard. Figure 1–2 shows the inputs and outputs of the AMS.

This ACS resides in JEN's AMS. The ACS ensures that the performance, risks and cost of each asset class are analysed, and optimum plans developed to align with the Business Plan.

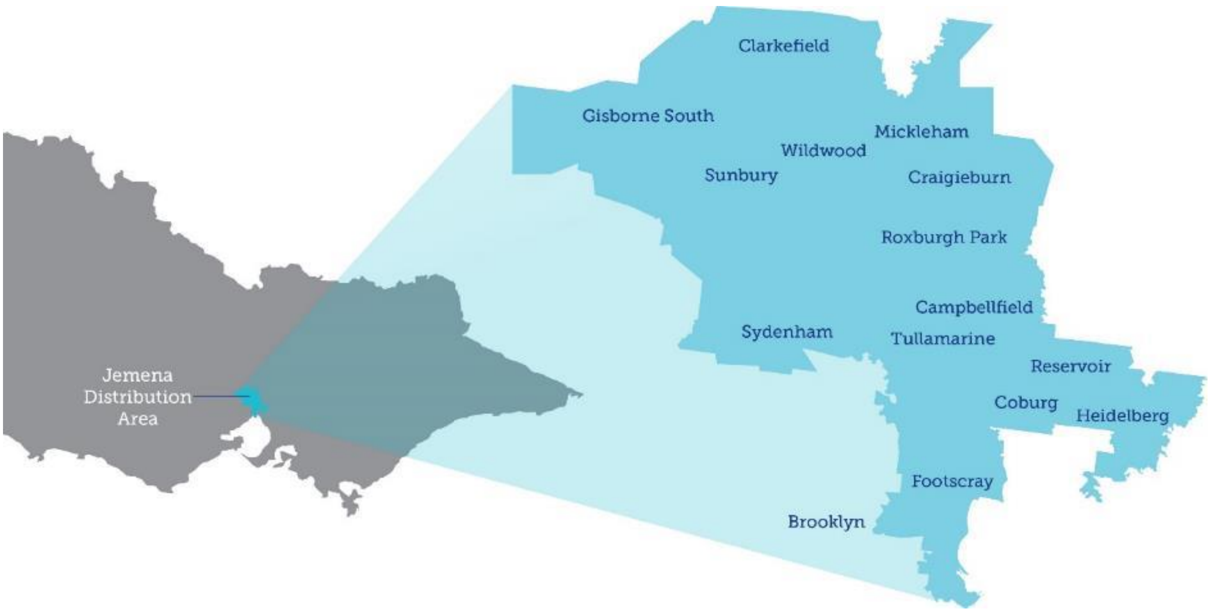
Figure 1–2: JEN's Asset Management System



1.3 DESCRIPTION OF ASSETS COVERED

The regulatory standard life set by the Australian Energy Regulator (AER) for distribution system assets is 49.5 years. The tax asset life set by the Australian Tax Office, for distribution system assets is 40 years. In the context of these asset lives, JEN has assessed that the expected nominal life of primary plant assets is 50 years. This can be seen as a peak in the number of assets installed around this period. Thirty-four per cent of transformers and 18% of circuit breakers are 50 years or older. Similarly, 38% of disconnectors, 5% of instrument transformers and 26% of capacitor banks are beyond 50 years of age.

Figure 1–3: JEN's geographical footprint



As of December 2024, JEN operates 27 zone substations and 7 HV customer substations with JEN assets installed[1]. These substations are equipped with:

- 68 power transformers ranging in age from 1 to 73 years of two main types: 66kV primary voltage and secondary voltages of 22kV, 11kV or 6.6kV and 22kV primary voltage and secondary voltages of 11kV or 6.6kV;
- 545 circuit breakers ranging in age from 0 to 85 years, comprising: 73 – 66kV CBs, 328 – 22kV CBs, 91 – 11kV CBs and 53 – 6.6kV CBs. The 66kV and 22kV CBs are installed in a mix of indoor and outdoor environments, with all the 11 and 6.6 kV CBs being indoor;
- 1284 disconnectors, isolators and earth switches ranging in age from 3 to 63 years and 118 outdoor buses ranging in age from approximately 2 to 62 years;
- 223 current and voltage transformers ranging in age from approximately 1 to 62 years of voltages 66 and 22 kV;
- 35 capacitor banks ranging in age from approximately 3 to 60 years; and

[1] Refer to Section 1.14 for a list of JEN zone substations and HV customer substations with Jemena assets installed.

- 34 zone substations including HV customer substations with JEN assets installed with buildings and other physical infrastructure ranging in age from 1 to 74 years.

1.4 GOVERNANCE

1.4.1 APPROVAL AND COMMUNICATIONS

The asset engineering manager updates ACS documentation every three years, which is then approved by the General Manager of Asset Management Electricity Distribution.

The ACS is reviewed every three years to ensure alignment with the Asset Management objectives and to account for any additional asset performance and risk information.

1.4.2 RESPONSIBILITIES

Key stakeholder personnel are shown below in Table 1-1.

Table 1-1: Asset Class Strategy Responsibilities

Job Title	Responsibility
Network Assets Manager	Document Owner
Principal Primary Plant Engineer	Primary Plant Responsible
Primary Team Leader	Primary Plant Sub-Asset Class Responsible
Senior Primary Plant Engineers	Primary Plant Sub-Asset Class Responsible

2. STRATEGIC DRIVERS

1.5 JEN MARKET STRATEGY

The Electricity Distribution services that JEN provides undergoes continuous change and plays a part in shaping the future state of the energy industry.

1.6 REGULATORY AND LEGISLATIVE

JEN meets legal, licence and regulatory obligations in order to comply with the National Electricity Law (NEL) and National Electricity Rules (NER), together with other rules, codes and guidelines set forth by:

- AER;
- Energy Safe Victoria (ESV); and
- Essential Services Commission (ESC).

JEN complies with the requirements of each of these stakeholders in order to adhere to its distribution licence requirements, NER requirements, and safety obligations. JEN is required to meet ongoing compliance, analysis, and reporting requirements regarding asset management. For example, JEN provides an annual RIN to the AER for all zone substation and distribution assets so as to account for the state of the network in terms of asset cost, age, reliability and cost of operating the network.

3. ASSET CLASS STRATEGY OBJECTIVES

ACS objectives are:

- Promoting a Health, Safety and Environmental (HSE) culture that proactively seeks to control HSE risks;
- Optimise asset availability. Each asset failure is recorded and evaluated. Using standard risk assessment guidelines, an estimate of equipment failure rates are made. Annual probabilistic failure rates can be derived. A documented inspection, condition monitoring, maintenance and replacement strategy is included in this document for all assets to minimise the probability of failure and contain deterioration in service levels;
- Optimise asset life cycle. Defer asset replacement expenditure by assessing an asset for failure using condition monitoring. Where practical, conduct routine inspections that can increase in frequency—as the asset approaches its statistical end of life. The aim is to defer capital expenditure whilst controlling the risk of failure and, thus, contain deterioration in service levels; and
- Standardisation and application of established design principles minimise the design and life cycle costs of assets installed. For instance, the standardisation of specifications for purchasing of primary plant assets together with the construction of zone substation physical assets and facilities, achieves efficiencies. These coordinated and integrated designs are mainly focused on attributes such as robust long life, security, reliability, efficient cost, and efficiency. Furthermore, we do not wait to consider disposal at end of life. Disposal of assets and associated components is accounted for within primary plant specifications and new asset evaluations prior to purchasing.

4. SUB-ASSET CLASS STRATEGY

The following recommendations for continuous improvement apply to multiple sub-asset classes and represents good Asset Management practices:

(1) The basis for managing the HV JEN fleet was assessed in 2000 using Reliability Centred Maintenance (RCM) consultants, facilitated by an American Company (International Reliability Consultants). Twenty-three years has elapsed since the maintenance frequency were determined. In 2009, IEC 60300-3-11 was created and provided a guideline for the development of failure management for equipment and structures using RCM analysis techniques. This standard is an extension of IEC 60300-3-10, IEC 60300-3-12 and IEC 60300-3-14. Maintenance activities recommended in all three standards, which relate to preventive maintenance, may be implemented using this standard. This edition applies to all industries and defines a revised RCM algorithm and approach to the analysis process.

(2) All Sub-Asset Class condition test results must be evaluated by the experienced and trained personnel conducting the work. Further effort must be applied to determine any poor test, maintenance or observation result at the time of the work is being performed. Guidelines are provided for condition assessment and recommended action for further work, or de-energisation of plant in “poor” condition. Results must be tabulated in the approved format and spreadsheet. Immediate notification shall be provided of all test results where the condition indicates a poor or bad condition warranting further assessment. Primary Plant Engineers are accountable for the assessment of all conditions and maintenance data for trend performance and deterioration and to make recommendations for further action, such as improving the maintenance tasks or frequency, undertaking emergency de-energisation, conducting risk assessment and prioritising asset replacements. Confidence in the asset condition data is essential.

(3) System Application and Products (SAP) has proved to be an invaluable tool for asset management.

(4) Lubrication selection for all mechanical devices, such as circuit breakers, disconnectors, isolator and earthing switches, and transformer mechanisms, is critical. The application of lubrication must follow approved guidelines to maintain performance and reliability. A contractor has been engaged to prepare a lubrication report. The report titled: “Risk Assessment Methodology for Application of New Switchgear Lubricant” is currently being reviewed and pending the final report, a trial will commence on zone substation assets.

The new lubricant under consideration is provided by the United States (US) based company [redacted] and it is intended to be used as a single replacement for the majority of other lubricants currently in use. [redacted] market the product as Minimal Disassembly Lubrication (MDL) and it is provided in a kit.

The results obtained from the investigation into the application of new lubricants from [redacted] product range appear to be positive.

(5) Primary Plant Condition Monitoring Equipment

A notional budget to purchase condition monitoring equipment is required, to keep up with industry standard and latest development of technology. The innovation of new test equipment and condition monitoring technology will support the life cycle management of primary HV assets, to identify incipient faults, degradation in performance before catastrophic failure.

(6) Procurement of Strategic Spares

A notional budget to purchase spare equipment is required in order to repair network equipment and restore supply, or to replenish spare equipment stock as required.

1.7 ZONE SUBSTATION (ZSS) TRANSFORMERS

This sub-class covers Zone Substation Transformers, including major components: 66kV bushings, on-load tap changers (OLTCs), plus NERs, Rapid Earth Fault Current Limiters (REFCL), Arc Suppression Coils and Station Service Transformers.

1.7.1 INTRODUCTION

The function of power transformers installed in Zone Substations is to transform sub-transmission voltage (66 or 22kV) to the distribution voltage (22, 11 or 6.6kV) used in the local area HV distribution network. The regulation of the distribution voltage at the zone substation bus is achieved by installing OLTC on or in the transformers. 66kV bushings provide an insulated connection between bare overhead conductors and the internal primary winding of the transformer. Distribution voltage connections are achieved either by HV outdoor bushings or HV cable box.

To limit the phase-to-earth fault current level, an NER is installed between the transformer neutral connection and the ZSS earth grid. Further to this, Arc Suppression Coils, will be installed at ZSS to further reduce fault current, to improve public safety and reduce the likelihood and consequence of arc flash exposure to employees. The likelihood of a single-phase fault developing into a 3-phase fault will be better controlled and minimised by an ASC. It is envisaged that all ZSS sites will ultimately be installed with resonant earthing.

A REFCL has been installed in the Coolaroo (COO) supply area to reduce phase-to-earth faults to very low energy levels quickly.

Station service transformers are connected to the HV distribution bus or feeder to provide an LV supply to the substation light and power requirements, including battery chargers for the DC system, which supplies protection, control and communication equipment needs. Higher capacity station service transformers have been installed at Coolaroo (COO) ZSS to supply inverters for the REFCL system.

This section includes information about the type, specifications, life expectancy and age profile of the power transformers in service.

JEN operates 26 zone substations and 7 HV customer substations[2]. The zone substations are equipped with 68 power transformers of two main types:

- 66kV primary voltage and secondary voltages of 22kV, 11kV or 6.6kV, depending on their geographical location; and
- 22kV primary voltage and secondary voltages of 11kV or 6.6kV.

Note: The HV customer substations with JEN assets installed do not contain JEN-owned transformers. The substations are: BLTS, MAT, NEI, SSS, VCO, and WGT. NEL substation solely contains JEN-owned assets, including transformers, and for now, supplies a single customer.

An urban zone substation typically has two or three 20MVA naturally cooled transformers (potentially increasing to 33MVA when fitted with fans and pumps) with some transfer capacity between adjacent zone substations. In two ZSSs, smaller 12/18MVA transformers have been installed.

Typically, a zone substation equipped with three power transformers supplies between eight to twelve distribution feeders and in excess of 10,000 customers.

A critical transformer component is 66kV bushings, particularly due to a history of failure and catastrophic consequences such as fires destroying the transformer. The JEN network has 62 power transformers which utilise 66kV bushings (186 in total) at 25 zone substations. This excludes the 3 transformers and 3 NER's at MAT which are owned by OVIDA.

There are three main types of 66kV transformer bushings:

- Synthetic Resin Bonded Paper (SRBP);
- Resin Impregnated Paper (RIP); and
- Oil Impregnated Paper (OIP)

The former State Electricity Commission of Victoria (SECV) standardised SRBP 66kV bushings for all power transformers manufactured prior to 1980.

1.7.2 ASSET SPECIFICATION

Table 4-1 lists the population, voltage ratio, ratings, and year of manufacture for this asset class. Zone Substation (ZSS) AW and BD have 4 high-rated transformers (30MVA to 40MVA) installed, whereas TH has 2 of the highest-rated transformers (45MVA) installed. ZSS EP, FF, PV, and NT transformers are the oldest on the network.

[2] Refer to Appendix K for a list of JEN zone substations and HV customer substations with JEN assets installed.

Table 4-1: Power Transformer Information

Zone Substation	Voltage Ratio	NER	Transformer MVA Capacity (Year of Manufacture)							
			1		2		3		4	
AW (Airport West)	66/22kV	Y	20/30	(1966)	20/30	(1981)	20/30	(1966)	20/40	(1988)
BD (Broadmeadows)	66/22kV	Y	20/30	(1973)	20/30	(1968)	20/30	(1968)	20/33	(2002)
BMS (Broadmeadows South)	66/22kV	Y	20/33	(2014)	20/33	(2014)				
BY (Braybrook)	66/22kV	Y	20/30	(1967)	20/33	(2006)				
CN (Coburg North)	66/22kV	Y	20/30	(1967)	20/30	(1967)	20/33	(1990)		
COO (Coolaroo)	66/22kV	Y[3]	20/33	(2007)	20/33	(2012)				
CS (Coburg South)	66/22kV	Y	20/33	(1976)	20/33	(1976)				
EP (East Preston)	66/6.6kV	N	20/27	(1962)	20/27	(2006)	10/13	(1959)	10/13	(1958)
EPN (East Preston)	66/22kV	Y					20/33	(2015)		
ES (Essendon)	66/11kV	Y			20/33	(2019)	20/33	(2018)		
FE (Footscray East)	66/22kV	Y	20/30	(2010)	20/30	(1967)				
FF (Fairfield)	22/6.6kV	Y	12/18	(2018)	12/18	(2018)	10/13	(1950)		
FT (Flemington)	66/11kV	Y	20/30	(1970)	20/30	(1970)				
FW (Footscray West)	66/22kV	Y	20/30	(1966)	20/30	(1966)	20/30	(1971)		
HB (Heidelberg)	66/11kV	Y	20/30	(1966)			20/30	(1966)		
NEL (North East Link)	66/22kV	Y	20/33	(2021)	20/33	(2021)				
NH (North Heidelberg)	66/22kV	Y	20/30	(1973)	20/30	(1973)	20/33	(2005)		
NS (North Essendon)	22/11kV	Y	12/18	(2017)	12/18	(2017)	12/18	(2017)		
NT (Newport)	66/22kV	Y	35/38	(1949)			35/38	(1949)		
PTN (Preston)	66/22kV	Y	20/33	(2019)	20/33	(2019)				
PV (Pascoe Vale)	66/11kV	Y	20/33	(2011)	20/33	(2012)	10/11	(1964)		
SBY (Sunbury)	66/22kV	Y	10/16	(2002)	20/33	(2018)	10/16	(2000)		
SHM (Sydenham)	66/22kV	Y	20/33	(2008)	20/33	(2010)				
ST (Somerton)	66/22kV	Y	20/33	(1985)	20/33	(1985)	20/33	(1996)		
TH (Tottenham)	66/22kV	Y	30/45	(1984)	30/45	(1984)				
TMA (Tullamarine)	66/22kV	Y	20/33	(2015)	20/33	(2015)				
YVE (Yarraville)	66/22kV	Y	20/33	(2013)	20/33	(2013)			10/16	(2000)

Table 4-2 lists the population and make/types for 66kV bushings and tap changers. The ABB type GSA 66kV bushings and MR tap changers are modern items of the HV plant that are fitted to new and

[3] A REFCL is installed.

some existing older transformers. Whereas the English Electric (EE), ABB type GOB and SECV type of 66kV bushings are original and fitted to older transformers. This is also the case for all tap changers with the exception of the MR tap changer.

Table 4-2: Power Transformer 66kV Bushing and Tap changer Information

Zone Substation	66kV Transformer Bushing Type				Tap Changer Type			
	1	2	3	4	1	2	3	4
AW (Airport West)	ABB GSA	ABB SEC	ABB GSA	ASEA	AEI	Ferranti	AEI	ABB UZF
BD (Broadmeadows)	ABB GSA	ABB GSA	ABB GSA	ABB GOB	Ferranti	Ferranti	Ferranti	ASEA
BMS (Broadmeadows South)	ABB GSA	ABB GSA			MR	MR		
BY (Braybrook)	ABB GSA	ABB GOB			AEI	ABB UZ		
CN (Coburg North)	ABB GSA	ABB GSA	ABB GOB		AEI	AEI	ASEA	
COO (Coolaroo)	ABB GOB	ABB GOB			MR	MR		
CS (Coburg South)	SECV L1079	SECV L1079			Ferranti	Ferranti		
EP (East Preston)	EE	ABB GOB	MIC SECV	EE	Fuller	ABB	EE	EE
EPN (East Preston)			ABB GSA				MR	
ES (Essendon)		ABB GSA	ABB GSA			MR	MR	
FE (Footscray East)	ABB GOB	EE			MR	AEI		
FF (Fairfield)	n/a	n/a	n/a		MR	MR	GEC/EE	
FT (Flemington)	EE	ASEA			Ferranti	Ferranti		
FW (Footscray West)	ABB GSA	ABB GSA	SECV 68/30A		AEI	AEI	Ferranti	
HB (Heidelberg)	EE		EE		Fuller		Fuller	
NEL (North East Link)	ABB GSA	ABB GSA			MR	MR		
NH (North Heidelberg)	SECV L1079	SECV L1079	ABB GOB		Ferranti	Ferranti	ABB	
NS (North Essendon)	n/a	n/a	n/a		MR	MR	MR	
NT (Newport)	MIC SECV		MIC SECV		EE		EE	
PTN (Preston)	ABB GSA	ABB GSA			MR	MR		
PV (Pascoe Vale)	ABB GSA	ABB GSA	MIC SECV		MR	MR	Fuller	
SBY (Sunbury)	ABB GOB	ABB GSA	ABB GOB		ABB	MR	ABB	
SHM (Sydenham)	ABB GOB	ABB GOB			ABB UZF	MR		
ST (Somerton)	MICAFIL UTXF	MICAFIL UTXF	ABB GOB		ASEA	ASEA	ABB UZF	
TH (Tottenham)	MICAFIL UTXF	MICAFIL UTXF			ASEA	ASEA		
TMA (Tullamarine)	ABB GSA	ABB GSA			MR	MR		
YVE (Yarraville)	ABB GSA	ABB GSA		ABB GOB	MR	MR		ABB UZP

Table 4-3 lists NER and Arc Suppression Coils details. There are 5 different manufacturers of Neutral Earth Resistors (NER) installed with the Zone Substations (ZSS). The oldest NER's are installed at ZSS NT and TH.

Table 4-3: NER, and ASC Information

Zone Substation	Voltage Ratio	NER	Manufacturer	Installation year
AW (Airport West)	66/22kV	Y	Fortress Systems	2010
BD (Broadmeadows)	66/22kV	Y	Fortress Systems	2010
BMS (Broadmeadows South)	66/22kV	Y	Fortress Systems	2014
BY (Braybrook)	66/22kV	Y	Fortress Systems	1999
CN (Coburg North)	66/22kV	Y	Fortress Systems	2019
COO (Coolaroo)	66/22kV	Y	MS Resistances	2006
COO (Coolaroo)	66/22kV	REFCL	Swedish Neutral	2023
CS (Coburg South)	66/22kV	Y	Fortress Systems	2004
EP (East Preston)	66/6.6kV	N	–	–
EPN (East Preston)	66/22kV	Y	Fortress Systems	2015
ES (Essendon)	66/11kV	Y	Fortress Systems	2008
FE (Footscray East)	66/22kV	Y	Fortress Systems	2010
FF (Fairfield)	22/6.6kV	Y	Fortress Systems	2010
FT (Flemington)	66/11kV	Y	Fortress Systems	2008
FW (Footscray West)	66/22kV	Y	OHMIC Controls	2003
HB (Heidelberg)	66/11kV	Y	Fortress Systems	2011
NEL (North East Link)	66/22kV	Y	Fortress Systems	2021
NH (North Heidelberg)	66/22kV	Y	Fortress Systems	2005
NS (North Essendon)	22/11kV	Y	Fortress Systems	2008
NT (Newport)	66/22kV	Y	Fortress Systems	1997
PTN (Preston)	66/22kV	Y	Fortress Systems	2019
PV (Pascoe Vale)	66/11kV	Y	Fortress Systems	2006
SBY (Sunbury)	66/22kV	Y	Fortress Systems	1999
SHM (Sydenham)	66/22kV	Y	Fortress Systems	2007
SHM (Sydenham)	66/22kV	ASC	EGE	2016
ST (Somerton)	66/22kV	Y	Fortress Systems	2010
TH (Tottenham)	66/22kV	Y	Fortress Systems	1997
TMA (Tullamarine)	66/22kV	Y	Fortress Systems	2015
YVE (Yarraville)	66/22kV	Y	Fortress Systems	2013

1.7.3 AGE PROFILE

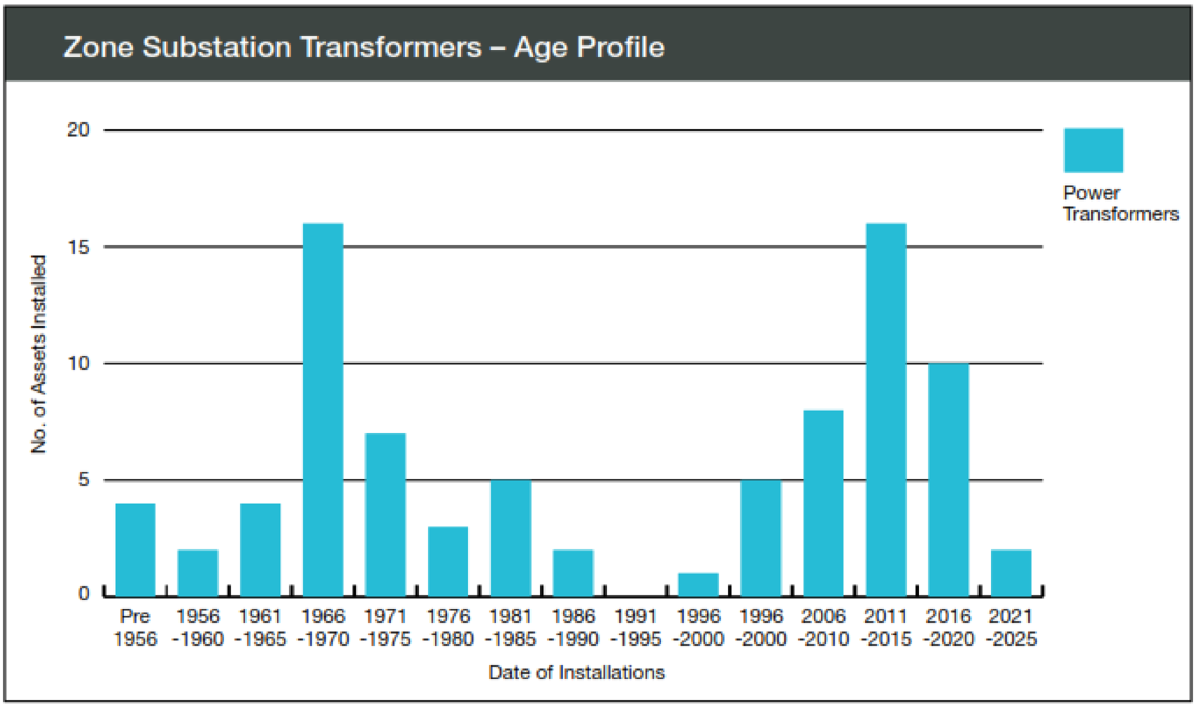
All transformers deteriorate with in-service time and thus it can be expected that the oldest units are likely to be in the poorest condition. There are many other factors that will contribute to the combination of data that is used to determine condition.

JEN operates 26 zone substations and 7 HV customer substations with JEN assets installed. These substations are equipped with 68 power transformers ranging in age from 1 to 73 years and consist of two main types:

- 66kV primary voltage and secondary voltages of 22kV, 11kV or 6.6kV, depending on their geographical location; and
- 22kV primary voltage and secondary voltages of 11kV or 6.6kV.

Figure 4–1 shows the power transformer age profile.

Figure 4–1: Power Transformers Age Profile



Of the various transformer age groups:

- Five transformers are over 60 years old, representing 7% of the total population (which will be prioritised for replacement using a condition and risk-based approach);
- 23 are over 50 years old, representing 34% of the total population (which will be prioritised for replacement using a condition and risk-based approach); and
- Five are between 40 and 50 years old, representing 7% of the total population (the ageing condition of which will be closely monitored as they approach and exceed 50 years).

1.7.4 RISK

This section includes information about transformer risk profiles involving the way that asset sub-class criticality is established, the risks posed by transformer failure (including the various failure types and their possible consequences), measures being introduced to manage asset risk, and a list of the various issues currently affecting zone substations.

This section provides information on the following:

- Asset class criticality score (sub-asset class level) for ranking of critical assets;
- Failure modes and effects analysis (RCM) for establishing maintenance programs;
- Current risks;
- CBRM for identifying assets approaching end of life;
- Existing controls;
- Asset spares;
- Contingency planning; and
- Future risks (involving other potential risk issues currently being managed).

1.7.4.1 *Summary of risk aspects for transformers*

- Criticality – being an asset of low volume (typically two or three per substation), high cost and long replacement lead time plus potential for a failure to leave up to 10,000 customers (including commercial and major industrial customers) without supply, transformers are classified as critical. There are only a few substations that are loaded beyond cyclic loading, with insufficient transfer capability and thus customers will be without supply should there be a transformer failure.
- Failure modes – winding and bushing insulation breakdown leading to total transformer failure are the most serious types of failures.
- Risk register - in a major failure of a transformer, the following risks have been identified:
    - HSE risk (tank rupture, oil leakage, flying fragments, possible fire);
    - Regulatory and Compliance risk (non-compliance on safety, penalties);
    - Financial risk (significant unplanned cost of replacement);
    - Operational risk (possible loss of customer supply if during peak load period);
    - [redacted]
    - An increased supply loss consequence at ZSS loaded above cyclic rating and with insufficient transfer capability at FT, HB, NS, SBY and SHM; and
    - Brand/Reputation/Stakeholder risk (possible large customer numbers off supply) at [redacted]

Existing controls are those detailed in the recommended condition monitoring and maintenance tasks documented in Section 4.1.8 (Life Cycle Management) and Section 4.1.4.2 (Spares), together with the initiation of replacement projects for assets determined to be at risk of major failure. Replacement prior to failure is the optimum control measure, as spare transformers are not available, and post-failure controls are not a justifiable option. Some 66kV bushing and tap changer spares are held. A transformer contingency plan (ELE AM PL 0010) details the risk mitigation measures should a transformer failure occur.

The condition of all in-service transformers will degrade over time due to insulation deterioration caused by heat, insulating medium contamination due to moisture and acidity, and environmental exposure. Therefore, transformer failure risk will increase in the future unless end-of-life units are replaced.

Data collection and analysis, as well as monitoring trends over time, will continue to provide a more accurate condition assessment. On-line condition monitoring will also be trialled to provide real-time data.

Emerging risks for power transformers include:

- Greater likelihood of winding/mechanical failure because of a through-fault on the HV distribution system due to degraded paper on end-of-life transformers;
- Specific types of power transformer 66kV bushings have failed on other electricity networks throughout Australia. Cyclic testing of 66kV bushings is performed to identify bushings that have some degree of moisture ingress, which can lead to bushing failure. Bushings with deteriorated insulation condition are replaced.
- Increasing the likelihood of transformer and tap changer plant failures will increase risks of outages. A review of transformer and tap changer spare stocks is a measure to mitigate these risks.
- Transformers with corrosive sulphur in oil, which can lead to rapid insulation system deterioration.

1.7.4.2 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). The results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets that have the potential to impact the achievement of operational objectives significantly. This is used to rank the importance of dissimilar sub-asset classes (e.g. transformers and buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures.

Major failures of transformers that cannot be repaired within 24 hours are only strictly considered as Strategic, if the substation loading is greater than transformer cyclic ratings and insufficient transfer capacity exists. However, due to the increased risk to the surrounding network and the costs and time required to replace a failed transformer, it is critical that contingency plans are in place for such events. (ELE AM PL 0010 – Zone Substation Transformer Contingency Plan).

[redacted]

Zone substation transformers are critical, low-volume assets. From an overall service perspective, two or three transformers typically form a zone substation and supply in excess of 10,000 customers.

The transformer has an asset criticality score of AC4 (High) due to operational and health and safety consequences associated with failures.

The criticality (importance) of a transformer is defined by:

- High replacement cost;
- Strategic impact on customer supply – (If the N-1 rating is exceeded and transfer capability is limited, then load shedding will be required if a transformer failure occurs);
- Long lead time for repair or replacement - procurement on a new transformer is typically 8 months;
- High consequence of failure – potential loss of supply, with the legal, reputational, and regulatory impacts and occupational health, safety and environmental issues; and

- Type of customers being supplied by the zone substation - Customers on life support require continuity and reliable supply at all times. All ZSSs are critical from a life support requirement perspective.

Below is a list of critical customers and total customer numbers supplied by each zone substation.

Table 4-4: JEN Major Customers as at 30 June 2022

Substation	Major customers	Total customers
AW	[redacted]	23,152
BD	[redacted]	13,580
BLT (at BLTS)*	[redacted]	1
BMS	[redacted]	4,464
BY	[redacted]	13,220
CN	[redacted]	21,980
COO	[redacted]	17,497
CS	[redacted]	21,722
EP	[redacted]	4,204
EPN	[redacted]	1,820
ES	[redacted]	17,176
FE	[redacted]	9,933
FF	[redacted]	6,765
FT	[redacted]	13,398
FW	[redacted]	14,042
HB	[redacted]	9,522
MAT*	[redacted]	1

Substation	Major customers	Total customers
NH	[redacted]	20,956
NEI*	[redacted]	1
NEL	[redacted]	1
NS	[redacted]	12,241
NT	[redacted]	13,200
PTN		11,636
PV	[redacted]	21,436
SBY	[redacted]	17,520
SHM	[redacted]	17,236
SSS*	[redacted]	1
ST	[redacted]	19,520
TH	[redacted]	3,181
TMA	[redacted]	2,701
VCO*	[redacted]	1
WGT*	[redacted]	1
YVE	[redacted]	8,485

* There are no JEN transformers installed at these sites.

It can be seen that the vast majority of zone substations supply major customers and together with life support requirements, all zone substations and major customer substations ([redacted]) are deemed critical.

The consequence of transformer failure is predominantly dependent on the capacity of the zone substation to supply customers after load transfer. Based on the JEN 2024 load demand forecast, utilising 10% PoE maximum demand forecast; some zone substations may have insufficient transfer capacity under single contingency condition should a transformer fail.

- At FT the station N-1 rating is 34.8MVA. The 10% PoE maximum demand is forecast to exceed the N-1 rating by summer 2025. The load transfer available to adjacent ZSS is 4.8MVA. Rotating load shedding may be necessary in the future.

- At HB the transformer N-1 cyclic rating is 29.2MVA. The 10% PoE maximum demand is forecast to reach the N-1 rating by 2027. The load transfer available to adjacent ZSS is 0.0MVA as HB is an island. Currently the transformers are being replaced and the new cyclic rating will increase to 38MVA. Once completed this project will alleviate load shedding event for N-1.
- At NS the station N-1 rating is 36.0MVA. The 10% PoE maximum demand is forecast to exceed the N-1 rating by summer 2025. The load transfer available to adjacent ZSS is10.3MVA. Rotational load shedding may be necessary in the future.
- At SBY the station N-1 rating is 38.0MVA. The 10% PoE maximum demand is forecast exceed the N-1 rating by summer 2025. The load transfer available to adjacent ZSS is 5.7MVA. Rotational load shedding may be necessary in the future.
- At SHM the station N-1 rating is 38.0MVA. The 10% maximum demand is forecast exceed the N-1 rating by summer 2025. The load transfer available to adjacent ZSS is 2.7MVA. Rotational load shedding may be necessary in the future.

For 66kV bushings, criticality (importance) is defined by:

- replacement cost;
- high strategic impact on customer supply – where demand exceeds N-1 capacity and transfer capability is limited, load shedding will be required in the event of a failure;
- long lead time for replacement (typically 4 months); and
- high safety and environmental consequence of failure (porcelain/metal projectiles, fire, oil spill).

Criticality is further assessed for individual transformers utilising a Condition Based Risk Model (CBRM). CBRM was introduced for transformers in 2014 and is utilised to predict condition into the future (represented by Health Index) and estimated Probability of Failure. These tools are utilised to indicate required changes to asset management plans, to develop asset investment plans using existing asset data and determine when end-of-life replacement will be required. Assets with a higher health index score are targeted for further analysis before imminent replacement. For further information on CBRM refer to Appendix K.

As the population of transformers continues to age there will be a number that are predicted to have deteriorated oil and paper insulation. There will be a need to increase maintenance activities and condition monitoring tests to manage the progressive replacement of these assets. Currently there are 5 transformers with a health index >7. In 10 years, there will be 20 transformers with the CBRM health index >7 if no planned replacement projects are undertaken.

1.7.4.3 *Spares*

As part of the criticality assessment, consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002). Adequate transformer component spares are maintained at the store located at Tullamarine.

Due to the costs and time required to replace a failed transformer, a contingency plan has been prepared to evaluate options for restoration to system normal conditions.

As documented in the Transformer Contingency Plan (ELE AM PL 0010), it is possible, should a long-term emergency situation exist, that a lightly loaded transformer could be relocated from one substation to another.

The loading and transformer ratings are reviewed annually to minimise the possibility of zone substations exceeding their N-1 ratings. Augmentation projects are initiated where justifiable. System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub-transmission line where line CBs have not been installed.

Primary plant assets are typically high cost assets and purchasing additional spares is not currently justified economically. Critical Spares Assessment Procedure (ELE-999-PR-RM-002) is used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I. When assets are retired from service, consideration is given to retaining components or entire assets as spares to service the existing fleet.

One spare 66/11kV transformer is held. This transformer is not in a good condition, therefore it is unable to be used as a spare. The transformer, stored at YVE will be scrapped in the future as it was supporting ZSS ES prior to the transformer upgrade. ZSS FW is currently being rebuilt and the three existing 66/22kV transformers will be retained on site as spares to support the network.

Table 4-5: Spare JEN Power Transformer

ZSS	Manufacturer	Age	Voltage Ratio (kV)	Rating (MVA)	Radiators	Condition
YVE	Wilson	56	66/11	20/27	Attached	Poor

A dedicated bushing hot room exists at the Tullamarine depot. All bushings were tested prior to being positioned within the hot room. If they failed electrical and/or visual tests, they were disposed of. It is important to cover the bushing stem with an oil-filled tube to avoid moisture ingress and mechanical damage.

1.7.4.4 *Failure Modes*

Transformers are generally reliable, and the risk of failure is considered to be low. However, as the condition of a transformer deteriorates, the risk of failure increases. The major risk associated with transformer operation has been identified as personnel safety and loss of transformation capacity in the event of potential failures. Transformer replacement is initiated when condition assessment and analysis indicates that the transformer is approaching end of life. Running transformer to failure increases the risk of a H&S incident and due to the long lead time (18 month delivery) there will be a greater impact on customer reliability and costs. The strategy of replacing a transformer that is in poor condition and at risk of failure delivers cost benefits and ensure reliability of supply to customers as well as mitigating H&S risk.

Typical transformer failure modes include:

- Winding/mechanical failure, usually due to a through-fault on the HV distribution system;
- Insulation failure due to lightning, over-voltages due to switching, water penetration, overloading (excessive temperatures), oil and aged paper degradation;
- Thermal failure due to a deteriorated or high resistance joint or connection, overloading, cooling system failure;
- External flashover between bushings or to any earthed structures, due to pollution, surface degradation, birds or animals; and
- Moisture ingress leading to bushing insulation failure.

Based on the known past history of serious transformer failures, there have been 1 in 15 years in the JEN and 3 in 40 years in the rest of Victoria. The Probability of Failure is estimated as Unlikely (it could occur sometime in the next 10 years).

The consequences resulting from these failure modes can include:

- Main tank, OLTC or bushing rupture possibly causing extensive oil contamination and/or fire;

- Associated explosion causing shattered airborne debris such as metal and porcelain;
- Loss of transformation capacity, with reduced availability to take outages on other in-service assets and with possible loss of supply to customers if a ZSS is loaded above cyclic ratings; and
- Additional loading on remaining in-service transformers creates an increased risk of cascade failure of the second unit and accelerated aging.

A table of transformer and 66kV bushing Condition Indices is available in Appendix E.

1.7.4.5 *CBRM Health and Risk Analysis*

The graphs below show the CBRM Health Indices for the population of transformers at the present time as well as in 5, 10, 15 and 20 years, if no replacements are made.

Figure 4–2: Transformer Health Indices at Year 0 (as at 2024)

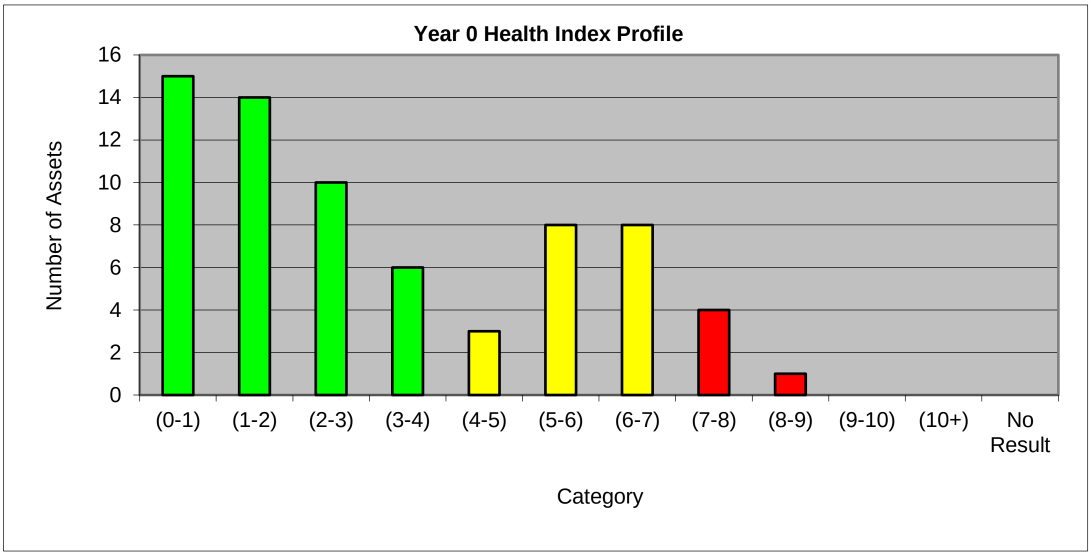


Figure 4–2 shows there are 5 transformers (as at 2024, Y0) in the red zone with Health Indices of >7 if no replacement projects take place, indicating an elevated probability of failure. These transformers are: [redacted] and [redacted]. The [redacted] transformer is now an emergency hot spare which will reduce the risk of failure of the No.1 or No.2 transformers. It will be replaced in 2025. The [redacted] transformers will be replaced in 2024.

Figure 4–3: Transformer Health Indices at Year 5 (as at 2024)

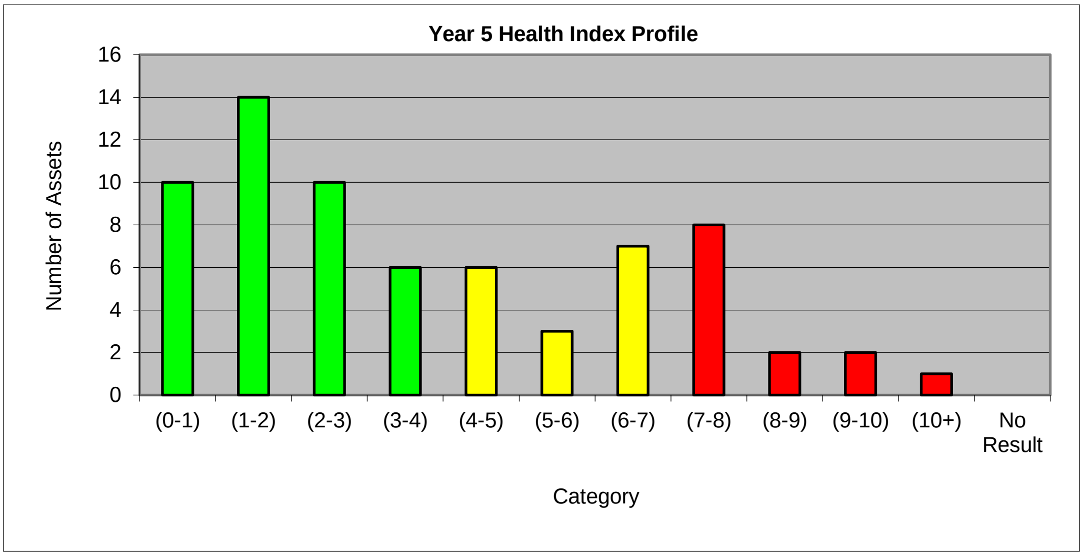


Figure 4–3 shows that there will be 13 transformers in the red zone, (HI>7) in 5 years if no replacement projects take place, indicating an elevated probability of failure. These transformers are: [redacted].

Figure 4–4: Transformer Health Indices at Year 10 (as at 2024)

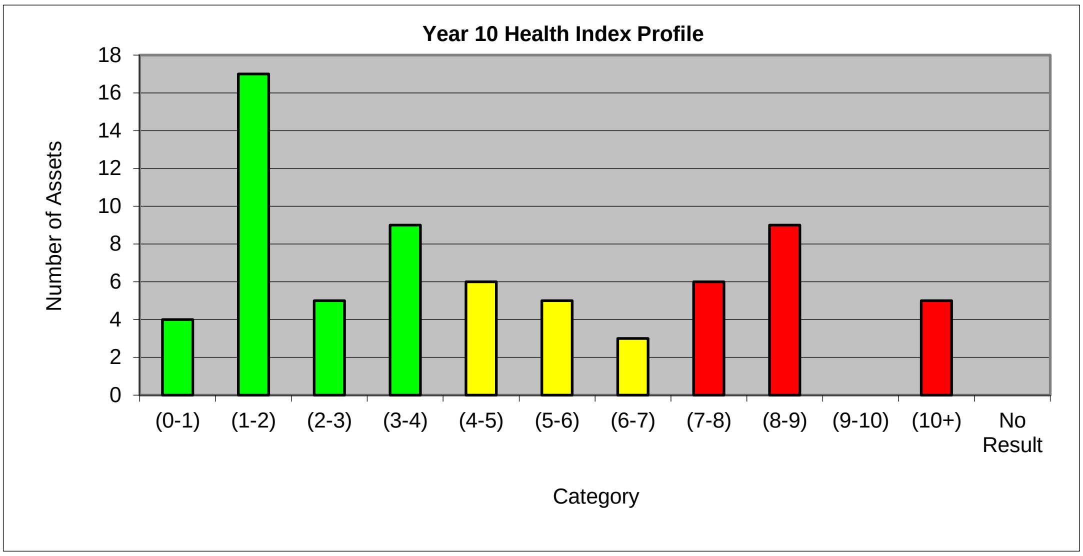


Figure 4–4 shows there will be 20 transformers in the red zone (HI>7) in 10 years if no replacement projects take place, indicating an elevated probability of failure.

Figure 4–5: Transformer Health Indices at Year 15 (as at 2024)

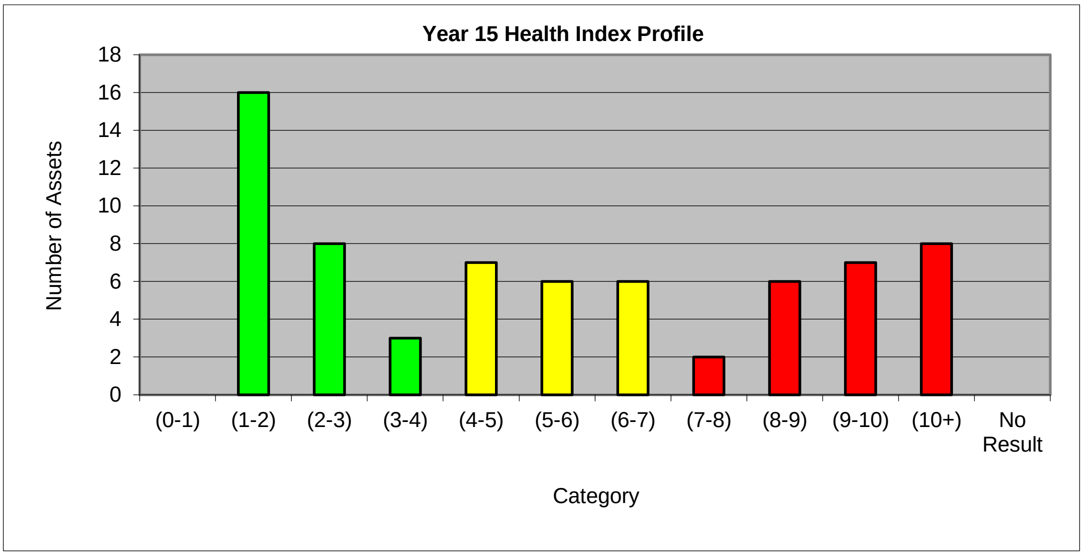


Figure 4–5 shows there will be 23 transformers in the red zone, (HI>7) in 15 years if no replacement projects take place, indicating an elevated probability of failure.

Figure 4–6: Transformer Health Indices at year 20 (as at 2024)

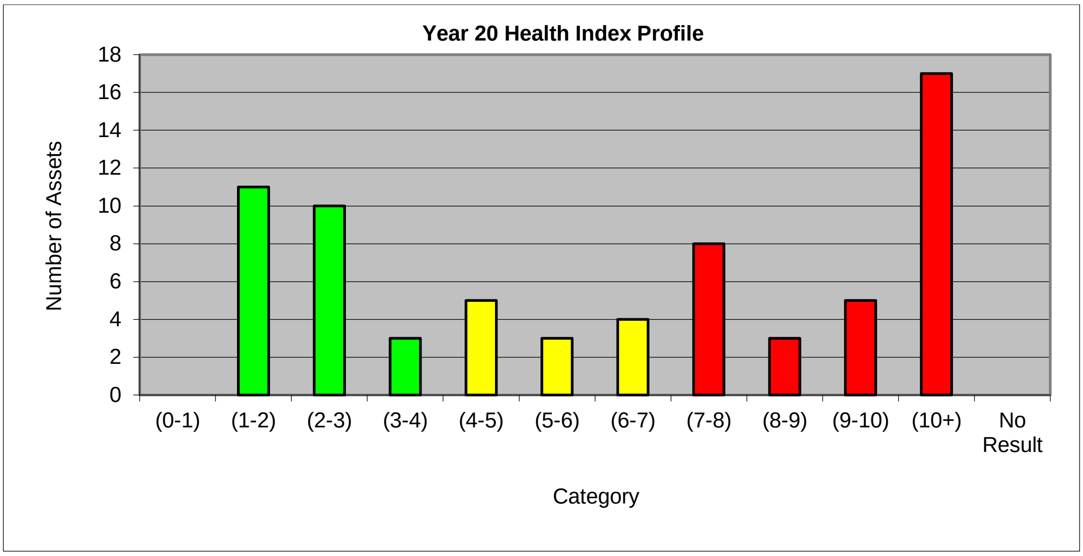
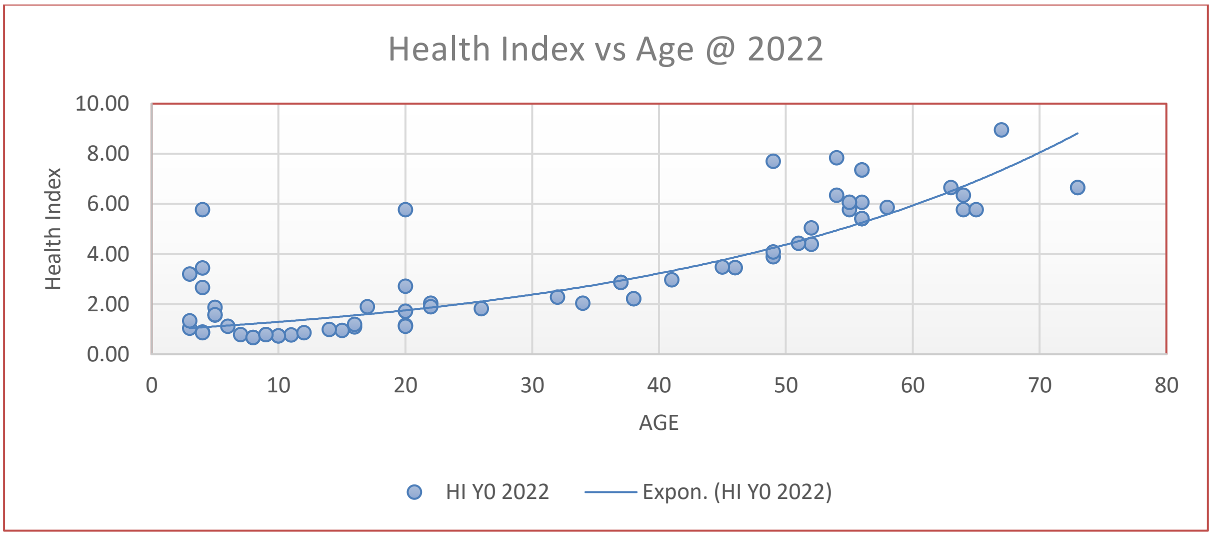


Figure 4–6 shows there will be 33 transformers in the red zone, (HI>7) in 20 years if no replacement projects take place, indicating an elevated probability of failure.

Multiple condition monitoring checks and tests are conducted to derive an overall condition assessment for each transformer. It is expected that the transformers in the poorest condition will also be among the oldest units. Figure 4–7 below illustrates the relationship between the CBRM Health Index and transformer age. There is a reasonable correlation between transformer age and high HI.

Figure 4–7: Correlation between Transformer Age and Health Index



1.7.4.6 *Further Information on CBRM*

The CBRM guide (ELE GU 0005 Condition Based Risk Management (CBRM) Application Guide) provides a summary of how JEN utilises CBRM to justify future replacement volumes for distribution and zone substation assets. It outlines the different inputs required and their associated outputs and how these outputs are interpreted.

1.7.4.7 *Existing Controls*

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in Section 4.1.8.3, together with initiation of replacement projects for assets determined to be in danger of major failure.

A summary of controls in place includes the following:

- Control room monitoring of loading, alarms for gas production, cooling system failure, tap changer anomalies, protection trips;
- Monthly inspections by operators, annual engineering audits;
- Scheduled maintenance on tap changers and transformer/ auxiliaries;
- Maintenance training and documented maintenance instructions;
- Scheduled condition monitoring tests of 66kV bushings, oil (DGA) & PDC/RVM and winding electrical tests;
- Refurbishment of gaskets, tap changers (Ferranti) and cooling auxiliaries;
- Oil regeneration and dry-outs;
- Corrective repairs of any defects;
- Loading assessments;
- Assessment of spares potential from retired units; and
- Condition based replacements.

1.7.5 PERFORMANCE FACTORS

Transformers are expected to provide their rated transformation function continuously for a lifetime of at least 50 years. Therefore, all factors contributing to maintaining satisfactory condition are essential to achieve this goal.

Specific power transformer performance measures (and condition monitoring) include the following:

- Oil condition: conductivity, quality, moisture in oil, acidity in oil, dissolved gas analysis, dielectric, interfacial tension, and copper sulphide presence;
- Bushing condition; and
- Paper condition: PDC/RVM, paper moisture, furan, and paper DP.

These performance measures are recorded in the Transformer Condition Index in Appendix E.

Other performance measures include the following assessments:

- On-load tap-changers;
- Winding temperature indicators;
- Noise reduction;
- Oil containment; and
- NER, REFCL and ASC.

Transformers are expected to operate continuously, providing its transformation capacity up to its rated values to meet the needs of customer demand and network operating variations, with acceptable risks relating to safety, environmental impact and economic costs.

The table below documents items that constitute performance requirements.

Table 4-6: Asset Performance Drivers

Driver	Risk/Opportunity Description	Consequence
Asset integrity, health, safety and environment, regulatory compliance	66kV bushing on ZS Transformers (known manufacturer defect in Victorian electricity networks)	Failure of bushing leading to customer supply issue and potential to damage a transformer beyond repair.
Asset integrity	Long lead time for repair/replacement of zone substation transformers	Risk to customer supply (approx. 10,000 customers impacted)
Asset integrity, health, safety and environment, regulatory compliance	Irreversible aging of zone substation transformers due to moisture content in the insulation	Increasing likelihood of failure of the asset leading to customers off supply, and increased risk to public, employee and contractor safety.
Asset integrity	Overloading of zone substation transformers	Reduce asset life of transformers causing premature replacement
Regulatory compliance, health, safety and environment	Reducing core clamping pressure in Zone substation transformer	Increasing levels of noise and reduced ability to withstand a through fault
Regulatory compliance, health, safety and environment	Non-compliance of older stations with noise regulations (particularly during peak load conditions)	Increasing levels of noise and customer complaints
Regulatory compliance, health, safety and environment	Typical ZS transformers contain 18,000 litres of oil and historically not all of these transformers have been suitably bunded	In the event of oil leaks, risk of non-compliance with environmental requirements.
Technological developments	Improved preventive moisture in insulation methodologies extending the life of the insulation	Improved asset maintenance (Trojan equipment)

1.7.5.1 *Performance Requirements and Targets*

Failure Prevention – avoiding catastrophic (unplanned outage of more than 24 hours) power transformer failures from occurring within zone substations. The target is zero failures per annum.

Factors affecting asset life

The design life of transformers is in accordance with Australian and international standards, and when constantly loaded to nameplate ratings, it is 30 years. When utilised within an electrical distribution network, loading varies and is usually less than nameplate ratings. Therefore, life can be expected to be greater than 30 years. Properly electrically protected, correctly loaded (within the various cyclic ratings), and adequately maintained, a transformer's life expectancy can exceed 50 years.

JEN has transformers in service that are more than 50 years old. However, in the past, JEN has had transformers fail earlier than 50 years. There is a low probability of failure for new to midlife transformers. As an example, the former No.1 transformer at zone substation EP was installed in 1960 and failed in service in 2002 (42 years of life).

An oil-filled transformer's life expectancy depends on the life of its insulation system, which is defined by a chemical process that primarily depends on temperature and time.

Other factors, such as the presence of oxygen and moisture, will accelerate the aging process.

Transformer performance is monitored to determine if the aging process is accelerating, as early corrective actions, such as oil conditioning, can control the various factors leading to insulation degradation. The mechanical condition of the transformer's paper insulation will usually determine when a transformer is at the end of life as this degradation is not reversible, and when the condition has reached a poor state (a DP of approximately 250), there is no economic corrective action to maintain the performance of the transformer. It is at this time that major refurbishment is not recommended, and replacement of the transformer will be required.

The CBRM tool calculates a transformer's expected life considering a range of condition factors.

Replacement plans

Although some transformers have continued to operate satisfactorily for over 50 years, a 50-year-old transformer is approaching the end of its practical life. Replacement plans are based on condition and reliability and not age alone.

Replacement plans should consider a variety of factors, such as capacity constraints and the condition of other equipment within the zone substation.

66kV Transformer Bushing Life Expectancy

The 66kV transformer bushing life expectancy is generally in line with the transformer's age. However, specific bushing types with incipient failure mechanisms built in during the manufacturing process have been identified as problematic (e.g., English Electric and SECV). Replacement programs have been initiated for these bushings.

Bushings (SRBP, RIP and OIP) are designed to withstand the electrical field strength produced in the insulation when any earthed material is present. As the strength of the electrical field increases, leakage paths may develop within the insulation. If the energy of the leakage path overcomes the dielectric strength of the insulation, it may puncture the insulation and allow the electrical energy to conduct to the nearest earthed material causing burning and arcing. Therefore, the insulation determines life expectancy and is electrically tested via Tan Delta.

1.7.5.2 *Condition Assessments*

A number of factors are assessed to determine whether individual transformers are highly likely to continue reliably performing their required function. Aspects such as age, condition, utilisation, effectiveness of risk controls, and actual performance are examined and analysed.

The results of condition monitoring and electrical tests are tabulated, and together with many other factors, are utilised in the CBRM model to provide a Health Index and risk value for individual and the population of transformers. Condition issues identified at Zone Substations are summarised below.

1.7.5.2.1 Transformers

Airport West (AW)

- The No.1 transformer started to produce gas (1ppm acetylene) and a high resistance connection was identified inside the selector switch compartment and repaired. Testing identified a high resistance connection internal to the main tank. During the bushing replacement and oil leak repairs, a loose connection was identified on a tapping lead and was repaired accordingly.
- No.1 & No.3 transformers neutral bushings have high DLA readings and are planned for replacement

- Also No.1 & No.3 transformers moisture in paper is high at 3.2% and IFT is poor.

Broadmeadows (BD)

- A project was completed in 2013/14 to replace the No.1, No.2, and No.3 transformer lid gaskets and 66kV bushings. Paper samples were taken from the HV bushings winding leads inside the transformers. The DP values of the No.1, No.2 and No.3 transformers are 292, 253 and 594, respectively, which means they are close to the end of life and need replacement.

Coburg North (CN)

- Monitoring of the No.2 transformer diverter switch oil leaks is continuing. Remedial work will be undertaken as required. It is anticipated that gasket replacement will be necessary.
- No.1 & No.2 transformers moisture in paper is high, and Interfacial Tension (IFT) is poor.
- In July 2019, it was identified that the station NER was discoloured and heat-damaged. The failure of the No.1 Cap Bank CB resulted in only two active phases. This caused an out-of-balance current of 190A to flow into the substation earth grid at the No.1 Cap Bank neutral, returning to the No.1 transformer via the NER. The NER, rated to carry only 10A of continuous current, suffered extensive heat damage as a result of prolonged exposure to 190A current. It is recommended for all NER installations that thermal alarms be installed and possible other design features also to be considered to monitor and alarms for neutral currents.

Coburg North (CN) and Flemington (FT)

- During 2022, an earthquake occurred in eastern Victoria which caused one transformer at CN and one transformer at FT to trip. There was no loss of supply to customers. Further investigation and corrective work are necessary to determine remedial action to prevent transformers tripping from Buchholz relay operation.

Coburg South (CS)

- During condition testing of the No.2 Transformer 66kV bushings, the test links in the box containing the matching transformers that drive the neutral displacement protection system had been left open and thus the capacitor taps on the condenser bushings were not earthed and found to be floating on all 3 phases. When the work crew disconnected the bushing capacitor taps, they noticed that the wires between the capacitor taps, and the matching transformer had been damaged. Although the bushings were subsequently tested, it is considered prudent to replace all 3 bushings.

Fairfield (FF)

- Paper samples taken from a winding lead on No.1, 2 & 3 transformers in 2013 and 2014 had a resultant DP of 220, 230 & 250 respectively. This indicated that the insulation in all three transformers had reached their end of life. Subsequently, No.1 and 2 transformers have been replaced.
- The No.3 transformer has a confirmed noise issue (with a significant margin up to 22dB(A)). The No.3 transformer has been retained as a hot spare and will be replaced in 2025. Sound enclosures on the No.1, No.2 and No.3 transformers will be installed.

Footscray West (FW)

- Acid levels and interfacial tension in No.3 transformer oil are fair and will be monitored and prioritised for oil re-generation.

- The No.3 transformer enclosure roof is currently being monitored for concrete cancer. Access restrictions are in place. In 2024, the No.1, No.2 and No.3 transformer will be replaced as part of the 22kV switchgear replacement in line with the new modular building standard.

Heidelberg (HB)

- A paper sample taken from No.1 transformer in 2013 had a resultant DP of 260 (close to end of life) and a paper moisture content of 4.9% (poor). This indicates that the insulation in the No.1 transformer is approaching the end of its life.
- Since the No.1 Transformer has a high moisture content (4.9% in paper), transformer overloads are not recommended. The International Council on Large Electrical Systems (CIGRE) working group report (A2.34 Guide for Transformer Maintenance, page 84) indicates that for moisture content in paper of 5%, the transformer should not operate within a temperature range above 100°C to 110°C to avoid a risk of bubble formation.
- No.1 and No.2 transformers have been replaced with the project completed in June 2024.

Newport (NT)

- Both transformers (constructed in 1949) were previously operating at a terminal station before being recommissioned at the ZSS. A similar transformer type in a neighbouring distribution business has experienced problems with the core earth.
- The main issue identified is the presence of an internal thermal fault (>400°C) which appears to have been present in both transformers since the year 2000. This is being managed by taking regular oil samples for Dissolved Gas Analysis (DGA).
- A paper sample from the No.1 transformer indicated a DP of 520. Transformer tests and paper samples are required for the No.3 transformer.
- The transformers have reached an age of 73 years. Condition monitoring will continue and offline electrical condition tests will be planned.

Pascoe Vale (PV)

- Oil test analysis diagnosed the No.3 transformer as having an internal thermal fault <300°C, which is currently stable. During 2011, in preparation for the No.1 and No.2 transformer replacement, the No.3 transformer was tested, and the high resistance internal connections were subsequently repaired. DGA monitoring is ongoing.

Sunbury (SBY)

- No.1 and No.3 transformer GOB (OIP) Bushings condition will continue to be monitored.

Yarraville (YVE)

- The No.4 transformer (construction year of 2000) has been experiencing elevated gas volumes with rising methane and ethane gas levels. This indicates the oil is getting hot in the transformer. The transformer is subject to an annual DGA, and the results have consistently identified the same gas signature. An internal inspection of the transformer was undertaken in 2011 that revealed an open circuit tertiary delta winding. DGA monitoring will continue to establish a trend.

1.7.5.2.2 Transformers Tap Changers, Conservator and 66kV Bushings

On load Transformer Tap Changer

All Ferranti tap changers need a half-life refurbishment involving replacement of worn components together with on-going maintenance training and documentation of maintenance procedures. This program is in progress.

Ferranti Onload Tap Changers have not been fitted with over pressure surge protection. Consideration will be given to introducing this protection.

Careful engineering assessment will be given to moisture in Ferranti OLTC's oil following a failure of a unit within another business.

For all other OLTC's where oil samples are required for condition assessment, a risk assessment will be prepared for taking oil samples with the asset in service or recommend de-energisation.

Installation of oil sampling points to OLTCs

To assess performance of On-load Tap-changers, annual oil samples and analysis is prudent. This condition monitoring task is ideal for early detection of emerging issues, over and above intrusive routine maintenance. However there are a few OLTC's that have not been fitted with oil sample valves by the manufacturer. A notional budget is required to install the oil sampling valves.

There is a risks of On-load Tap-change failures, which may be preventable by undertaking oil sampling and analysis. OLTC failures can be catastrophic, and in some circumstances the power transformer can be damaged beyond repair.

Transformer Conservators

Oil level indicators on both main transformer tanks conservators and tap changers conservators often exhibit oil leaks and poor visibility of the oil level through the sight glass, which require rectification and or replacement. Some of the older type of conservator oil level dial indicators occasionally seize and falsely indicate the oil level. Transformers have tripped for low oil levels. Maintenance tasks have been implemented to mitigate this risk.

Conservators fitted to transformer tap changers also need to be periodically cleaned internally during maintenance to remove deposits of carbon sludge and clean out of the oil level gauge glass. This activity will be included in the maintenance task list and the Standard Maintenance Instruction.

Transformer 66kV Bushings (English Electric, ABB type GOB, Hitachi/ABB GSA)

All English Electric 66kV bushings are considered to have high risk of failure due to moisture ingress and insulation degradation and are being progressively replaced. A similar emerging issue has been identified with the ABB GOB bushings (OIP). These bushings will be assessed due to the potential for a transformer oil fire if the bushing fails. Refer to Appendix E – Transformer Condition Health Index Tabulation for the test results and Table 4-7 Power Transformer 66kV Bushing and Tap changer Information for the location of the ABB GOB bushings.

Table 4-7: ABB type GOB 66kV Bushing Replacement Schedule

Station	Plant	Make	Model	Type	Comments
SBY	No.1 Transformer	ABB	TBA	OIP	Further testing, monitoring and replacement

The English Electric and ABB type GOB bushings have previously failed (for other businesses) and completely destroyed a transformer from the resulting fire.[4] The bushing condition will be revalidated, and an action plan prepared. These bushings and other GOB bushings will be replaced pending condition test results.

Table 4-8: English Electric 66kV Bushing Replacement Schedule

Station	Plant	Make	Model	Type	Comments
CN	No.3 Transformer	ABB	TBA	OIP	Further testing, monitoring and replacement completed in 2023
EP	No.1 Transformer	EE	TBA	RBP	Station planned to be re-built. No.1 now taken out of service
EP	No.4 Transformer	EE	TBA	RBP	Station planned to be re-built in 2027/2028
FT	No.1 Transformer	EE	BS 223	RBP	Capital project to replace in near future
FW	No.2 Transformer	EE	BD223	RBP	Becomes a spare transformer due to the modular switchgear replacement project
NT	No.1 Transformer	TBA	TBA	RBP	Plan retest or replacement

Prior to installing any replacement transformer bushings, electrical tests (DDF, PD, IR) will be undertaken to confirm their serviceability. Hitachi/ABB have demonstrated a concern with the construction of the GSA Bushings 72.5 kV bushing class. Multiple failures occurred in the local industry and the failure investigation indicated that there is no physical barrier as part of the bushing structure to prevent moisture ingress. Hitachi have been manufacturing this bushing since 1995, and indicate 0.1% of bushings delivered have been reported with defects/symptoms of a similar nature.

JEN has several transformers, each fitted with 3 off Hitachi/ABB GSA 72.5 kV class bushings. These bushings are a dry resin impregnated paper (RIP) design and used in an Oil-Air applications. The GSA bushings have been installed 2007.

Table 4-9: English Electric 66kV Bushing Replacement Schedule

Zone Substation	Transformers
AW (Airport West)	No.1 and No.3
BD (Broadmeadows)	No.1, No.2 and No.3
BMS (Broadmeadows South)	No.1 and No.2
BY (Braybrook)	No.1
CN (Coburg North)	No.1, No.2 and No.3
COO (Coolaroo)	No.1 and No.2
EPN (East Preston)	No.3
ES (Essendon)	No.2 and No.3
FE (Footscray East)	No.2
FW (Footscray West)	No.1
HB (Heidelberg)	No.1 and No.2
MAT (Melbourne Airport)	No.3

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NEL (North East Link)	No.1 and No.2
PTN (Preston)	No.1 and No.2
PV (Pascoe Vale)	No.1 and No.2
SBY (Sunbury)	No.2
SHM (Sydenham)	No.2
TMA (Tullamarine)	No.1 and No.2
YVE (Yarraville)	No.1 and No.2

In addition, there are 12 spare Hitachi /ABB GSA 72.5 kV class bushings located within the spare equipment store at the Tullamarine Depot.

The investigation report from Hitachi has presented a proved test methodology to detect the early sign of moisture ingress, which has been adopted by JEN. A test program has been proposed based on the risk level and criticality of the transformers affected. In addition, alternative bushing brands and types have been assessed and units will be purchased as strategic spares for GSA bushing replacement.

1.7.5.3 *Performance Analysis*

Performance of transformers is judged both by the continuity of reliable service and maintenance of acceptable condition such that failures in-service are unlikely.

At this point in time there are nine Zone Substations (BY, COO, CS, ES, FE, FT, HB, NS, SBY, SHM & YVE) that will exceed their N-1 cyclic ratings on a 10% PoE day. Operating transformers beyond their cyclic ratings is a risk which the business is prepared to take, balancing economics, accelerated ageing and probabilities of failure coupled with customer outage risks.

There have been no explosive/rupture/winding transformer failures since EP No.1 in 2002 and no 66kV bushing physical/explosive failures. Effective maintenance, condition monitoring and proactive condition based planned replacements have delivered this good performance.

Oil condition is recorded and monitored via the Transformer Condition Index. The condition index incorporates a traffic light system where dissolved gas analysis is used to obtain the following parameters: quality, moisture, acidity, dielectric, interfacial tension, furan and presence of copper sulphide. Refer to Appendix E for more information.

Important assumptions underpinning oil performance analysis include:

- Samples taken are free of water and other contaminants; and
- Results are continually monitored and actioned accordingly to prevent failure(s)

A power transformer contains a significant amount of paper insulation, and its condition varies throughout the transformer winding. Deterioration is at its highest where temperatures are highest, and this occurs within the transformer windings, which is not accessible. As a result, when a transformer is in service the condition within the winding can only be estimated.

Diagnostic testing and historical data are the only means available to determine the condition of the transformer deep within the insulation structure without dismantling the unit.

Important assumptions underpinning paper performance analysis include: PDC/RVM, paper moisture, furan and paper DP. Cyclic testing of 66kV bushings is performed, recorded and monitored. The aim is to identify bushings that present with high DLA readings because of moisture ingress, so replacement plans can be implemented prior to failure.

Important assumptions underpinning how transformer 66kV bushing performance are analysed include:

- Testing performed to obtain accurate test results; and
- Results continually updated and monitored so poor test results can be actioned accordingly to prevent failure(s).

The table below lists transformers in the Red zone based on condition monitoring tests. From the CBRM model, the Health Index (HI) column, indicated the condition HI=0 to 4 (Good/Fair), HI = 4 to 7 (Fair/Poor), HI = 7 to 10 (Poor to Bad). HI – 7 to 10, represent serious deterioration, that is, advanced degradation processes now reach the point that they threaten failure. In this condition, the probability of failure is significantly raised, and the rate of further degradation is likely to continue increasing. Zone Substations (ZSS) transformers at [redacted] and [redacted] have the highest HI indicating transformers are in poor condition. These transformers will be replaced during 2024-2025. All other transformers will continue to be monitored and mitigation will be put in place to treat their condition until replacement.

Table 4-10: Transformers with poor condition test results

ZSS	Transformer No.	Poor condition reason (listed in transformer condition index spreadsheet Appendix E)	Comparative CBRM HI
AW	1	Paper moisture high from PDC/RVM tests	4.43
AW	3	Paper moisture high from PDC/RVM tests. + IFT low	5.75
BD	1	Paper DP low from paper sample	7.36
BD	2	Paper DP low from paper sample	7.71
BD	4	Copper Sulphide detected in oil	2.73
CN	1	Paper moisture high from PDC/RVM tests + IFT low	5.23
CN	2	IFT low	5.49
CN	3	66kV Bushing condition emerging issue	2.28
COO	1	Copper Sulphide detected in oil	0.78
EP	2	Copper Sulphide detected in oil	0.93
FE	2	Moisture in paper high	5.78
[redacted]	[redacted]	[redacted]	[redacted]
FW	3	IFT low	4.43
[redacted]	[redacted]	[redacted]	[redacted]
NH	3	Copper Sulphide detected in oil	1.91
SBY	1	Copper Sulphide detected in oil	1.73
SBY	3	Copper Sulphide detected in oil	2.04

1.7.6 UTILISATION

1.7.6.1 *Power Transformer Utilisation – Limitations*

The rating of a zone substation is usually limited by the transformer thermal rating. As the transformer is the most expensive item of equipment in a zone substation it is standard practice for the transformer to be the limiting item of equipment. In most cases the summer rating is the predominate case for assessing zone substation limitations.

Almost all of the JEN zone substations can be controlled remotely and as such a 2-hour emergency rating or 10 minute emergency rating is available for modern transformers that were built in accordance with the current specification.

Transformer ratings are assessed individually, and each zone substation will have its own unique rating depending on the rating of the transformers and the degree of load balancing between them. Imbalance in transformer loading with respect to their ratings may also reduce the station rating.

1.7.6.2 *Power Transformer Utilisation – Ratings*

Zone substations are generally assigned four ratings:

Nominal Rating (N):	This is the peak demand based on a specified hypothetical load cycle in combination with a most onerous ambient temperature cycle.
Cyclic Rating (CR)	This is the permissible daily peak demand to which the transformer(s) may be subjected over a nominated period when a major plant item is out of service. (90 days has been used, being the practical repair period in the event of a major plant failure with no spares).
Limited Cyclic Rating (LCR)	This is the permissible peak demand to which the transformer(s) may be subjected over one daily load cycle, after which the transformer load must be reduced to its CR when a major plant item is out of service.
Two Hour Emergency Rating (2hr ER)	This is the permissible peak demand to which the transformer(s) may be subjected over 2 hours, after which the transformer load must be reduced to its LCR when a major plant item is out of service.

Under system normal operation, zone substations may be operated to the transformer name plate ratings. For a three-transformer station with 20/33MVA transformers, this means the station has a nominal maximum rating of 3 x 33 = 99MVA. However, depending on other station constraints (eg switchgear rated at 1250A – 47.6MVA@22kV) the station load may not be operated to the N rating.

Cyclic ratings can be used for short periods of time as the load is not constant over time. The cyclic rating is higher than the nameplate rating which allows the transformers to be loaded above the nameplate rating for a period of time. The higher the assigned cyclic rating, the shorter the time the transformers can be operated before exceeding safe core temperatures. Some loss of life occurs when the cyclic ratings are used.

The ratings are based on the formulae and temperature/life curve derived from AS 60076-7 with the following assumptions:

Top Oil Temperature Limit	= 105ºC
Hot Spot Temperature Limit	= 140ºC
Maximum Current Limit (cyclic)	= 1.5 times rated current
Maximum Current Limit (limited cyclic)	= 1.65 times rated current
Daily Loss of Life (cyclic)	= 0.03%
Daily Loss of Life (limited cyclic)	= 0.12%

The above ratings apply to newer transformers and caution must be exercised when considering ratings of transformers that old or in known poor condition. Older transformers were manufactured to different specifications and overload temperature rise tests may not have been conducted. It cannot be assumed that transformer cyclic rating is just a multiple of its nameplate rating. Cyclic ratings can only be proven by thermal testing to determine the temperature rise and temperature gradient of the transformer internal configuration.

As an example, if a transformer is loaded at its cyclic rating, each 24 hours of such loading will account for 0.03% of loss of transformer life, ie, the transformer will have a life of about 10 years. Similarly, if a transformer is loaded at its limited cyclic rating, each 24 hours of such loading will account for 0.12% of loss of transformer life, ie, the transformer will have a life of about 2.5 years.

In applying these ratings, the philosophy has been that a zone substation can be loaded up to its (N-1) limited cyclic rating provided there was adequate transfer capability to reduce the load on the station to its cyclic rating within 24 hours.

In most contingency situations, however, it is possible to effect load transfers within 2 hours. Hence, the concept of “2-hour emergency rating” has been introduced and applied at critically loaded zone substations to defer capital expenditure.

With the implementation of remote monitoring and control schemes at zone substations and remote switching on the distribution network, shorter time ratings (10 minutes) can be introduced provided procedures are put in place to minimise risk of damage to plant.

10 min Emergency Rating: (N-1) 10 min ER	This is the permissible peak demand to which the zone sub-station may be subjected over a ten-minute period, due to an emergency transformer outage. After which the transformer load must be reduced to its (N-1) LCR and further reduced to below its (N-1) CR within 24 hours. These will only be applied to newer transformers

1.7.6.3 *Power Transformer Utilisation – Overload Ratings*

Overload ratings of stations may be available if remote transformer temperature monitoring is installed at a zone substation. The Dynamic Ratings, Monitoring, Control and Communications (DRMCC) relay already fitted to a large number of transformers provides remote transformer temperature data to the Control Room where this feature has been enabled.

Unlike the cyclic ratings which take advantage of the rise and fall of the load curve on a cyclic basis and the emergency ratings which utilise a theoretical model to derive a current rating, the overload rating utilises the precise operating temperature and the maximum temperature limitation of the transformer.

Given that the cyclic ratings are based on high ambient temperatures, a contingency during cooler conditions means that potentially higher ratings could be obtained. This is where the overload rating becomes useful with a direct reading of transformer oil temperature.

Some adjustment of the temperature reading would need to be made to account for the fact that the transducers will not be monitoring the ‘hot spot’ of the transformer.

Note: Lower Hot Spot temperatures (eg 110 ºC – 130 ºC) should be employed for transformers with known high moisture levels as gas bubbles are known to form with consequential increased risk of insulating oil breakdown.

1.7.6.4 *Power Transformer Utilisation – Contingency Management*

In the event of a fault anywhere between the sub-transmission busbar and the distribution busbars, a transformer can be completely isolated by the automatic protection tripping of the remote 66kV line CB, the 66kV bus tie CB and the 22/11/6.6kV transformer CB, without loss of supply to the 22/11/6.6kV buses. The remaining transformer(s) will carry the station load until operators arrive to assess the situation.

A zone substation with full transformer switching available may be operated at the (N-1) 2-hour emergency rating of the zone substation with one transformer off supply without risk of damage. Within two hours the load must be transferred away or shed on a cyclic basis to reduce the station to the (N-1) LCR. In the case of a long-term fault, any load in excess of the cyclic rating should be reduced within 24 hours either by further transfers to adjacent stations or increased shedding on a cyclic basis.

The station may be loaded to a (N-1) 10-minute rating provided that an automatic load shedding scheme is in place to transfer the load away rapidly. Stations operating above the 2-hour rating without an automatic load shedding scheme will need to have feeders shed load in order to protect the transformers.

Auto-reclose on the sub-transmission lines reduces the risk of this situation considerably given that a trip of a sub-transmission line is the most probable contingency.

Contingency	Full Transformer Switching Without Line CBs
Line Fault	A line fault results in loss of a transformer; hence, shedding some load due to overloading may be necessary.
Contingency	**Full Transformer Switching with Line CBs**
Line Fault	A line fault does not result in loss of a transformer, hence no loss of supply to customers.
Contingency	**Full Transformer Switching Without Line CBs but with Motor Operated Disconnectors (MOD) installed**
Line fault	A line fault results in loss of a transformer initially, but operation of MOD allows transformer to be reconnected after faulted line is isolated; hence, shedding some load due to overloading may be necessary then quickly restored.
Transformer Fault	A transformer fault does not result in total loss of supply to customers. However, shedding some load due to overloading may be necessary.

1.7.6.5 *Power Transformer Utilisation – Transformer Capacity*

The current standard transformer rating is 20/33MVA based on:

20MVA: ONAN (oil natural, air natural)

33MVA: OFAF (oil forced (oil pumps), air forced (fans))

These ratings are further increased to give the cyclic and emergency ratings as above by application of guidelines in Australian Standards 60076-7, Guide to Loading of Oil immersed Transformers.

This generally results in summer CR, LCR and 2hr ER of *(for newer transformers only):*

CR 42MVA

LCR 45MVA

2hr ER 49.5MVA

This is assigned on a station-by-station basis. Other factors such as *load profile at the substation and* other equipment limitations in the zone substation can reduce these figures.

Older transformers need to be assessed individually taking into account temperature rise figures, cooling and oil flow design and performance to establish cyclic ratings. Refer to Appendix F for individual substation cyclic ratings.

1.7.7 CONTROL EFFECTIVENESS

Controls employed are identified in Section 4.1.4.6 and condition-based replacements completed are listed in Section 4.1.8.5. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table:

Table 4-11: Effectiveness of Existing Controls

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Transformer or bushing explosive rupture failure – people safety and or environment impact	Asset Management strategy applied. Replacement transformer & bushing projects completed and further identified	Nil
Regulatory & compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement transformer & bushing projects completed	Nil
Financial	Rectification of failures results in significant (>$1M) unplanned cost	Asset Management strategy applied. Replacement transformer & bushing projects completed	Nil (Minor repairs at AW, EP)
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement transformer & bushing projects completed	Nil Majority (but not all) ZSS operate less than N-1

It can be seen that the controls employed, which are the focus of this ACS document, judged by historical performance, confirms that these controls have been effective.

1.7.8 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The preferred asset lifecycle management option involves condition monitoring and preventive maintenance, with the aim of achieving at least 50 years of asset life before replacement (although a transformer may be replaced earlier if increased capacity or capacity requirements dictate), given that power transformers typically:

- cost approximately $2.4 million (indicative only based on an estimate for replacing a single transformer with no other works undertaken) to replace for a contained failure; and
- incur low operating expenditures due to their high reliability and low-maintenance requirements.

There are 3 feasible lifecycle management options:

- Condition monitoring and preventive/corrective maintenance, with condition and risk-based replacement. By managing the transformer load within its design parameters and regular scheduled maintenance, a transformer's life expectancy can exceed 50 years. Cyclic testing of 66kV bushings is performed to identify bushings that have some degree of moisture ingress which can lead to bushing failure, and onload tap changer and cooling system maintenance are also performed.
- Preventive/corrective maintenance with fixed, age-based replacement (irrespective of condition). This option is not considered to be cost-effective, as condition monitoring, preventive maintenance, diagnostics and CBRM modelling can be employed to achieve more optimum timing for replacement; and
- Preventive/corrective maintenance and run-to-failure replacement. This is not a realistic option due to the criticality of the assets (power transformers), the long lead-time for replacement, and the significant cost of carrying system spares. A few zone substations are currently operating above N-1 and run-to-failure would directly result in widespread and frequent supply interruptions for up to eight months until a replacement transformer is procured and installed.

1.7.8.1 *Lifecycle management*

The current asset strategy involving adequate monitoring and maintenance is intended to extend transformer life beyond 50 years.

The decision to replace a 66kV transformer bushing is based on an engineering assessment of the DLA test result. The DLA result is assessed using the Tan Delta Result Card. Cyclic testing of 66kV transformer bushings is performed every 5 years to measure the Dielectric Dissipation Factor (DDF) and to identify bushings that have poor insulation condition which is typically caused by moisture ingress.

1.7.8.2 *Creation*

Working assets in power transformers are effectively created via acquisition, or to meet load demands, or asset replacements.

The specifications with embedded standards employed to enable this asset to meet requirements include:

- Australian and international standards for transformer and substation design;
- Zone substation transformer 66/22 and 66/11 kV specification;
- Zone substation 22/11/6.6 kV power transformer specification;
- Zone substation Primary Plant Design Manual JEN ST 0610; and
- Period contracts for procurement.

The standard types and acquisition triggers for power transformers include:

- As part of a new zone substation development;
- As a part of an existing zone substation capacity upgrade;
- As part of a company take over with similar electrical network; and
- To replace old transformers that have reached end-of-life.

With a lead-time (from the submission of a purchase order to installation) of approximately 8 months, the transformers required due to the first trigger are currently sourced as part of a turn-key project for the entire substation or from period supply contracts. The transformers required due to the second and fourth triggers are sourced from period supply contracts.

To reduce associated design, construction and installation costs, power transformers have been standardised to two main types; 66/22 kV and 66/11 kV, with the exception of the zone substations at East Preston (EP) at 66/6.6kV, Fairfield (FF) at 22/6.6kV, and North Essendon (NS) at 22/11kV.

Planning for conversion of the EP transformers to 66/22kV is currently being undertaken due to capacity constraints.

A standard design for 22/11/6.6kV transformers was developed for transformer replacements at Fairfield (FF) and North Essendon (NS), as the sub transmission voltage at these zone substations will remain at 22kV for the foreseeable future.

1.7.8.3 *Asset Operation and Maintenance*

This section provides information about the asset maintenance program, including inspection and testing, preventive maintenance, and reactive and corrective maintenance.

The current asset maintenance program involves:

- Monthly inspection conducted by operational employees;
- Annual inspection conducted by engineering staff;
- Reactive and corrective maintenance;
- Preventive maintenance - time and condition based; and
- Time based condition monitoring.

The level of expenditure required for these four activities will be monitored to ensure it is adequate to maintain transformer performance at the expected levels over the transformer life.

1) Inspection

Inspections of ZSS are conducted monthly by operating personnel, and annual engineering audits are conducted by the Primary Plant Engineers.

Transformer inspection activities undertaken during these site visits include checking for general cleanliness, oil levels, oil leaks, corrosion of tank/cooler/conservator, tank distortion, broken porcelain; tracking on bushings and surge arresters; observing hot spot and top oil temperature indication, operation of auxiliary equipment such as the transformer cooling systems and any unusual noise.

Bushings are closely inspected during class 4 (see Appendix 7.1 for class details) transformer maintenance every 4-6 years. As per the Standard Maintenance Instruction (SMI) the bushings are inspected for physical damage, oil level checked (if applicable), terminations inspected, bushing caps inspected and bushings cleaned accordingly.

2) Reactive and corrective maintenance

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified faults (or both), resulting in the repair of:

- Oil leaks (bushings, tank gaskets, radiators, oil gauges);
- Transformers (replace bushings, repair/replace rusted radiators, repair conservator oil level indicators);
- OLTCs (mechanism failure and diverter switch contact replacement); and

- Auxiliary equipment (defective temperature indicators, fans, and pumps).

Assessment of condition monitoring results can generate tasks such as:

- Regenerate oil to reduce acid levels;
- Oil processing to reduce moisture. Transformer main tank oil dry out (Using the Trojan) on an as needs basis; and
- Excessive DGA readings necessitating physical inspections and repair of high resistance connections.

3) Preventive maintenance

Transformers and OLTCs are scheduled for preventive maintenance based on:

- Operational duty (the number of tap-changer operations), or
- A maximum time interval of 6 years.

Standard Maintenance Instructions document the details of these maintenance activities.

4) Condition-based monitoring

Condition-based monitoring programs involve:

- Annual oil sampling and testing;
- Annual dissolved gas analysis;
- Degree of polymerisation value is estimated form annual oil samples. However PDC/RVM measurement and paper samples are planned as the need arises;
- Annual infra-red thermal imaging; and
- High voltage bushing monitoring (DDF) at 5 yearly intervals.

The CBRM model is updated with results to evaluate current condition and predict condition into the future. For more information about these monitoring programs, see Appendix D.

1.7.8.4 *Zone Substation Transformer Condition Monitoring Health Index*

A transformer's operating life is difficult to directly determine due to different variables, including its fault history, load, operating environment, and age. The Transformer Condition Monitoring Index (see Appendix E) contains condition data used to conduct an engineering assessment of a transformer's condition and potential for life extension. This data is also applied in the CBRM model. Refer to Appendix K.

The Condition Monitoring Index is:

- Maintained to monitor transformers, schedule testing, and determine an end-of-life;
- Continually updated with information about Polarisation and Depolarisation Current (PDC), Recovery Voltage Measurements (RVM), DGA and electrical test results; and
- Considers the results of the bushing DDF.

1.7.8.5 *Asset Replacement/Disposal*

Replacement of zone substation transformers prior to failure is only considered when all efficient cost maintenance and life extension options have been considered and condition monitoring has indicated that the transformer is likely to fail electrically, thermally or mechanically. The deterioration trend cannot be halted or reversed. The CBRM modelling supports the planned replacement in the capital replacement program, which has been optimised according to acceptable risk criteria to meet performance targets. From Table 4-8, Zone Substations transformers at [redacted] have the highest HI indicating transformers are in poor condition. The [redacted] transformers will be replaced in 2024 and the [redacted] transformer will be replaced in 2025. The [redacted] transformers will continue to be monitored and mitigation will be put in place to treat their condition until replacement.

Planned power transformer replacement is determined and prioritised based on ongoing testing results. However, resource constraints and other network requirements (such as capacity constraints) must also be considered.

If a 66kV transformer bushing presents a poor Tan Delta results the bushing will be replaced within 3 months. During this time, the bushing condition will be assessed to determine if it is safe for the transformer to remain in-service. Otherwise, bushing results are recorded and replacement prioritised accordingly.

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how JEN prioritises and optimises its investments.

1.7.8.6 *Historical capital replacement*

Table 4-12 lists information about historical transformer replacements for the period 2002 to 2024.

Table 4-12: Transformer Replacement History from 2002 to 2024

Year	Qty.	Transformer	Reason for Replacement
2002	1	EP No.1	Transformer winding insulation failure resulting from an external feeder fault. Poor DP of 300.
2006	1	EP No.2	Replaced due to poor condition of winding insulation.
2009	1	YTS* No.2	No.2 transformer removed from service due to poor condition of HV bushings as a result of cooling system failure.
2012	2	PV No.1 & No.2	No.1 & No.2 transformers were replaced due to poor condition and to meet future load demand.
2014	2	YTS* No.1 and No.3B	YVE zone substation was built with two new 20/33 MVA transformers to replace the two old transformers at YTS zone substation whose winding insulation was in poor condition.
2017	3	NS No.1, 2 & 3	Transformers were replaced due to their poor condition
2018	1	SBY No.2	Transformers were replaced due to their poor condition
2020	2	FF No.1 & No.2	Transformers were replaced due to their poor condition
2020	2	ES No.1 & No.2	Transformers were replaced due to their poor condition
2020	4	P No.1 & No.2 plus reactor transformers	Transformers were replaced due to their poor condition and distribution voltage conversion from 6.6kV to 22kV. A new ZSS PTN was created on the same site as ex ZSS P.

* The Yarraville Terminal Station (YTS) has been replaced by the Yarraville Zone Substation (YVE).

The No.1 and 3 transformers at ZSS HB are currently being replaced, and project completion is expected in 2024. Also, the No.1 transformer at ZSS EP is planned to be shut down as part of the 6.6kV to 22kV voltage conversion program, and the load will be supplied by the EPN No.2 66/22kV transformer anticipated in 2025.

Table 4-13 lists information about historical transformer bushing replacements for the period 2002 to 2022.

Table 4-13: 66kV Bushing Replacement History from 2002 to 2024

Year	Quantity	Transformer	Reason for Replacement
2013	3	AW No.1	Poor DDF results
2014	3	AW No.3	Poor DDF results
2014	3	AW No.3	Poor DDF results
2014	3	BY No.1	Poor DDF results
2014	3	BD No.1	Poor DDF results
2013	3	BD No.2	Poor DDF results
2014	3	BD No. 3	Poor DDF results
2013	3	CN No.1	Poor DDF results
2013	3	CN No.2	Poor DDF results
2014	3	ES No.1	Poor DDF results
2016	3	FW No. 1	Poor DDF results
2017	1	SBY No.2	Poor DDF results

Table 4-14 lists proposed replacements for the next 10 years from 2024 to 2033

Table 4-14: Proposed Transformer Replacements from 2024 to 2033

Transformer	Estimated Replacement Timeframe	Reasons for Replacement	Comments
FF No.3	2025	Poor DP, Fair oil quality & Noise level issues	Prediction using CBRM. Scope of work and Business Case is yet to be prepared.
FW No.1, No.2 and No.3	2025	Condition TBA	Replacement to line up with modular switchroom and avoid rework
HB No.1 and No.3	2024	Poor DP, Fair oil quality, high paper moisture	Completed
EP No.1 No.3 and No.4	2024 2029	Condition	Retirement during voltage conversion project. No.1 transformer retired 2024
BD No.1 and No.2	2033	Poor DP	Paper sample and full transformer testing to continue. One transformer planned for replacement.
BD No.3	2033	Condition	Prediction using CBRM. No.3 transformer replacement can considered for later replacement in 10 years, pending station loading increases.

Transformer	Estimated Replacement Timeframe	Reasons for Replacement	Comments
			Scheduled aligned to 22kV CB replacement. Modular switchrooms.
AW and AW No.1 and No.3	2033	Fair oil quality, high moisture	Paper sample and full transformer testing to continue. Prediction using CBRM. Scheduled aligned to 22kV CB replacement. Modular switchrooms.
NT No.1 and No.3	2033	Poor DP, fair oil quality, high moisture.	Prediction using CBRM. Paper sample and full transformer testing to continue
PV No.3	2032	Poor DP	Prediction using CBRM. Paper sample and full transformer testing to continue.
CN No.1 and No.2	2029	Poor DP, fair oil quality, high moisture	Paper sample and full transformer testing to continue. Prediction using CBRM. Consider replacement to line up with switchgear replacement, modular switchroom. Scheduled aligned to 22kV CB replacement. Modular switchrooms
BY No.1	2033	Condition	Prediction using CBRM.

Table 4-15 lists proposed bushing replacements for the next 10 years from 2024 to 2033

Table 4-15: Proposed 66kV Bushing Replacements from 2024 to 2033

Transformer	Estimated Replacement Timeframe	Reasons for Replacement	Comments
AW No.1 and No.2	2028	Poor Tan Delta results	Replace with ABB GSA-OA Transformer Neutral bushings.
CS No.2	2025	Transformer in service with 66kV bushing capacitor tap unearthed	Capacitor tap left unearthed for approximately 12 months.
FT No.1	2028	English Electric RBP bushings	Replace with ABB GSA-OA.
PV No.3	2025	Poor Tan Delta results	Red, White and Blue Phase Bushings.
FW No.2	2025	Poor Tan Delta results	Transformer to be replaced as part of the station rebuild.
NT No.1	2025	Poor Tan Delta results	Blue Phase Bushings, Red, White are also poor.
EP No.1	2024	Poor Tan Delta results	Red & blue phase. Replacement during voltage conversion project. Transformer has been retired.
HB No.1 and No.2	2024	Poor Tan Delta results	Construction in progress to replace transformers. Transformers have been replaced.
Various Transformers fitted with Type GOB bushings	2030/2031	Poor performance history of OIP bushings external to JEN	

Typically, when power transformers are retired or replaced, they are drained of approximately 18,000 litres of oil, which is tested and disposed (recycled) of separately. In order for the transformer to be fit for transportation, a certificate must be obtained to ensure the transformer is free of PCB.

Before disposal, the transformer is assessed for retainable spare parts. If similar plant exists, all applicable parts (bushings, tap-changer parts, conservator gauges etc.) will be tested and retained as spares.

Paper samples are tested at the time of disposal to provide information about transformer ageing for reference purposes.

Transformer 66kV bushings are tested for PCB contamination and disposed of in line with Waste Management Procedure (JEM HSE PR 0016).

1.7.8.7 *Transformer Future Improvements*

JEN's technology strategy involves investigating new technologies to maintain network reliability, plant and employee safety, reduce costs and currently involves the following:

- Future improvement to the management of earthing systems will be to complete the implementation of the ASC system for resonant earthing at all high-exposure bushfire zone substations. In addition, JEN plans to further install ASC systems similar to the unit installed at ZSS SHM to enhance public safety. The next installation is planned for ZSS FW. ASC installations will improve public safety and reduce the likelihood and consequence of arc flash exposure. The likelihood of a single-phase fault developing into a 3 phase fault will be better controlled by an ASC. It is envisaged that all JEN ZSS sites will ultimately be installed with resonant earthing.

- **The Wilson 'Dynamic Rating, Monitoring, Control and Communications** (DRMCC)' system has substantially improved transformer control functionality and provided greater flexibility for parallel transformer operation. The option of retrofitting DRMCC to existing transformers has been evaluated and is being implemented in conjunction with certain zone substation augmentation projects. The cost of this functionality is minor when compared to the total augmentation cost. In addition, the use of DRMCC in conjunction with SCADA provides the opportunity for online monitoring of winding, oil and bushing condition in real-time.

- **Due to increasing environmental sensitivity**, a new option to replace mineral oil in existing transformers with a synthetic, high-temperature fluid (called FR3) is now available. The industry is still evaluating and testing this fluid. FR3 is almost five times more expensive than mineral oil, but depending on how the EPA classifies it, its use could eliminate the need for oil containment. It could also reduce the fire risk associated with a transformer fault. This should result in lower installation costs, however a full economic evaluation will be carried out before FR3 is adopted.

- **Vacuum interrupter type 'in-tank' tap-changers** are now being specified for transformers. These tap-changers use vacuum interrupters for the diverter switches, so no switching of current occurs in oil. This means there is no accumulation of arcing products during normal switching operations associated with the tap-changer, enabling the installation of the entire tap-changer in the tank with the transformer core and coils. This results in a cheaper transformer construction cost and the elimination of the need for routine tap-changer maintenance, reducing a transformer's life cycle cost.

- **On-line monitoring of the oil/insulation system condition** of the older population of transformers with poor condition and high risk was identified using the CBRM model. Utilising the functionality of existing DRMCC installations, online modules can be purchased, and control room protocols can be established to monitor transformer condition 24/7. The interface modules include:

  - DGA;
  - 66kV bushing PD; and
  - OLTC tap changer temperature monitoring.

- Online monitoring systems to determine a suitable standard for JEN and identify which asset would benefit from this initiative is planned.

- **Fibre optic sensors** for accurate monitoring of transformer hot spot will be employed for all future transformers.

- The Victorian Electricity Supply Industry Group allows sharing of defect information concerning transformers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote the efficiency and reliability of substation management.

- **An innovative water filter ([redacted])** to prevent petrochemicals (transformer oil) loss into the environment has been trialled and installed at NEL and HB. Early assessment of the [redacted] performance is promising, however a primary particle filter must be installed within to prevent the [redacted] unit blocking up and the bunds filling with water. These particle filters will need to be cleaned regularly. It is recommended that all existing and new transformer installations are fitted with a [redacted] system.

- **Bushing testing:** Update the bushing DLA test plan to include Swept Frequency Response Analysis.
- For all OLTCs where oil samples are required for condition assessment, it is recommended to prepare a risk assessment for taking oil samples with the asset in service or recommend de-energisation.

1.7.9 INFORMATION

The AMS provides a hierarchical approach to understanding the information requirement to achieve JEN's business objectives at the Asset Class. From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives (Table 4-16). Table 4-17 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class.

Table 4-18 provides the information initiatives required to provide future information requirements.

Table 4-16: Transformer Business Objectives and Information Requirements

Business Objective	JEN Information Sources	Externally Sourced Data
Maintain safety, availability and reliability of transformers	SAP ERP (enterprise resource planning) DrawBridge (drawing management) Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee[5]. Alerts – from DB's and Government Organisations and manufacturers Manufacturing manuals AS/IEC standards

Table 4-17: Transformer Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Transformer - Asset Creation	• Specifications and tender responses • Zone Substation Primary Design Standard • New asset project progress reporting. Completion recorded in SAP • Asset register in SAP		• High – Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of the Transformer via	Asset register SAP, with details of each asset and significant components; • Manufacturer • Type	• Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	• High – Regulated to maintain supply reliability, safety and quality of supply

[5] The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)

inspections and audits	• Equipment description
	• Construction year
	• Basic specification
	  - Voltage
	  - Current
	• Location: Zone substation name
	• Address
	• Condition Monitoring
	  - Maintenance reports
	  - Test reports
	• Performance history
	  - Daily situation reports
	  - Investigation reports (ECMS)
	  - Plant defect reports
	• DrawBridge
	  - Single line diagrams
	  - plant data
	  - OEM manuals
	  - design drawings/layouts
	• SMI's – (Standard maintenance instruction)
	• SAP notifications and work orders activities performed, and components replaced.
	• Details of work completed recorded in SAP
		• Photograph transformer nameplate and attach to SAP equipment.
		• Determine transformer loading guideline.
		• Access all information via electronic tablet in the field.
		• Update asset data in SAP for missing or incorrect data.	

Maintain functionality of the Transformer via Preventive Maintenance	• Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. • Scheduled task description, timing and completion recorded in SAP; SMIs held in SharePoint, Policies & Forms. • Manufacturers maintenance manuals • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP • OPEX & CAPEX cost reporting recorded in SAP	• Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Maintain functionality of the Transformer via Condition Monitoring	• Condition monitoring tasks, schedule in SAP and results stored in proprietary test equipment database in SAP • Scheduled task description, timing and completion recorded in SAP. • Outputs from condition monitoring analysis.	• Migrate Condition & Performance reports/data into SAP to improve analysis and decision-making.	• High: Regulated to maintain supply reliability, safety and quality of supply

Respond to Transformer defects / faults to restore equipment operationally. Perform corrective maintenance.	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• basic specification
	  - Voltage
	  - Current
	• Location: Zone substation name
	• Address
	• SAP notifications and work orders activities performed and components replaced.
	• Details of work completed recorded in SAP
	• Condition Monitoring
	  - Maintenance reports
	  - Test reports
	• Performance history:
	  - Daily situation reports
	  - Investigation reports (ECMS)
	  - Plant defect reports
	• DrawBridge
	  - Single line diagrams
	  - plant data
	  - OEM manuals
	  - design drawings/layouts
	• Asset failure details and investigation reports. Stored in ECMS
	• OPEX & CAPEX cost reporting recorded in SAP
		• Although hard copies of manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in Drawbridge. Manufactures manuals for older assets may not be available.
		• Access all information via electronic tablet in the field.
		• All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.
			• High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Transformer – CBRM	• CBRM analysis Health Index • Held by Primary Plant	• The CBRM model was initially prepared in 2014. Since then, the product's original designers have no longer supported it.	• High: Regulated to maintain supply reliability, safety and quality of supply
Transformer – Rating suitable for load demand	• ZSS load forecast in ECMS • Published Distribution Annual Planning Report available on JEN website	• Determine transformer loading guideline	• High: Regulated to maintain supply reliability, safety and quality of supply
ACS Review	• Condition data • Fault/failure data • Maintenance & replacement costs • AMS		• Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-18: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph transformer nameplate and attach to SAP equipment Determine transformer loading guideline Access all information via electronic tablet in the field Update asset data in SAP for missing or incorrect data	To improve analysis and decision-making Asset data available from business systems saving on site trips To utilise full emergency rating of a transformer during system abnormal operating conditions	Poor efficiency in accessing asset data and delayed response when transformer full ratings are required	Transformer emergency rating and recommendation guideline will ensure accurate assessment and improved understanding in Asset Management Asset Data as per RCM and SAP requirements

1.8 ZONE SUBSTATION CIRCUIT BREAKERS

1.8.1 INTRODUCTION

This section includes information about the type and specifications of the circuit breakers and metal clad buses in service across the JEN.

A new 66kV Gas Insulated Switchgear (GIS) is currently being procured in accordance with a recently prepared JEN specification. This GIS system is required to supply a new HV customer with limited space, which precluded the installation of traditional air insulated outdoor switchgear. Once this new equipment has been installed and commissioned, all AMS requirements will be prepared, and further expanded in this document. In future, alternatives to SF6 will also be considered. For further information and design features, refer to the JEN GIS specification.

Circuit Breakers (CBs) are devices that operate automatically to interrupt current flows under network fault conditions. The main function served by circuit breakers is network fault isolation. They enable the distribution network to be safely constructed, maintained and repaired with minimal customer interruptions. They also allow JEN to respond to faults on the distribution network with minimal customer interruptions.

As of 2024, there are a total of 545 circuit breakers in operation across JEN; this number is made up of 73 66kV CBs, 328 22kV CBs, 91 11kV CBs and 53 6.6kV CBs. The 66kV and 22kV CBs are installed in a mix of indoor and outdoor environments, with all the 11kV and 6.6kV CBs being indoor.

A number of different insulating/interrupting mediums have been used in CBs which are indicative of the era in which they were manufactured. Bulk oil was typically used from 1940s to 1960s. Minimum oil was used from 1960s to 1980s with vacuum interrupters used in distribution voltage CBs from late 1970s to present day. SF6 gas has been used at all voltages from 1980s to present.

Outdoor CBs are either dead tank (DT), where metal enclosure(tank) is at earth potential with HV connections via bushings (bulk oil & DT SF6 plus a few vacuum CBs in metal enclosures), or live tank, where pole housings are single phase insulated (porcelain) with HV connections at top of poles; live voltage and mechanisms at earth potential.

Indoor CBs are arranged as a metal enclosed switchboard, containing an air insulated bus, CTs, VTs and cable terminations and normally rackable CBs, which are either bulk oil (BO), minimum oil, vacuum or SF6 types. Older switchboards (typically with BO CBs) are not compliant to an arc fault containment design, whilst newer (late 1970s onwards) switchboards including some older Vacuum and SF6 circuit breakers may comply to superseded standards. Older switchgear which do not meet arc fault containment standards are recommended for targeted replacement.

A typical zone substation has one or more 66kV CBs and between eight to twelve distribution feeders at 22kV, 11kV or 6.6kV distribution voltages supplying up to 30,000 residential customers.

1.8.1.1 *Asset Specification*

Table 4-19 lists the manufacturer, type, voltage, quantify and the installation location (zone substation) for this asset class.

Table 4-19: Circuit Breaker Information

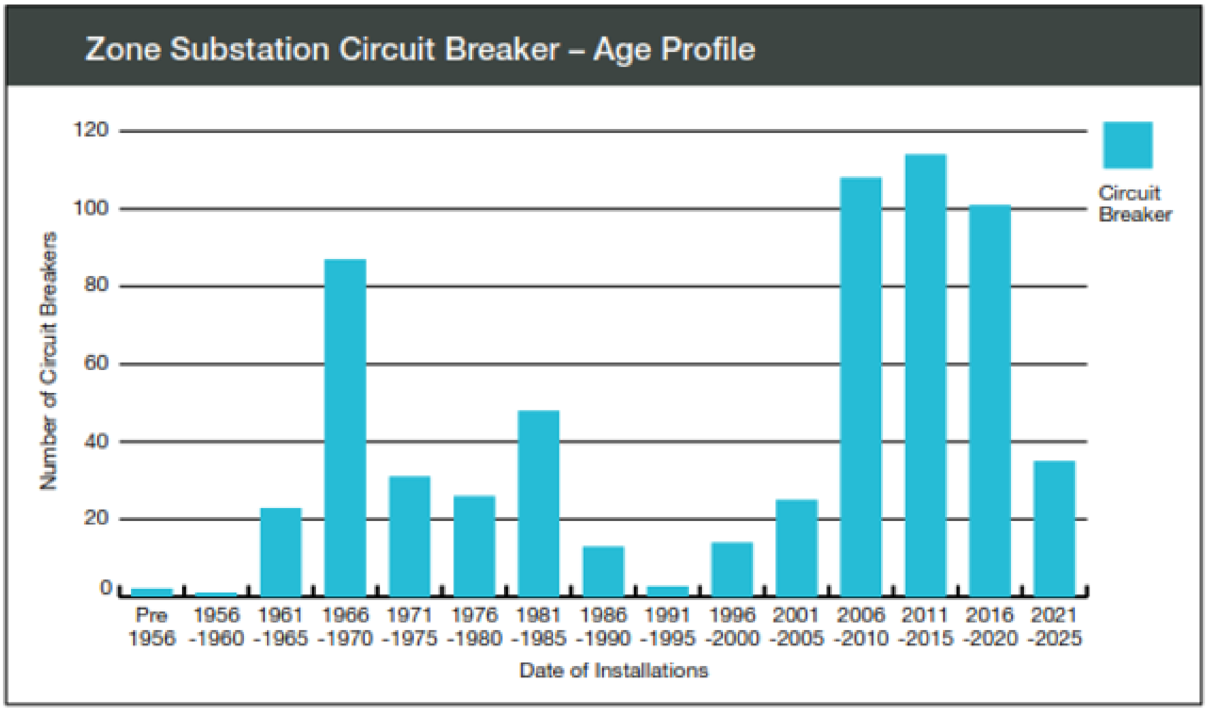
CB Manufacturer & Type	Voltage	Quantity	Zone Substation
ABB 72PM40 12B	66kV	2	BMS, TMA
ABB/Hitachi 72PM40-12C	66kV	10	ES, FE, HB, NEL, PTN, YVE
ABB EDF SK 1-1	66kV	7	BD, CN, SSS
ABB RMAG	22kV	1	BD
ABB PASS MOO	66kV	4	BMS, TMA
ABB VBF 36	22kV	1	BD
ABB VD4	11kV	88	ES, FE, FT, HB, NEL, NS, PV
	22kV	73	BD, BMS, SHM, ST, TMA

CB Manufacturer & Type	Voltage	Quantity	Zone Substation
AEI LG4C	66kV	7	CN, CS, EP, , FW, , NH, NT
ALSTOM S1-72.5F1	66kV	2	BY
ALSTOM DT1-72.5 F1	66kV	19	AW, COO, EPN, ES, PV, YVE, MAT, SBY
AREVA DT1-72.5 F1	66kV	1	SHM
ASEA HKEYC	66kV	1	EP
ASEA HLC 2000	66kV	2	CN, VCO
ABB HBS24	22kV	13	ST
CG 30-SFGP 25A	22kV	9	AW, CN, YVE
EMAIL WR 345GC	22kV	50	AW, BD, BLT, CN, FW
EMAIL J18	6.6kV	23	EP
ENGLISH ELECTRIC OLX	6.6kV	13	EP
GE DT1-72.5FK	66kV	2	BD
Metropolitan Vickers SB14	22kV	16	FW
SCHNEIDER AD4/SF-1	22kV	13	BY
SCHNEIDER SB6-72	66kV	3	MAT
SIEMENS 3AF	22kV	19	CN, TH
SIEMENS 3AH	22kV	4	NH, NS
SIEMENS 3AH1164	11kV	5	NS
SIEMENS 3AH5204	6.6kV 11kV	21 12	FF NS
SIEMENS 3AH5273	22kV	49	EPN, NT, YVE, SBY
SIEMENS 3AH5283	22kV	33	COO, EPN, NH, NT, SHM, YVE
SIEMENS 3AP1-DT	66kV	6	COO, NH, SBY, SHM
SIEMENS 3AP1FG	66kV	1	FE
SIEMENS 8BK20	22kV	7	SHM
S & S HPFC 409K	66kV	3	SBY, ST, TH
S & S HPTW306-FS	22kV	28	CS, FW, NH

1.8.1.1.1 Age Profile

Figure 4–8 shows the circuit breaker age profile and the percentage of population in nominated age groups.

Figure 4–8: Circuit Breaker Age Profile



Of the various circuit breaker age groups:

- 99 are over 50 years old, representing 18% of the total population (which will be prioritised for replacement using a condition and risk-based approach);
- 38 are between 40 and 50 years old, representing 7% of the total population (the ageing condition of which will be closely monitored as they approach and exceed 50 years).

1.8.2 RISK

This section includes information about circuit breaker risk profiles, how criticality is established, the risks posed by circuit breaker failure (including the various failure types and their possible consequences), other measures being introduced to manage asset risk, and a list of the various issues currently facing affected zone substations.

This information specifically involves:

- Asset class criticality score (sub-asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- CBRM for identifying assets approaching end of life;
- Existing controls;
- Asset Spares;
- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

The quantification of risk and the risk trends is important for providing top-down justification for the circuit breaker program of works.

A summary of these risks relevant to circuit breakers is provided in this section.

Risks for this asset class and the probability this will occur include:

- Regulatory non-conformance, likelihood is rare;
- Health and safety issues (equipment failure), likelihood is unlikely;
- Environmental issues (equipment failure), likelihood is unlikely;
- Financial Impact (loss of supply), likelihood is unlikely;
- Operational (loss of supply), likelihood is rare; and
- Reputational risk, likelihood is rare.

The potential consequences resulting from these faults can include:

- Serious – possibility of general regulatory queries;
- Severe – Single permanent partial disability;
- Serious – On-site release of pollutants with minimal impact;
- Serious – Loss of supply, Replacement of equipment (switchboard, bus, 66kV CB) is expected to be >100k and <$1M (excludes Service Target Performance Incentive Scheme (STPIS), direct costs only) due to plant replacement and collateral damage;
- Severe – Loss of supply to 3,000 customers for greater than 24 hours while switching transfers take place; possible rotational load shedding.

Emerging risks for this asset class include:

- Ageing population;
- Deteriorating insulation condition of buses and CB bushings of indoor switchboards;
- Damage due to vandalism, and
- Non-availability of components for old CBs and switchgear from suppliers/manufacturers.

1.8.2.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). The results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets that have the potential to impact the achievement of JEN’s operational objectives significantly. This is used to rank the importance of dissimilar sub-asset classes (e.g. transformers and buildings and grounds) to identify areas where risk should be managed first and control measures implemented.

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures.

For severe circuit breaker failures that cannot be repaired within 24 hours, the location within the network determines the impact on supply to customers. The following table demonstrates the various scenarios.

Table 4-20: Scenarios Depicting Strategic Failures

ZSS configuration	Failure item	Protection trips to isolate fault	Status post trips	Customer impact	Failure category
3 transformer, no 66 kV line CBs	66 kV Bus-tie CB	Remote end line CB & Other 66 kV B-T CB	2 transformers OOS; 1 transformers in service, may be overloaded	Likely to be some load shedding	Serious
2 transformer, no 66 kV line CBs	66 kV Bus-tie CB	Both remote end 66 kV line CBs	Both transformers OOS initially, then restored after fault isolated	All customers off supply initially, then restored after fault isolated	Serious
3 transformer, with 66 kV line CBs	66 kV line CB	Remote end line CB & 66 kV B-T CB; 22/11 transformer CB	1 transformer OOS	All Customer still on supply	Serious
3 transformer, with 66 kV line CBs	66 kV Bus-tie CB	66 kV line CB & other B-T CB; 2 22/11 kV transformer CBs	2 transformer OOS; 1 transformer in service, may be overloaded	Likely to be some load shedding	Serious
2 transformer, with 66 kV line CBs	66 kV line CB	Remote end line CB & 66 kV B-T CB; 22/11 transformer CB	1 transformer OOS	All Customer still on supply	Serious
2 transformer, with 66 kV line CBs	66 kV Bus-tie CB	Both 66 kV line CBs	2 transformer OOS initially, then restored after fault isolated;	All Customers off supply initially, then restored after fault isolated	Serious
3 transformer	22/11 kV transformer CB	22/11 kV B-T & 66 kV B-T	1 transformer OOS & 1 Bus OOS	Customers from 1 bus off supply	*Serious or Strategic
3 transformer	22/11 bus-tie CB	2 transformer CBs & other 22/11 kV B-T CB	2 buses OOS	Customers from 2 buses off supply	*Serious or Strategic
3 transformer	22/11 kV Feeder CB	22/11 kV B-T & transformer CBs	1 bus OOS	Customers from 1 bus off supply	*Serious or Strategic
2 transformer	22/11 kV transformer CB	22/11 kV B-T, 66 kV B-T & remote end 66 kV line CB	1 transformer OOS & 1 bus OOS	Customers from 1 bus off supply	*Serious or Strategic
2 transformer	22/11 B-T CB	2 transformer CBs	2 buses OOS	All Customers off supply	*Serious or Strategic

* For outdoor substation it is likely the faulted CB could be isolated and supply restored to the bus within 2 hours. For indoor it would depend if bus was damaged or just the CB which could be racked out & removed. If bus is damaged it would certainly take greater than 24 hours to restore supply.

In summary major failures of any distribution voltage (22/11/6.6 kV) circuit breakers will impact customers. Failures of sub transmission circuit breaker have a greater customer impact in 2 transformer zone substations compared to 3 transformer substations.

The circuit breaker has an asset criticality score of AC4 (High) due to operational and health and safety consequences associated with failures, as presented below:

- high replacement cost;
- high strategic impact on customer supply;
- long lead time for repair or replacement (typically 8-16 weeks for indoor), and
- high consequence of failure.

Circuit breakers contribute to JEN overall network reliability and STPIS via the minimisation of customer numbers off supply during the event of an outage or planned or unplanned maintenance. Therefore, a CB failure to operate can adversely affect the ability to operate the network and have serious consequences for public and personnel safety.

The circuit breaker asset group contains two major categories of CBs: Sub-transmission CBs and HV distribution CBs. Some zone substations have both sub-transmission line CBs and Bus-tie CBs, while others just have Bus-tie CBs. Should a line fault occur and the sub-transmission CB fail to operate, consequences can range from loss of redundancy with no outage to a whole zone substation off supply.

Table 4-21: Sub-transmission Line Outage Impact – with Line CBs

Substation with sub-transmission line CBs		Proportion of customers off supply	
Failure asset	**Impact**	**2 transformer substation**	**3 transformer substation**
Line CB	Outage of one transformer	Nil	Nil
Bus-tie CB	Outage of two transformers	100%	Overloading of the remaining transformer will lead to load shedding

Table 4-22: Sub-transmission Line Outage Impact – without Line CBs

Substation with sub-transmission line CBs		Proportion of customers off supply	
Failure asset	**Impact**	**2 transformer substation**	**3 transformer substation**
Bus-tie CB	Outage of two transformers	100%	Overloading of the remaining transformer will lead to load shedding

The impact of a HV distribution CB failure will depend on its position within the network configuration. The following CB functions and consequences are listed to demonstrate the impacts of a CB failure to operate assuming it was expected to interrupt a fault.

Table 4-23: HV Distribution CB Outage Impact

		Proportion of customers off supply	
Failure asset	**Impact**	**2 transformer substation**	**3 transformer substation**
Transformer CB	Outage of transformer and whole bus	50%	33%
Bus-Tie CB	Outage of two buses	100%	67%
Feeder CB	Outage of one bus	50%	33%

Therefore the criticality of an individual circuit breaker will be dependent on it position in the electrical network. In all cases however, greater outages will result from the non-operation of a HV distribution CB. These resultant impacts will also depend on the number of customers and load being supplied.

Criticality is further assessed for individual circuit breakers utilising CBRM. CBRM, which was introduced for JEN circuit breakers in 2014, is utilised to predict condition into the future (Health Indices) and estimate Probability of Failure. These tools are utilised to indicate required changes to asset management plans, to develop asset investment plans using existing asset data and other information and determine when end-of-life replacement will be required. Assets with a higher health index score are targeted for further analysis before imminent replacement. For further information on CBRM, its inputs and outputs and methodology, please refer to Appendix K.

1.8.2.2 *Spares*

As part of the criticality assessment, consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002). It was determined that adequate circuit breaker component spares are maintained at Tullamarine depot and stock holdings are managed by the JEN and external contractors teams. Spare 66kV, 22kV, 11kV and 6.6kV circuit breakers are also available.

JEN has various types of spare breakers and components for 22kV/11kV/6.6kV CBs and some bus components and one spare for 66kV CB. Capital projects have been/will be initiated to replace CBs in poor condition and this will address some of the spares issue

System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub transmission line due to a CB failure.

Critical Spares Assessment Procedure (ELE-999-PR-RM-002) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I.

Furthermore, when assets are retired from service consideration is given to retaining components or entire asset as spares to service existing aging fleet.

It is recommended to purchase six modern equivalent spare bushings for Email type 345GC Circuit Breakers in the next period.

The condition of any spare HV plant must be determined via condition testing prior to placing into service. Any spare removed from service in poor condition must be scrapped.

1.8.2.3 *Failure Modes*

Circuit breakers are installed to fulfil critical functions associated with the safe and reliable operation of the HV network. Circuit breakers can experience tripping defects and in rare circumstances catastrophic failure can occur.

The dominant circuit breaker failure modes that impact on the reliability of the network are as follows:

- failure to insulate due to lightning; over-voltages due to switching, animals and birds or water penetration;
- failure to interrupt or make fault currents;
- failure to carry load due to high resistance connections resulting in thermal overheating; and
- failure to trip due to mechanism problems that prevent the CB from opening or may result in slow operation. This will cause back up protection to operate which may result in the loss of supply from a bus or whole zone substation, and the CB may be damaged.

1.8.2.4 *CBRM Health and Risk Analysis for Circuit Breakers and Metal clad Buses*

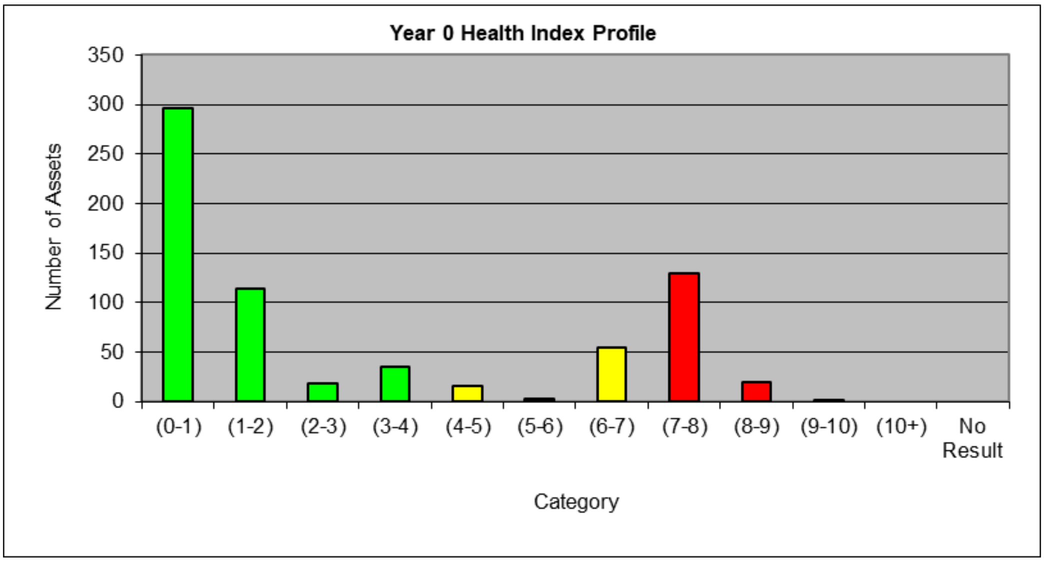
CBRM results indicate that the current (Year 0) health index is as shown in Table 4-24. A total of 92 circuit breakers have been identified to be in poor condition (HI > 7) with a higher probability of failure. These circuit breakers are listed as follows.

Table 4-24: CBRM Output (poor condition (HI > 7)) for Circuit Breakers – Year 0 as at 2024

ZSS	Voltage (kV)	Qty.	Manuf.	Model	HI range	Comment
AW	22	15	Email/WR	345GC	7.98 – 8.25	Switchyard future planned replacement 2033
BD	22	18	Email/WR	345GC	7.98 – 8.25	Switchyard future planned replacement 2033
BLT (BLTS)	22	2	Email/WR	345GC	8.25	22kV MB FDR CBs future planned replacement 2026
CN	22	12	Email / WR	345GC	7.98 – 8.25	Switchyard future planned replacement 2028
CS	22	9	S & S	HPTW30 6-FS	7.15	Switchgear future planned replacement 2029
EP	6.6	9	Email	J18	7.15 – 7.43	To be retired – Voltage conversion project 2025
FW	22	1	Email/WR	345GC	7.98	Planned replacement 2025
FW	22	12	MV	SB14	7.01 – 8.41	Planned replacement 2025
NH	22	13	S & S	HPTW30 6-FS	7.15 – 7.70	Switchyard future planned replacement 2031
YVE	22	1	Crompton Greaves	30-SFGP 25A	7.02	Switchgear future planned replacement due to gas leak 2025

Figure 4–9 shows there are a total of 150 circuit breakers (as at 2024, Y0) in the red zone with Health Indices of 7 or above if no replacement projects take place, indicating an elevated probability of failure.

Figure 4–9: Year 0 Health Indices as at 2024 (Circuit Breakers including Buses)



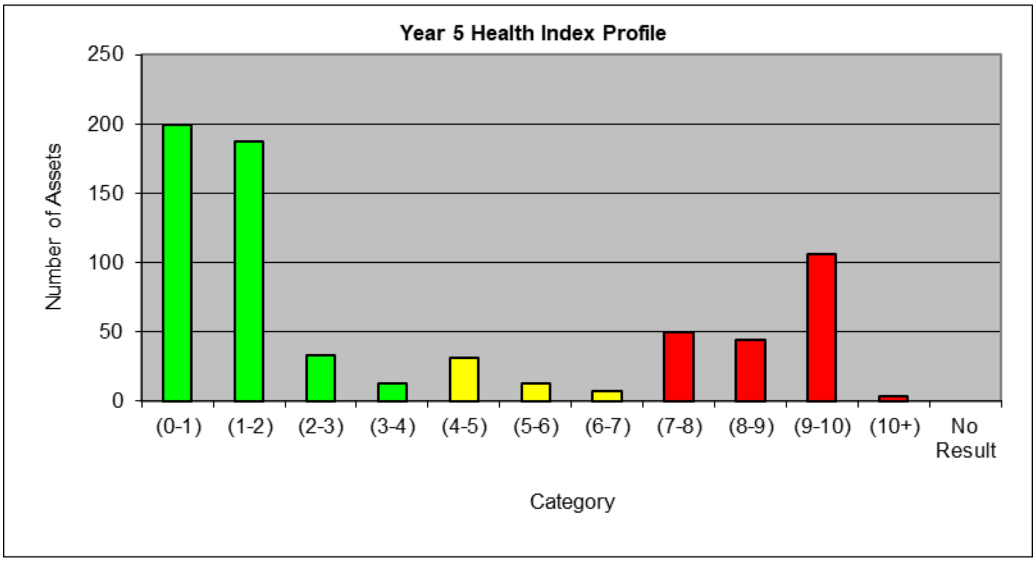
If asset replacement is deferred until 2028 (Year 5) the health index changes as shown in Figure 4–10. A total of 203 circuit breakers will be in poor condition (HI > 7) with the associated higher probability of failure. These assets are located at the following locations.

Table 4-25: CBRM Output for Circuit Breakers – Year 5 as at 2024

ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ Year 5
AW	22	16	Email/WR	345GC	8.21 − 9.84
AW	22	1	Crompton Greaves	30-SFGP 25A	8.01
BD	22	18	Email/WR	345GC	7.98 – 8.25
BLTS (MB FDRs)	22	2	Email/WR	345GC	9.59 – 9.62
CN	22	12	Email/WR	345GC	9.4 − 9.75
CN	22	1	Crompton Greaves	30-SFGP 25A	7.62
CN	66	1	AEI	LG4C	7.7
CS	22	9	SPRECHER & SCHUH	HPTW306-FS	7.15
EP	66	1	ASEA	HKEYC	7.0
EP	66	1	AEI	LG4C	7.7
EP	6.6	23	Email	J18 -LC	029.07
EP	6.6	10	English Electric	OLX	7.02 – 7.08
FW	22	1	Email/WR	345GC	10.1
FW	22	12	MV	SB14	7.8 – 8.67
FW	22	2	SPRECHER & SCHUH	HPTW306-FS	7.66 – 8.09
FW	66	2	AEI	LG4C	7.79
NH	22	13	SPRECHER & SCHUH	HPTW306-FS	7.54 − 9.24
NH	66	1	AEI	LG4C	7.84

ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ Year 5
NT	66	1	AEI	LG4C	7.81
YVE	22	1	Crompton Greaves	30-SFGP-25A	10.3

Figure 4–10: Year 5 Health Indices as at 2024 (Circuit Breakers including Buses)



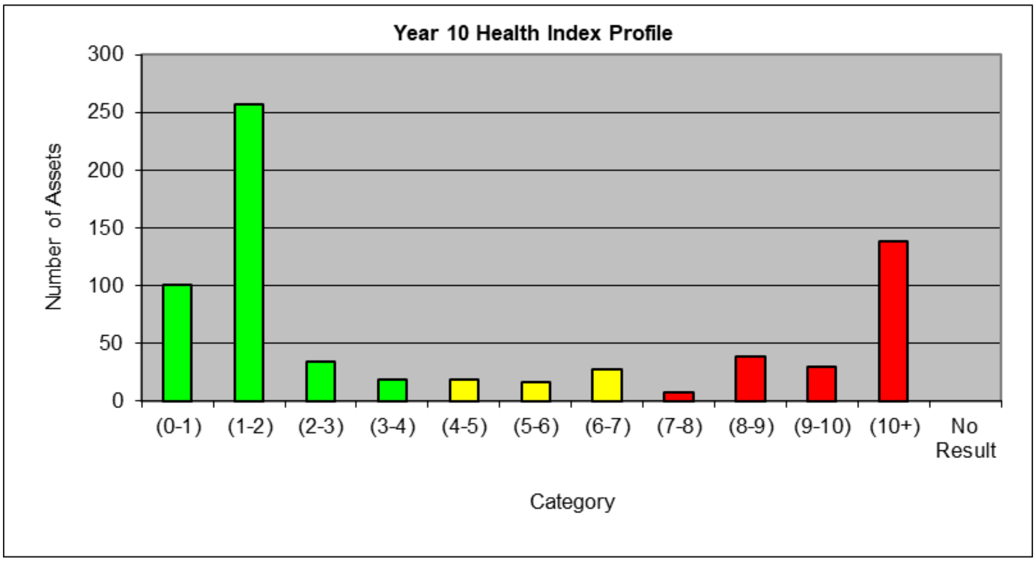
If circuit breaker replacement is deferred until 2033 (Year 10) the health index changes as shown in Figure 4–11. A total of 214 circuit breakers will be in poor condition (HI > 7) with the associated higher probability of failure. These assets are located at the following locations.

Table 4-26: CBRM Output for Circuit Breakers – Year 10 as at 2024

ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ year 10
AW	22	16	Email/WR	345GC	10.08 – 12.13
AW	22	3	Crompton Greaves	30-SFGP 25A	9.49 – 11.10
BD	22	18	Email/WR	345GC	10.79 – 11.39
BLTS (MB FDRs)	22	2	Email/WR	345GC	11.15 – 11.21
CN	22	12	Email/WR	345GC	11.09 – 11.52
CN	22	1	Crompton Greaves	30-SFGP 25A	10.5
CN	66	1	AEI	LG4C	8.97
CS	22	13	SPRECHER & SCHUH	HPTW306-FS	8.85 – 10.51
CS	66	1	AEI	LG4C	9.62
EP	66	1	ASEA	HKEYC	8.1
EP	66	1	AEI	LG4C	8.97
EP	6.6	23	Email	J18 -LC	8.14 – 11.07
EP	6.6	13	EE	OLX	7.88 – 8.28
FW	22	1	Email/WR	345GC	12.66
FW	22	16	MV	SB14	8.68 – 9.75

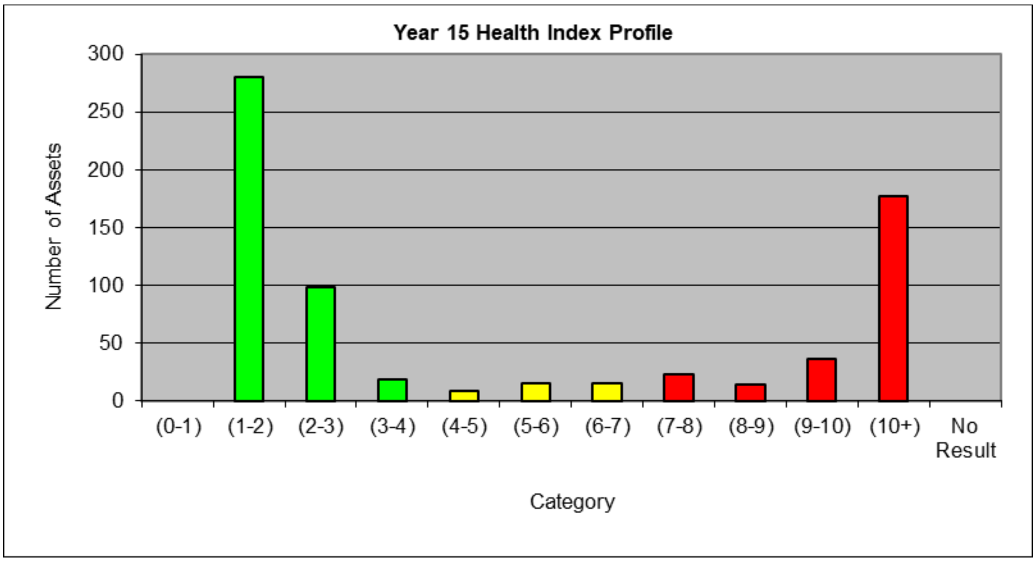
ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ year 10
FW	22	2	SPRECHER & SCHUH	HPTW306-FS	9.92 – 9.40
FW	66	2	AEI	LG4C	9.19
NH	22	13	SPRECHER & SCHUH	HPTW306-FS	10.19 – 11.09
NH	66	1	AEI	LG4C	9.31
NT	66	1	AEI	LG4C	9.25
YVE	22	1	Crompton Greaves	30-SFGP 25A	15

Figure 4–11: Year 10 Health Indices as at 2024 (Circuit Breakers including Buses)



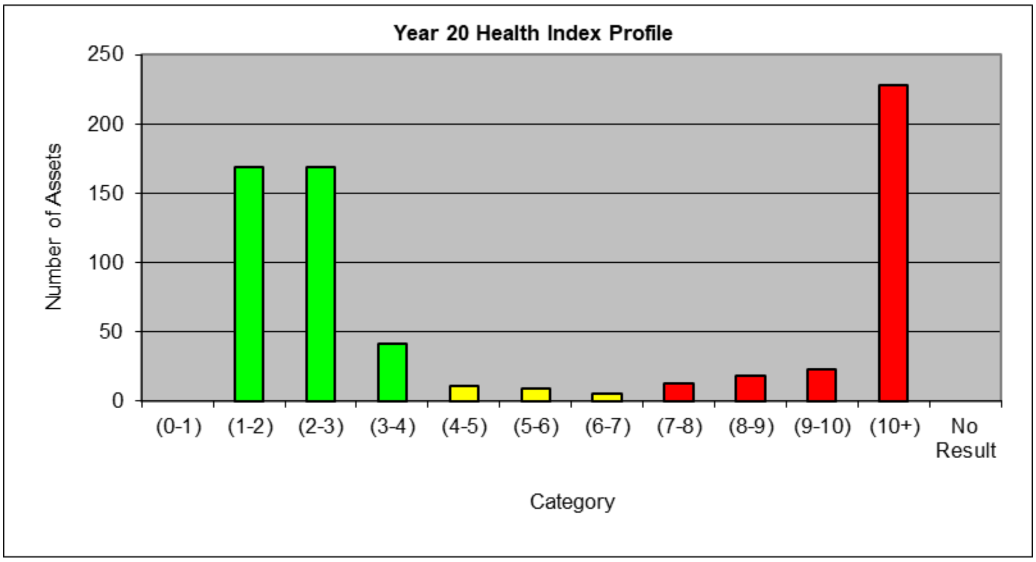
If circuit breaker replacement is deferred until 2038 (Year 15) the health index changes as shown in Figure 4–12.

Figure 4–12: Year 15 Health Indices as at 2024 (Circuit Breakers including Buses)



If circuit breaker replacement is deferred until 2043 (Year 20) the health index changes as shown in Figure 4–13.

Figure 4–13: Year 20 Health Indices as at 2024 (Circuit Breakers including Buses)



These results indicate that replacement of these circuit breakers in the coming years should be undertaken in order to manage the risks associated with the number of circuit breakers in poor condition on the network.

Further scenario analysis will be undertaken to determine optimal replacement schedules however the 22kV circuit breakers identified at FW as in poor condition at Year 0 will take priority. The Metropolitan Vickers type SB14 switchgear at FE have been replaced during 2021 and 2022.

1.8.2.5 *CBRM Health and Risk Analysis for Metal clad Buses*

Metal clad circuit breakers are an integral part of the metal clad bus. The condition and performance of the CBs and buses is monitored and when a bus is deemed necessary to replace, all CBs will also be replaced. Defects and faults associated with circuit breakers are addressed for restoration to normal system provided spare parts are available. When a CB ages, the major insulation, such as bushings installed on oil CBs, cannot be safely restored to its original new condition, and this affects the greater population of J18 and OLX CBs. Retrofitting new VCBs or Gas CBs shall not be implemented.

Initial CBRM results indicate that the current (Year 0) health index for metal clad buses is as shown in Table 4-27 below. A total of 13 metal clad buses have been identified to be in poor condition (HI > 7) with a higher probability of failure.

Table 4-27: CBRM Output (poor condition (HI > 7)) for Metal clad buses – Year 0 as at 2024

ZSS	Voltage (kV)	Qty.	Manuf.	CB Type Fitted	HI range	Comment
CS	22	2	S & S	HPTW306-FS	6.81*	Planned replacement 2029
EPA	6.6	3	English Electric & Email	OLX/J18	8.25 – 9.08	To be retired – Voltage conversion 2025
EPB	6.6	3	English Electric	J18	6.33 – 8.06	To be retired – Voltage conversion 2029
FW	22	3	MV	SB14	8.41	Planned replacement 2025
NH	22	2	S & S	HPTW306-FS	7.6	Planned replacement 2031

*Although the HI for the CS 22kV metal clad buses is <7, visible partial discharge has been observed during maintenance and follow up with electrical testing. Remediation work will be undertaken at CS and NH to maintain reliability and safety until the assets are replaced in the 2026-31 regulatory period. Refer to section 1.8.3.2.

If asset replacement is deferred until 2029 (Year 5) the health index changes as shown in Table 4-28. A total of 13 metal clad buses will be in poor condition (HI > 7) with the associated higher probability of failure.

Table 4-28: CBRM Output (poor condition(HI > 7) for Metal clad buses – Year 5 as at 2024

ZSS	Voltage (kV)	Qty.	Manuf.	CB Type Fitted	HI range	Comment
CS	22	2	S & S	HPTW306-FS	8.23	Planned replacement in 2029
EPA	6.6	3	English Electric & Email	OLX/J18	9.45 – 10.66	To be retired – Voltage conversion in 2025
EPB	6.6	3	English Electric	J18	7.72 – 9.19	To be retired – Voltage conversion in 2029
FW	22	3	MV	SB14	9.38	Planned replacement in 2025
NH	22	2	S & S	HPTW306-FS	9.15	Planned replacement in 2031

1.8.2.6 *Existing Controls*

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.2.6.4., together with initiation of replacement projects for assets determined to be in danger of major failure.

JEN has various types of spare breakers and components for 22kV/11kV/6.6kV CBs & buses and one spare for 66kV CBs. Capital projects have been/will be initiated to replace CBs in poor condition and this will address the spares issue. JEN however does not have full complement of spares for every circuit breaker or bus on the network.

Note that the spare 66kV DTCB is not serviceable and is awaiting repair.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and reparability of the failed circuit breakers. Once determined, either components are replaced or whole unit replaced with a spare from stock.

1.8.2.7 *Further Information on CBRM*

For further information on CBRM please refer to ELE GU 0005 Condition Based Risk Management (CBRM) Application Guide. The guide provides a summary of how JEN utilises CBRM to justify future replacement volumes for distribution and zone substation assets. It outlines the different inputs required and their associated outputs and how these outputs are interpreted. The CBRM model was initially prepared in 2014.

1.8.3 PERFORMANCE FACTORS

Circuit breakers are expected to provide their rated switching and fault interruption functions, when required, for a lifetime in the order of 50 years. Therefore, all factors contributing to maintaining satisfactory condition are essential to achieve this goal.

Asset performance for circuit breakers is assessed through a holistic asset management approach that includes routine maintenance, testing, diagnostic condition assessments and CBRM. This work is carried out in line with the various associated plans, policies, strategies and standards.

Asset performance measures for JEN zone substation circuit breakers are designed to achieve a high level of reliability by undertaking a practical, efficient cost program of preventive and corrective maintenance, coupled with planned, economic replacement of circuit breakers before failure; to maintain reliability and quality of supply and mitigate the safety risk to personnel and the public.

Specific circuit breaker performance measures (and condition monitoring) include the following:

- Condition monitoring tests: insulation resistance, partial discharge, dielectric dissipation factor and capacitance.
- On-line, non-disruptive monitoring surveys: measurement of transient earth voltages for metal enclosed switchgear and ultrasonic and UHF detection for air borne partial discharge signals.
- CBRM output in the form of Health Indices for present and prediction into the future without proactive intervention.

1.8.3.1 *Performance requirements and targets*

Specific Asset Management Performance requirements for this asset group include:

- Known condition – completion of nominated condition monitoring tasks at the frequency specified in Section 1.8.6.6 Condition-based monitoring and assessment of the results evidenced by reports available for each asset;
- Preventive maintenance – completion of nominated preventive maintenance tasks specified in Section 1.8.6.4.2 Circuit Breaker Preventive Maintenance & records of tasks completed;
- Planned replacement – identification of end-of-life replacements each year, incorporation in annual works programs and obtaining replacement project approvals; and
- Failure Prevention – avoiding catastrophic (unplanned outage more than 24 hours) circuit breaker failures from occurring within zone substations- target zero per year.

The circuit breaker has a general life expectancy of 50 years for both indoor and outdoor installations. Properly electrically protected, correctly loaded and adequately maintained, a circuit breaker's life expectancy can exceed 50 years. Of the total number of circuit breakers in service across JEN, 21% are in the 41 – 50 year age range. Sixteen per cent of the population is over 50 years old.

Factors affecting this life expectancy include:

- Condition of the insulation system of its interruption system;
- HV bushings;
- Build quality; and
- Installation location, i.e. indoor or outdoor (those installed outdoors are more susceptible to vermin and moisture ingress, accumulation of pollution and degradation due to sunlight).

1.8.3.2 *Condition Assessment*

A number of factors are assessed to determine if individual circuit breakers have a high probability that the unit will continue to perform its required function reliably. Aspects such as age, condition, utilisation, effectiveness of risk controls, and actual performance are analysed and examined. Outputs from the CBRM model are used to provide a comprehensive assessment of CB/switchgear condition.

CBRM outputs in the form of Health Indices shown in Section 4.2.2.3 above provide a visual demonstration the condition of the population of circuit breakers now and into the future if no corrective measures are taken.

Circuit breaker current issues have been identified and documented at a number of zone substations that include Airport West (AW), Broadmeadows (BD), Braybrook (BY), Broadmeadows South (BMS), Coburg North (CN), Coburg South (CS), East Preston (EP), Footscray West (FW), North Heidelberg (NH), Sunbury (SBY)Tullamarine (TMA), Tottenham (TH), and Yarraville (YVE). The following provides specific information about circuit breakers issues, as well as general information about other potential and related issues.

ABB/Hitachi 72PM40-12B and the PASS MOO CBs

These types of CBs are located at BMS and TMA and are used for 66kV bus Tie CBs and line CBs, respectively. Investigation reports into the failure of the close spring in each CB have been prepared. This is a significant failure of a substantial mechanism component which had occurred and was subsequently repaired. ZSS MAT was forced onto a single contingency supply until the repairs were completed. The two PASS MOO CBs and single 72PM40-12B CB at TMA will be replaced with modern equivalents due to the unreliable nature of the close spring, having failed twice. These CBs will be retained as spares to support BMS. Spare components are becoming increasingly difficult to source in a timely manner. In addition, the manufacturer offered a modification of the spring wind motor circuit to prevent over-winding of the closed spring. This needs to be assessed and implemented at BMS. Future replacement of the BMS 66kV CBs should be considered as resources from the manufacturer are required to replace the failed close spring. The external resources may be limited. The 72PM40-12B CB is a discontinued product.

ABB SACE HA1 22kV CBs

These CBs on the No.3 22kV bus at zone substation ST have been replaced with ABB VD4 vacuum breakers. The CBs reached their auto points limits and were found with poor quality SF6 in the interruption chambers and excessive mechanical wear of internal components, particularly on the capacitor bank CBs.

ABB VD4 11kV and 22kV CBs – Sub BMS, ES, HB, PV and TMA

In June 2015 HB32 11kV FDR CB failed to reclose after tripping on a phase-to-phase fault in the JEN distribution system. Three unsuccessful attempts were made by JEN network control to close the HB32 FDR CB remotely. An operator subsequently attended the site and racked the CB out and then racked it back in; the CB was then successfully closed. Investigations into this issue revealed that the inherent design of the VD4 CBs is such that there is a small tolerance, approximately 10deg, for where the racking mechanism will be in the service position. A plant bulletin, with a directive on how to mitigate against this issue, has been disseminated to the field crew to make them aware of this issue.

Alstom DT1-72.5FK CBs

The 4-1 66kV bus tie CB at AW failed to trip due to an issues with the trip spring retaining cone. This cone which connects the trip spring to the CB operating rod in the mechanism had fractured. The spare Alstom 66kV CB was installed as the defective mechanism needs to be repaired by the manufacturer.

Alstom S1-72.5 F1 66kV

Following the failure of the 2-3 66kV bus-tie CB at ZSS FE in 2012 and subsequent repair of the KTS-BY 66kV & 1-2 66kV bus-tie CB at BY zone substation (investigated in June 2014 and repaired in November 2014), timing checks of all 66/22/11/6.6kV SF6 and Vacuum CBs are recommended. A suitable timing test set has been purchased.

ASEA HKEYC 66kV CBs

JEN presently has 1 HKEYC 66kV circuit breakers in service EP zone substation. These CBs are no longer supported by the manufacturer, and consequently, spare components such as porcelain interrupter poles, support stacks and external drive insulators are no longer available. The 66kV ASEA HKEYC circuit breakers are rated at 800A and can impose limits on 66kV line ratings. The circuit breakers need to be upgraded to 1250A to match modern line ratings. Two of the HKEYC CBs located at Sub BD have been replaced in 2019 in consideration of the condition issues identified above. The CBs have reached a service life of 52 years. This project was aligned with the relay replacement and control building upgrade project at ZSS BD in 2017. One HKEYC CB located at Sub ES has been replaced (55 years old) in 2017. Zone substation EP is being retired in 2021 as part of the conversion of the 6.6kV feeders to 22kV. The spare parts made available from the retirement of the HKEYC CBs at BD and ES will provide sufficient spare parts for the CBs at EP until EP is retired.

ASEA HLE 66kV CBs

The 2 HLE 66kV circuit breakers remaining in service at SBY zone substation on JEN were replaced in 2018 as part of a major project at SBY. The circuit breakers were over 50 years old upon their replacement.

AEI LG4C 66kV CBs

JEN presently has 7 LG4C 66kV circuit breakers manufactured from 1966 onwards in service at zone substations CN, CS, EP, FW, NH and NT. These CBs are no longer supported by the manufacturer, and consequently, spare components such as 66kV bushings, turbulators, solenoids and mechanism components are no longer available. A defect has been identified in the mechanism of these CBs involving the retaining of a shaft by a washer that is peened on the end of the shaft. This has resulted to damage to the mechanism. An inspection of all of these breakers has been undertaken and a plant defect notice issued.

A bushing testing and refurbishing program has been completed due to a history of failures experienced within the Victorian industry. It is recommended that DDF testing is carried out periodically for the bushings and oil levels monitored at regular intervals. PD testing is also a recognised test that should be undertaken at the same time as DDF testing. Three LG4C CBs at ZSS AW were replaced in 2017. One LG4C CB at CN will be replaced with the 22kV CB and relay replacement project. One LG4C CB at HB has now been replaced as part of the transformer replacement. One LG4C CB at FE has now been replaced with the 22kV switchboard replacement project. Two LG4C CBs at FW will be replaced with the 22kV switchboard replacement project in the near future. EP is to be shut down in the near future, and one LG4C CB will be retired. The remaining ZSS consist of indoor and outdoor 66kV LG4C CBs, which are to remain in service and be supported by the spares obtained from those retired from service.

Brown Boveri HBS24 CBs

These CBs were installed at Sub ST in 1985 and were found to leak SF6 gas. Feeder ST24 CB was refurbished in 2005 after 20 years of service. Manufacturers of SF6 CBs generally specify that seal replacement is necessary after about 25 years of service due to the hardening of rubber seals. Although CB gas levels are locally monitored, seal replacement, major overhaul of interrupter due to fault current interruption and mechanism overhaul is inevitable. A program of work has been prepared and budgeted that prioritizes the refurbishment of the ST CBs. Work includes an assessment of contact wear, ‘O’ ring condition and filtering/dry-out of gas due to by-product formation. All CB on No1 & 2 buses, plus the spare CB, have been completed.

This switchgear above is recommended for targeted replacement, as it is aged (condition) and non-arc fault rated. During the refurbishment program, it was evident that new spare components are scarce. This switchgear may longer be supported by the manufacturer.

Crompton Greaves – 30-SFGP-25A 22kV CBs

There have been ongoing issues with these CBs installed at ZSS AW, CN, SBY (Replaced) & YVE. Gas leaks were found in one CB at SBY and one CB at YVE; both of these CBs had all three poles replaced with refurbished poles. In March 2014, while undertaking corrective maintenance on the AW No.4 22kV transformer CB, the shock absorber was found to have been dislodged. Further investigation found a gas leak from one of the poles of the CB. All three poles were replaced with refurbished poles and the CB was put back in service. This problem has reoccurred a second time, and this CB is recommended for replacement.

During 2019 at ZSS AW, the No.4 transformer 22kV CB red phase pole failed to close due to an internal defect and dashpot failure following a sub-transmission feeder fault. The CB poles were rebuilt using retired spares from ZSS SBY.

YVE No. 4 transformer 22 kV CB has had a long history of SF6 gas leaks and is being monitored. The refurbishment of the CB was unsuccessful, and the CB continues to leak gas at an increased frequency. This CB has been topped up with gas 4 times in 2019.

With a series of ongoing defects associated with this type of CB, a project will be prepared to replace the AW No.4 transformer 22kV CB and YVE No. 4 transformer 22 kV CB. The remaining fleet of Crompton and Greaves CBs shall be considered for replacement.

In June 2013, the SBY14 feeder CB failed when it was slow to open on a feeder fault. It was discovered that an incorrect-specified lubricant was being used on the mechanism of these CBs. Subsequently, a plant bulletin was sent out highlighting the problem and recommending the correct lubricant. These CBs were replaced with indoor switchgear at SBY as part of the SBY rebuild project in 2018.

Email 345GC 22kV CBs

The 22kV Email 345GC circuit breaker is an outdoor oil-filled CB located within various zone substations. These CBs have been undergoing a bushing refurbishment program due to a history of compound leaks from the bushings. This refurbishment program is designed to prevent bushing failure. To date, the old compound (Pitch) filled bushings have been refurbished several years ago; however, now there are signs of the new compound leaking from the bushing gaskets. These bushings can no longer be refurbished as this external service is no longer available. A number of spare bushings have been retained from retired assets. The spare bushings are tested prior to being stored for future use. JEN can also procure silicon rubber bushings, although these are much more expensive than the existing bushings used in these circuit breakers.

There have also been minor defects associated with the CB mechanism, particularly with capacitor bank CBs. This issue has been managed successfully. In addition, there are asbestos arc chutes for the CB closing supply.

There have been a number of failures of the main contact pull rod. The maintenance schedule has been modified to remove the class 2 overhaul at 12 years and implement a class 2 overhaul at 6 years to identify any fractured pull rods and deal with aged components. Generally, this failure mode is associated with capacitor bank switching and the associated onerous operating duty. However, this failure mode has now appeared on transformer CBs. It is also suspected that the leaking dashpots is a contributing factor causing the failure of the pull rods. A project to replace the existing Permali wood pull rods in all 345GC capacitor bank CBs with fibre glass pull rods has been completed. During the pull rod replacement project, it was further identified that the pull rod guides were worn and unserviceable. When a defective pull rod is identified in any other breaker, pull rods on all three phases will be replaced with fibreglass pull rods and the dashpot will be serviced. The significance of a pull rod failure is serious as one phase can fail to open when the CB trips to clear load or fault current, which will impact customer supply to a much greater extent. Furthermore, if the operator is unaware that one phase remains closed, then there is a risk of breaking the load current when the single phase 66kV isolator is opened.

There is evidence to indicate that new failure modes are emerging as the asset continues to age beyond the expected serviceable life. Engineering new components can mitigate the failure of some existing components, but this process is costly, and it does not mitigate the age-related failure of other components within the CB. The manufacturer of this type of CB no longer provides spare parts or engineering support, and JEN engineering expertise is limited.

In September 2015, BD3 22kV FDR CB failed to open when a command was issued from JEN's control room. Upon investigation, it was identified that the trip latch assembly presented with a build-up of sticky/tacky residue. The residue was a consequence of applying/spraying lubricant to the mechanism without cleaning the existing lubricant. Consequently, the trigger and rollers were not moving freely. Once cleaned, the trip latch assembly will move freely. The CB mechanism was cleaned thoroughly and lubricated with Shell Tellus Oil, and the circuit breaker was subsequently returned to service on the same day. In 2016, two Email 345GC CBs tripped slowly, resulting in customer outages and STPIS penalties. A one-off mechanism refurbishment program was completed for all email type 345GC CBs on the network to address the ongoing lubrication and maintenance issues in 2017. This program was supplementary to the current class 1 and 2 (incl. after auto and service ops) maintenance regime facilitated through SAP. Furthermore,, during the CB mechanism refurbishment program, one of the CBs at BD was assembled incorrectly and failed to trip. An Investigation report has been prepared.

Greater attention is required to cleaning and removal of old dried lubricants and the use of suitable lubricants to last the intervals between maintenance.345GC CBs at zone subs CN will be considered for replacement with indoor switchgear The remaining 345GC CBs at zone subs AW, BD and BLTS will be considered for replacement during the next price review period.

English Electric OLX and Email J18 6.6kV CBs

The existing 6.6kV switchboards at EP date from 1952. Zone substation EP consists of two switch rooms. Switch room A comprises a mix of Email J18 and English Electric OLX circuit breakers, while switch room B comprises entirely of Email J18 circuit breakers. There is an extensive history of plant defects for this type of switchgear, including instances of failure resulting in fire damage to the switchboard and damage to the control building at FT (Flemington) Zone Substation and at substations owned by other Victorian distribution businesses. The English Electric OLX circuit breakers, in particular, have had numerous mechanical failures of differing modalities.

Condition monitoring tests have been/are periodically conducted on the EP switchgear. The current DLA testing regime is set to be annually on the switchgear at EP, along with the annual condition monitoring testing. DLA testing conducted on the switchgear at EP in 2012, 2017 and annually in subsequent years has identified that the insulation properties of the 6.6kV switchboard have deteriorated since initial testing in 2012 and are well outside of acceptable limits. All circuit breakers installed at Zone Substation EP are regarded as severely degraded and have been in this state since at least 2012.

Bushing replacements were undertaken at the EP Zone Substation, with spares taken from the P Zone Substation and Pascoe Vale (PV) Zone Substation, to replace the 6.6 kV CB bushings that were showing a high level of insulation degradation. There are currently no spares available to replace faulty bushings or bushings with high DDF readings at EP Zone Substation. The bushing construction is resin bonded paper with the majority of the bushing length exposed to air. Once moisture ingresses, the bushings cannot be repaired. Bushings with high DDF readings may indicate future current leakage to earth due to moisture ingress in the insulating medium, which then leads to thermal runaway and can cause catastrophic insulation failure and oil fire. In the event of a circuit breaker bushing failure at EP there are no spares available to reinstate the circuit breaker or rebuild the bus work. All feeder CBs at EP are annually tested to monitor their degradation. These measures have been put in place to ensure a safe and reliable operation of the EP switchboard until it is retired as part of the voltage conversion program and EPN is expanded.

Email J18 and J22 11kV CBs

The existing J18 and J22 switchboard at Zone Sub FT was replaced with new ABB VD4 switchgear in 2018.

Metro Vickers SB14 CBs

Metropolitan Vickers type SB14 switchgear installed at FW is estimated to be over 86 years old and is unique to JEN. No other Australian Electricity Business has this switchgear installed. The condition of this switchgear has degraded to a point where employee safety, reliability and security of customer supply may be affected. Note the replacement of this type of CB and associated buses has been completed at FE.

In March 2013, the field crew advised that the CBs at FW were leaking oil from either the bus or the feeder isolator compartment. Subsequently, repairs were undertaken, and while the oil leaks have slowed, they haven't completely stopped. The CBs will be continually monitored until their replacement.

These CBs (and associated buses) installed at FW are showing signs of age-related deterioration. Condition monitoring tests conducted on the indoor 22kV buses indicate that Partial Discharge (PD) is present above service voltage. This indicates that insulation degradation has occurred. The same switchgear prior to replacement at FE also showed signs of insulation failure when tested. The Condition monitoring tests conducted on the indoor 22kV buses at FW indicate that Partial Discharge (PD) may be present during normal operating conditions. The damage due to PD cannot be stopped or reversed. Overvoltage excursions due to lightning strikes on the network or switching surges can accelerate insulation degradation further. This will increase the level of PD. The presence of PD will continue to degrade the insulation, which will ultimately cause the insulation to fail catastrophically.

Periodic condition monitoring on these switchboards has been scheduled. This includes 6 monthly online and five yearly offline condition testing.

This switchgear at FW is planned for replacement.

McGraw Edison and Merlin Gerin Step Switches

The capacitor bank step switches at CN and SBY failed and have not been replaced. The capacitor bank rating has effectively been reduced, and this appears not to have affected the performance of the zone substations. If replacement step switches are required for reactive support, a decision needs to be made to install them.

AEI JB424 and Reyrolle OMT 22kV CBs

SBY 33 CB (AEI type JB424) and the No.1 capacitor bank CB (Reyrolle type OMT) were the only examples of these CBs installed on the JEN network. These CBs were no longer supported by the manufacturer and were replaced as part of SBY zone sub rebuild project in 2019.

Sprecher & Schuh HPTw306 22kV CBs

These are minimum oil circuit breakers and are installed at Sub NH, CS, and FW. Recently, oil leaks have been found on these CBs, which could lead to CB failure. The construction of these CBs and their deployment means that oil levels in the CBs can only be monitored when the CB is racked out of the service position. Being minimum oil breakers, the total oil volumes held in each CB pole are small. The loss of one litre of oil can result in catastrophic failure. It has been found that the CBs are leaking as a family from "O" ring seals on the drive shafts. A program was initiated to monitor the oil levels in all of these CBs urgently and replace all seals. As of 2013, all of the CBs on JEN have had their seals replaced. The maintenance plans for the CBs have been reviewed. In addition, this asset is no longer supported by the manufacturer, and some spare components, such as spring wind motors and oil level indicators, are non-existent.

Following a recent switchgear replacement project at FE, the single Sprecher & Schuh HPTw306 22kV CB has been retained as a spare. The FW circuit breakers will be replaced in 2025.

The NH and CS switchgear will be replaced in the next regulatory period.

Sprecher & Schuh HPTw306 22kV Metal clad Buses

In 2016, partial discharge (PD) was detected on switchboards at NH and CS during routine PD testing. An intrusive inspection was carried out subsequently, and it was identified that there was visible PD damage on 22kV busbars and standoff insulators. The switchboards may have non-OEM modifications made to them at the time of installation;. However, this is not certain; these modifications included PVC covers over bus bar connections to increase BIL and the addition of plastic barrier boards to shield LV CT from the HV busbar connections. The cause of PD on stand-off insulators can be attributed to there being no air gap between the PVC covers and the solid insulation, especially around exposed copper busbar conductors. In the absence of design documentation detailing the extent of non-OEM medications on the switchboards, the options to rectify the defects are limited. The PD damage at both CS and NH has been cleaned up, and the switchboard has been reinstated. The renewal of the HV insulation of the 22kV buses in both zone sub-CS and NH has been investigated to mitigate the PD issues. A project will be prepared to replace the PVC covers with HV Raychem heat shrink tape and mastic putty in the affected areas. Periodic condition monitoring on these switchboards has been scheduled in SAP. This includes six monthly online and four yearly offline condition testing.

This switchgear above is recommended for targeted replacement, as it is aged (condition) and non-arc fault rated.

SCHNEIDER AD4/SF-1

Arc fault explosion barriers for the No.1 & No. 2 22kV buses at BY are shared, and there is no physical separation between the two. There were concerns that any fault in the No.1 22kV bus, CBs or CT chambers might vent into the No.2 22kV bus arc chamber and vice versa. Discussions have been held with Schneider, and they have demonstrated and assured that this will not have any impact on the safety of the personnel working on any section of the bus while the other one is still live. A written statement of fact has been obtained from Schneider. A risk assessment was conducted using asset strategy and involving all the relevant stakeholders. Work practices will prepare relevant work instructions to ensure all precautions are undertaken when working on the bus and cable chambers for the 22kV switchboard.

The operation of the bus shutters requires access procedures to be developed as the mechanism needs to be disconnected for independent operation. Asset Management, Services & Projects and Work Practices are working in conjunction to quantify the risks and prepare relevant work instructions.

Siemens Simoprime A4

Siemens contact JEN on 11/09/2022 as follows:-

- Siemens recently repeated the type test, which identified potential issues due to missing parts. Arc Horn Plate and Felt/Gasket;
- There have been no recorded in-service failures;
- Siemens will install the missing parts as a program;
- JEN has communicated the issue to all service and maintenance personnel;
- JEN has installed warning signs and restrictions regarding access;
- If any person is required to access any Switchroom with the panels, they will be required to Arc Flash Rated PPE – Category 4;

- The affected sites include EPN, NS, NT, SBY, SHM and YVE.

Siemens 8BK20 bus failure at ZSS NH

Siemens 22kV Switchboard failure occurred on 18/09/2020. The root cause was attributed to the incorrect thermostat setting for the humidity control heater, which resulted in excessive partial discharge and developed into a phase to ground fault. A program is in place to assess the operation of all metal clad switchgear heaters annually and confirm the controller setting is up to standard.

Siemens 3AF 22kV CBs

In 2015, partial discharge (PD) was detected on the switchboard at TH during routine PD testing. Subsequently, an intrusive inspection was carried out, and it was identified that there was visible PD damage on the No.1 22kV bus; the PD damage was identified across the 22kV bus side fixed isolating contacts and across all circuit breaker isolating contacts.

The metallic fasteners (i.e. bolts, washers and nuts) used to secure the shutter mechanisms to the fibreglass barrier boards are the cause of the PD. The metallic fasteners are not connected to either a live part or ground and are, therefore, floating. Siemens recommended replacing the metallic fasteners (i.e. bolts, washers and nuts) with an isolating material (i.e. Nylon type 66 materials). Fully operational anti-condensation heaters are absolutely critical to prevent PD tracking, not only on this type of switchgear but all switchgear.

The PD damage has been rectified and the metal fasteners have been replaced with nylon. Periodic condition monitoring on these switchboards has been scheduled in SAP. This includes 6 monthly online and 4 yearly offline condition testing.

Furthermore, a family of 3AF CB have been installed within outdoor cubicles at ZSS CN. Both the 3AF CBs and CN and TH have experienced delayed tripping events resulting in upstream protection operating. Although corrective action and modifications have taken place, with some degree of certainty, failure to trip is a significant risk for customers, including life support customers. The 3AF switchgear is non arc fault rated and is planned for replacement.

Non ARC Fault rated switchgear

Following the advice from Siemens regarding the Simoprome A4 switchgear described above, it was deemed prudent to evaluate employee safety when operating older switchgear which was not originally type tested for arc containment by the manufacturer. This evaluation involved various people from JEN and external contractor and a risk assessment has been prepared. Incident energy calculations were prepared as a precursor to a formal Arc Flash Study. The Arc Flash Study commenced in 2024.

The risk assessment focused on a fault within indoor metal clad switchgear when performing planned switching operations that has not been designed for arc fault containment. The resulting fault gases and hot particles escape, causing oil fire and damage to other equipment installed in the vicinity and extended loss of supply. The affected sites considered and assets have been listed below:

- EP: English Electric Type OLX, Email Type J18
- CS & NH: Sprecher and Schuh fitted with Type HPTw306 CBs
- FW: Metropolitan Vickers Type SB14
- TH: Siemens fitted with Type 3AF CBs
- ST: Brown Boveri Type HB24

Specific PPE has been evaluated when operating the above-mentioned switchgear, and exclusion zones have been prepared where required for access to undertake maintenance activities.

Older switchboards (typically with BO CBs) are not designed for arc fault containment, while newer (late 1970s onwards) switchboards, including some older Vacuum and SF6 circuit breakers, may comply with superseded standards. This switchgear above is recommended for targeted replacement, as it is aged and non-arc fault-rated.

1.8.3.2.1 Sump Pump Fail Alarms

Sump pumps are installed in pits under the metal clad switchgear to remove any water that leaks through the cable conduits. These conduits are difficult to seal and, therefore, water entry into the cable pits can impact on the reliability of the switchgear. The sump pumps are inspected annually for functional operation. However, in the event that one of these pumps fails, there is no alarm to indicate its failure. A good asset management practice is to install a water level alarm (sump pump fail alarm) to detect abnormally high water levels. There is no room on the existing alarm panel at both Sub FF and Sub NT for the implementation of a new sump pump alarm. A new alarm panel or local alarm light on the wall is needed to connect to the remote alarm. The primary design standard has been updated to reflect this requirement, and a new HV conduit sealing product has been introduced for all new and existing installations. A program is recommended to retrofit and seal all HV cable conduits in switch room basements.

1.8.3.2.2 Circuit Breaker and Bushing Replacements

Prior to installing any replacement circuit breaker bushings, electrical tests (DDF, PD, IR) will be undertaken to confirm their serviceability. This fundamental applies to all spare and future circuit breakers and includes HV testing.

1.8.3.2.3 Bushing Storage

It is important to cover the bushing stem with an oil-filled tube for long-term storage. This needs to be implemented to avoid moisture ingress, and mechanical damage and prolong the bushing insulation at a serviceable level. A new hot room has been installed and is now operational at the Tullamarine Depot for the optimal storage of bushings.

1.8.3.2.4 Arc Fault Venting Metal clad Switchgear External to Buildings

In support of this initiative, the Electricity Safety Act requires a major electricity company (including JEN) to design, construct, operate, maintain and decommission its supply network to minimise, as far as practicable. By venting all new metal clad switchgear externally to buildings provides an opportunity for JEN to remove the risk of a person being exposed to gas (the composition of the vented gas is unknown) that is, under the current design, vented into the Switch Room. Once the design has been finalised, all AMS requirements will be prepared and further expanded in this document. A Field Technical Change (FTC) process is required to be prepared and the primary design standard updated.

Electric arc flash is a serious hazard that can cause personnel injury, equipment damage, and loss of business objectives. Consequently, there is a need for increased awareness and education within the Energy Industry to eliminate or minimise the risk of injury to persons from an arc flash.

JEN recommends conducting an arc flash study to provide an effective hazard management process and set of recommended practices for applications where electrical arc flash hazards may be encountered in the construction, operation, and maintenance of electrical apparatus.

1.8.3.2.5 Siemens Simoprime A4 Switchgear

The SIMOPRIME A4, 24kV, is a factory-assembled, type-tested switchgear manufactured with an internal Arc Horn Plate and Felt/Gasket to provide a door seal.

The manufacturer conducted a recent repeated type test, and Siemens identified a potential issue regarding the panel's internal arc protection. The manufacturer has omitted these major items from all

Simoprime A4 products installed at JEN. JEN is working with Siemens to retrofit the missing components. A risk assessment and safety alert have been prepared to access these assets.

1.8.3.2.6 SF6 Gas Leakage

Over time, SF6 gas-filled circuit breakers may lose some pressure at a rate advised by the manufacturer that is in line with Australian and international standards and will need to be topped up. Low gas alarms are monitored, and the frequency of leakages will determine a course of action other than a simple top-up. JEN report greenhouse gas emissions annually as part of the National Greenhouse and Energy Reporting (NGER) Act.

Jemena has developed a climate transition plan (CTP). The CTP objectives include delivering safe, reliable, affordable energy and sustainable performance for all as assets and the business transition to enable a resilient energy future. The CTP Transition Plan provides the framework to achieve strategic and climate goals to be a low (zero) carbon entity. The next phase is to develop an Emissions Reduction Plan and roadmap to achieve interim targets.

1.8.3.2.7 Other Issues

The augmentation of the transmission system by SP AusNet has resulted in increased fault levels at zone substations. The interrupting capability of CBs has to be monitored in light of these increasing fault levels to ensure that the interrupting capability of the CBs is adequate.

1.8.4 UTILISATION

Circuit breakers installed across JEN zone substations are power-switching devices that selectively control the energisation of electricity distribution equipment and are highly utilised assets. Circuit breakers play a paramount role in the safe and reliable operation of the electrical distribution network as they are used to rapidly disconnect network faults and provide controlled isolation of sections of the distribution network. The safe and reliable operation of the circuit breaker fleet is vital to network operation as they play an essential role in limiting the risks posed to the public, personnel and equipment. The consequence of an in-service failure varies from supply interruptions, environmental damage, fire start and related safety issues to wide-ranging supply interruptions to a large portion of the network.

All CBs must be operated within their normal current rating and also within their fault interrupting and fault current carrying capacity. Loading and fault current levels due to changes in the upstream transmission systems are monitored to check CBs/switchgear is capable of operating at the required levels.

1.8.5 CONTROL EFFECTIVENESS

Controls employed are identified in Section 1.8.6.4 and 1.8.6.6 and condition based replacements completed are listed in Section 1.8.6.8. These have been employed to manage the identified risks.

The following table assesses the effectiveness of the existing controls by comparing identified risks and measuring past incidents.

Table 4-29: Effectiveness of Existing Controls

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Circuit breaker or bushing explosive rupture failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed and further identified	Nil

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Regulatory & compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Slow trip of 345GC 22 kV CB caused loss of half of all customers at AW. Slow trip of 345GC at BD – no customer interruption.

1.8.6 LIFE CYCLE MANAGEMENT

Specific aspects of the asset strategy involve information about:

- asset lifecycle management options;
- asset creation (including asset acquisition and asset spares);
- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring); and
- asset replacement and disposal.

1.8.6.1 *Lifecycle management options*

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The preferred asset lifecycle management option involves condition monitoring and preventive maintenance, with the aim of achieving at least 50 years of asset life before replacement.

There are 3 feasible lifecycle management options:

- Condition monitoring and preventive maintenance, with condition and risk based replacement. Correctly loaded and adequately maintained, a circuit breaker's life expectancy can exceed 50 years;
- Preventive maintenance with fixed, age-based replacement (irrespective of condition). This option is not considered to be cost-effective, as condition monitoring can be more optimally employed to defer capital replacement based on risk assessments; and
- Corrective maintenance and run-to-failure replacement. This is not a realistic option due to the criticality of the assets (circuit breakers), the long lead-time for replacement, the significant cost of carrying several system spares health & safety risks and continuity of supply to customers risk.

1.8.6.2 *Lifecycle management Scenarios*

The current asset strategy, involving adequate monitoring and maintenance together with condition— and risk-based replacement, is the best option for achieving life expectancies in excess of 50 years.

1.8.6.3 *Asset Creation*

Circuit breaker assets are effectively created via acquisition, upgrades or replacement. The new 11/22kV CBs shall be vacuum and new 66kV CBs shall be SF6. This requirement is in line with current modern standards and good industry practice.

Circuit breakers and switchgear are typically purchased under period contracts in alignment with the primary plant design manual and specification requirements. Incorporation of the elements of this document, particularly opportunities for future improvements, will determine requirements of plant specification.

1.8.6.4 *Asset Operation and Maintenance*

This section provides information about the asset maintenance program, including inspection and testing, preventive maintenance, and reactive and corrective maintenance.

1.8.6.4.1 Circuit Breaker Inspection and Testing

Operators visually inspect circuit breakers when visiting substations. Engineers conduct whole substation audits annually, identifying any obvious defects.

Thermographic surveys are conducted annually and cover all zone substation electrical assets (Refer to the JEN Line Inspection Manual).

Annual Kelman/Camlin (Trip time measurement) testing of all 66kV, 22kV, 11kV and 6.6kV oil CBs has been scheduled in SAP. Whereas annual trip time measurement is performed on selected SF6 gas and vacuum CBs. It is recommended that this testing strategy be reviewed in SAP and that ALL SF6 and Vacuum circuit breakers be tested. In addition, during CB maintenance, a Doble time travel test is performed as stipulated in the Standard Maintenance Instruction (SMI).

On-line Transient Earth Voltage (TEV) and Partial Discharge (PD) tests are conducted annually on all metal-enclosed switchboard cubicles. The switchboards at FW, TH, CS, and NH are tested every six months.

Offline, more extensive DLA and PD tests are conducted on all switchboard buses and CB bushings over 30-40 years old every 5 years.

The bushings of 66 kV LG4C CBs and 22kV 345GC CBs also have DLA & PD tests applied every 5 years.

1.8.6.4.2 Circuit Breaker Preventive Maintenance

(a) Basic Philosophy

The basic philosophy is that CBs should only be maintained when necessary. This is a simple philosophy, but it is not easy to achieve in practice. Preventive maintenance should only be performed when the condition of the CB indicates that maintenance is required.

Three condition indicators are used to assess the condition of any particular CB and determine when maintenance is necessary. Fault interruption duty, the number of switching operations performed, and elapsed time are used to determine when maintenance should be carried out. In addition, new techniques are being tried to give improved condition data.

To determine mechanism operating reliability, a trip/close coil monitor (Kelman/Camlin) instrument is being used to record current versus time information. From this information, slow operation can be detected. In the future, it is planned to capture the first operation at scheduled maintenance and, for CBs with some history of problems, record at intervals between maintenance.

In addition, a functional check is to be performed on each circuit breaker annually (open–close operation) if the CB has not been operated during this period. Many circuit breakers are not called on to operate for extended periods, and this functional test will check the control systems from the control room to the circuit breaker and, in addition, exercise the lubrication on the circuit breaker mechanism and thus reduce the likelihood of slow or sticking operation.

(b) Guideline Documents

This philosophy is documented in two documents as follows:

- Tabulation of Zone Substation circuit breakers with operations limits and default time periods to initiate routine maintenance; Doc No. ELE AM GU 0012 (Draft); and

- Circuit breaker auto point system (after automatic protection operations) classification for maintenance; Doc No. ELE AM GU 0013 (Draft).

These documents describe the criteria for determining when maintenance should be carried out on CB interrupters after a certain fault interrupting duty.

The Guidance documents above, the RCM final implementation report, and the SAP PM document circuit breaker routine maintenance in detail. These documents describe the criteria for CB operating mechanism maintenance intervals and the maximum time interval between interrupter maintenance.

(c) Scope of Documents

These guidance documents were updated to reflect an improved CB tabulation for the allocation of auto points. It covers a method of determining and recording the fault interruption duty carried out by any particular CB by allocating a number of points to each CB after a fault operation. The number of points is determined from the number of fully rated faults the CB is capable of interrupting, the fault level at the station, the location of the fault, i.e., whether at the station or a known distance from the station and whether the fault is three phases or a phase to earth fault.

The sum of the number of allowable faults at rated duty is equated to 100 points. When the accumulated number of points for a particular CB reaches 100 points, the CB contacts and arc control devices, etc. require maintenance.

The SAP PM records the number of normal load-switching operations allowed for each CB type. Time-based maintenance is essential to address the degradation of mechanism lubricants and seals. The requirement for time-based maintenance is documented in the RCM implementation report and the SAP PM.

(d) Classes of Maintenance

For certain types and makes of circuit breakers, experience has shown that it is necessary to service operating mechanisms and auxiliaries more frequently than the primary contact systems and that other components, such as seals, only require replacement at infrequent intervals. Experience locally and overseas has also shown that most failures occur in the mechanisms and auxiliaries. Therefore a greater emphasis must be placed on servicing these components.

For these reasons a substantial number of circuit breakers at present have two Classes of service in the maintenance program.

Class 1 Service — a service of the mechanism (without dismantling) and auxiliaries and the performance of diagnostic testing. The results of the diagnostic tests will indicate whether the scope of work at the service will need to be increased.

Class 2 Service — includes all the Class 1 work plus interrupter servicing or replacement and limited dismantling for lubrication of the mechanism as detailed in the relevant Standard Maintenance Instruction. The majority of the bulk and minimum oil (old generation type) circuit breakers have Class 1 & Class 2 services performed at more frequent intervals than vacuum and SF6 CBs (primarily known as low maintenance types).

Vacuum interrupting chambers do not require any maintenance on the contacts and are sealed for life. The service duty on the vacuum interrupters will be assessed to determine their need for replacement. SF6 interrupters, however, can be serviced. The manufacturer recommends reconditioning SF6 breakers after 5000 to 10,000 operations and requires the dismantling of the sealed interrupting chamber. This has not been included in the scope of the documents above. The reconditioning would require specifically trained personnel, manufacturer’s expertise and spare parts to carry out the work. Moreover, a circuit breaker may not reach the 5000 – 10000 CO operations limit in its life time to warrant any reconditioning.

The following table lists the maintenance triggers for metal clad buses and circuit breakers as implemented in the SAP PM MMS.

Table 4-30: Circuit Breaker Maintenance Intervals

Asset	Maintenance Strategy	Maintenance package
Metal clad buses – air insulated	Time based	≤ 6 years for new buses initially & known bus defects
Metal clad buses – air insulated	Time based	≤ 8 years
Metal clad, Feeder & Cap OCBs - Various	Time and Condition	8Y Class 2, After Auto and/or Service Operations
Metal clad, Transf & B/T OCBs	Time and Condition	6Y Class 2, After Auto
Metal clad, Transf & B/T VCBs	Time and Condition	6Y Class 1, After Auto
Metal clad, Feeder & Cap VCBs	Time and Condition	8Y Class 1, After Auto and/or Service Operations
Metal clad, Transf & B/T SF6 CBs	Time and Condition	6Y Class 1, After Auto
Metal clad, Feeder & Cap SF6 CBs	Time and Condition	8Y, After Auto and/or Service Operations
ABB VD4 CBs (& Bus)	Time and Condition	4Y Class 2, After Auto and/or Service Operations
Outdoor 22kV OCBs	Time and Condition	6Y Class 2, generally 345GC CBs After Auto and/or Service Operations
Outdoor 22kV VCBs	Time and Condition	6Y Class 1 After Auto and/or Service Operations
Outdoor 66kV OCBs (HKEYC & HLE)	Time and Condition	6Y Class 2, After Auto
Outdoor 66kV OCBs (LG4C & HLC)	Time and Condition	6Y Class 1, 12Y Class 2, After Auto
Outdoor 66kV SF6 CBs	Time and Condition	6Y Class 1 After Auto and/or Service Operations
Metal clad bus condition testing	Time	5 years
LG4C and 345GC bushing tests	Time	5 years
TEV/PD tests on ZSS	Time	1 year

The maintenance intervals specified in the above documents will be continually reviewed based on feedback of condition found during maintenance. This continual evolution and refinement is intended to optimise maintenance intervals and practices. This relies on the use of a well maintained and managed maintenance management system.

A new development to be assessed is the progressive introduction of fault monitors that measure and accumulate actual fault currents interrupted by CBs. Modern day protection relays have in-built functionality to record the fault current interrupted by the circuit breaker. An initiative currently being considered is to fine-tune the timing of maintenance of CBs after fault interruption duty. These features, now readily available in multi-function protection relays, can be integrated into our plan for greater remote control and monitoring, enabling real time data to be brought back to a central Control Centre.

1.8.6.5 *Circuit Breaker Reactive and Corrective Maintenance*

Repair of faults in CBs will be carried out as they occur. Any defects that are discovered during inspections or routine preventive maintenance shall be scheduled for repair at a ~~an~~ opportunistic time appropriate to the severity of the defect. Reactive and corrective maintenance is carried out when faults occur or after inspection has identified faults (or both).

1.8.6.5.1 Fault response and repair strategy

The fault response and repair strategy for this asset class involves site attendance by JEN's fault response crew within the hour. Repairs of the failed equipment depend on a number of factors, such as:

- type and extent of damage;
- complexity of repairs; and
- availability of spare components.

1.8.6.6 *Condition-based monitoring*

For all indoor switchboards, a comprehensive set of condition monitoring tests (Insulation Resistance, Partial Discharge, Dielectric Dissipation Factor and Capacitance) shall be conducted on the fixed cubicle buses. These tests are to be conducted at 5 yearly intervals unless condition issues are identified as a result of testing. In this case, tests shall be conducted at more frequent intervals.

In addition to these tests on-line non-disruptive monitoring surveys of circuit breaker and switchboard condition are to be undertaken on an annual basis. These surveys shall include the measurement of Transient Earth Voltages (**TEV**) and Partial Discharge (PD) within metal enclosed switchgear in service, ultrasonic detection, and UHF detection of air borne partial discharge signals. Any switchgear that shows high readings shall then be subjected to the more comprehensive test described above. These tests shall be applied to all indoor and outdoor switchgear where appropriate irrespective of age.

1.8.6.7 *Circuit Breaker Future Improvements*

JEN's technology strategy involves investigating new technologies to improve network reliability, safety, environmental care, and reduce costs. Future improvements being explored for this asset class involve the following:

- DLA testing of all Email 345GC 22kV CB bushings;
- SF6 and Vacuum CB timing travel and trip checks using the new Doble TDR test set;
- Online condition monitoring for critical circuit breakers and switchboards;
- All CB'sincluding SF6 and Vacuum CBs should be tested annually (functional testing and Kalman trip time testing) for tripping and closing times to identify slow performing circuit breakers. It is recommended to schedule this work;
- As indoor switchboard failures is a catastrophic event, resulting in significant impact to supply availability, a modular switchroom fitted with HV switchboard and protection should be purchase to mitigate this risk. In the same way, further consideration for a spare modular control room is recommended;

- A fully enclosed 66kV SF6 Gas Insulated System (GIS) will be introduced at the future ZSS NDC, primarily due to customer space constraints. A double busbar system has now been adopted as a JEN standard to maintain supply continuity for the customer and maintain a closed 66kV subtransmission loop for JEN's connected zone substations in the event of a single GIS bus failure. In general terms, subtransmission feeder CB and transformer CB Bays are connected to each of the 66kV buses with internal isolators and earth switches. This is a convenient and compact modular design that can be expanded to accommodate the customer and JEN's requirements. A Risk Assessment was prepared to evaluate the Constructability, Operability and Maintainability (COM), of the new GIS system. A specification has been prepared and a supplier selected for the GIS System. It is recommended to further consider purchasing a spare GIS bay to mitigate failure risk, before the switchgear is discontinued and no longer supported by the manufacturer.

- In the future, a greener gas alternative to SF6 will also be considered. For further information and design features, refer to the JEN GIS specification. Currently, the European market is phasing out SF6 in new HV circuit breakers and GIS.

- New developments has provided an alternative to SF6 live tank or dead tank 66kV circuit breakers in the market place. Vacuum technology for 66kV circuit breakers is available and should be considered. It is preferential for vacuum dead tank CBs to be purchased over live tank CBs.

- Following recent issues identified with the ABB ABBACUS capacitor banks(external to JEN), Siemens Simoprime A4 metal clad switchgear, aging switchgear which is not arc fault rated, and the blue book new requirement for arc flash study, JEN has formed a working group to assess the risk to employees when working in HV and LV environments.

- Arc fault detection: Optical arc flash sensing of electrical faults is a technology currently available to minimise fault damage and potentially provided a safer workplace. The arc fault detection provides faster fault clearance time and is interlocked with a current check relay. This system is recommended for assessment and possible retrofitting. Similarly, this could be included in the switchgear specification and modular capacitor bank enclosures.

- Vacuum interrupters (Bottles) have been in service since 1982 at ZSS TH, and several units are installed throughout the JEN zone substations. To maintain the performance, safety, and reliability of these CBs, a periodic vacuum condition HV test is recommended.

- Bushing storage: To avoid moisture ingress and mechanical damage, the bushing stem should be covered with an oil-filled tube during storage. A hot room has been installed and is now operational at the Tullamarine Depot for optimal storage.

- Annual Kelman/Camlin (Trip time measurement) testing of all 66kV, 22kV, 11kV and 6.6kV oil CBs has been scheduled in SAP. Whereas annual trip time measurement is performed on selected SF6 gas and vacuum CBs. It is recommended to review this testing strategy in SAP and undertake testing of ALL SF6 and Vacuum circuit breakers. In addition, during CB maintenance, a Doble time travel test is performed as stipulated in the Standard Maintenance Instruction (SMI).

- Modern CB management relays have the capability to record CB trip times. Routine downloads and engineering assessment utilising artificial intelligence (Machine Learning) to report trip time exceedance is recommended to supplement the Kelman/Camlin (Trip time measurement).

- It is recommended to reassess the RCM analysis conducted back in 2000 to now follow the IEC 60300 0-3-11,12 and 14 RCM guidelines and quantitatively determine the maintenance intervals for all sub-asset classes.

- Lubrication selection for all mechanical devices such as for circuit breakers, disconnectors, isolator and earthing switches, and transformer mechanisms is critical. The application of lubrication must follow approved guidelines to maintain performance, and reliability. A contractor has been engaged to prepare a lubrication report on behalf of JEN. The report titled: "Risk Assessment Methodology for Application of New Switchgear Lubricant" is currently being reviewed. Pending the final report, it should be recommended for trial application on ZSS assets.

The new lubricant under consideration is provided by the United States (U.S.) based company [redacted] and it is intended that JEN use it as a single replacement for the majority of other lubricants currently in use. [redacted] market the product as MDL and it is provided in a kit.

The results obtained from the investigation into the application of new lubricants and the risks associated with changing to the [redacted] product range appears to be positive.

- The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

1.8.6.8 *Asset Replacement/Disposal*

Replacement of zone substation circuit breakers is initiated when all efficient cost maintenance and life extension options have been considered and condition monitoring has indicated that the circuit breaker has an unacceptable risk of failing electrically, thermally or mechanically and the deterioration trend cannot be halted or reversed.

While planned circuit breaker replacement is determined and prioritised based on ongoing test results, budget constraints and other network requirements (such as capacity constraints) is also considered. Whilst individual lifecycle management plans determine anticipated expenditure on a specific asset class, various asset classes will compete for the available funding.

A project prioritisation process ranks projects proposed for inclusion in the annual capital works program. This process forms part of a quantified framework for applying specific risk management techniques and methodology to the development of the wider capital works program, and the principles of this approach articulate how JEN prioritises and optimises its investments.

More broadly, JEN looks at the specific asset drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-31 provides an overview of the circuit breaker specific drivers of the proposed replacement volumes and expenditure.

Table 4-31: Circuit Breaker Specific Drivers

Driver	Risk/Opportunity Description	Consequence
Asset integrity, health, safety and environment	Circuit breakers experiencing tripping defects (slow operation, mal-operation etc.)	Failure to fulfil critical network functions that could cause significant numbers of customers off supply (i.e. Zone substation protection tripping) Failure to isolate properly causing safety risks Failure to interrupt fault currents
Asset integrity	Increased operational duty of some circuit breakers	Will cause mechanical failure of the primary contact drive systems and lead to reduced asset life (particularly caused in the case of Zone substation Capacitor bank CB installations that are operated on a daily basis)
Asset integrity, health, safety and environment,	Leaking insulating compound on some CB bushings	Will cause failure if unattended, leading to interruption of supply to customers.

Driver	Risk/Opportunity Description	Consequence
regulatory compliance		
Asset integrity	Some CB types have been identified as suffering age-related deterioration of the insulating systems (related to synthetic resin bonded paper bushings)	Failure may lead to customer supply interruption.
Asset integrity, health, safety and environment	Increasing fault levels at zone substations needs to be monitored to ensure that the interruption capability of the CBs are adequate	Inadequate CBs causing supply, fault current interruption, safety and other risks.

Historical capital expenditure

Table 4-32 lists information about circuit breaker replacement for the period 2005 to 2022.

Table 4-32: Circuit Breaker Replacement History from 2005 to 2022

Year	Qty.	ZSS	Type	Reason for Replacement
2005	17	NS	GEC K5	Bus pitch leak, spring charged CB mechanism defects.
2006	6	YTS	GE FHK039	Retirement of 6.6kV Distribution voltage.
2007	18	FF	Reyrolle C6T	Pitch filled bus, spring charged CB mechanism defects.
2007	1	P	EE OLX	Converted to vacuum interrupter.
2008	2	SBY/YTS	Crompton Greaves	Replaced seals due to gas leaks.
2009	17	NT	Reyrolle A2T	Pitch filled bus. Aged asset.
2010/11	15	HB	Email J18	Aged asset. Deteriorated condition from test results.
2011/12	14	PV	EE OLX	Aged asset. Deteriorated condition from test results.
2012	2	PV	GEC LG4C	Aged asset. Failure history, deteriorated bushings and mechanism problems.
2012/13	2	YTS	Reyrolle OS10	Aged asset. Part of retirement program.
2012/13	3	YTS	Reyrolle OS10	Planned Retirement of YTS.
2012/13	19	YTS	WR 345GC	Planned Retirement of YTS.
2012/13	16	ES	Reyrolle LMT	Aged asset. Deteriorated condition from test results.
2014	1	BD	ABB VBF36	Deteriorated condition from test results.
2015	8	ST	SACE HA1	Deteriorated interrupter condition.
2015	1	ES	ASEA HKEYC	Aged asset. Spares required.
2017	3	AW	GEC /MV LG4C	Aged asset. Failure history, deteriorated bushings and mechanism problems.

Year	Qty.	ZSS	Type	Reason for Replacement
2017	19	P	EE OLX & 66kV HKEYC	Aged asset. Deteriorated condition. Retired as part of network augmentation project – ZSS P retired & has been redeveloped as PTN).
2018	15	FT	Email J18	Aged asset. Deteriorated condition from test results.
2018/19	1 1 4 2 2 1	SBY	AEI JB424 Reyrolle OMT3 CG 30 SFGP HPFC409K HLE RMAG	Aged asset. Network augmentation project – costs are part of the ZSS SBY augmentation / upgrade/ full switching project). Note the RMAG and various other CB components have been retained for spares.
2019	2	BD	ASEA HKEYC	Aged asset. Spares required.
2022	1 12 1 1	FE	AEI LG4C MV SB14 S/S HPTw306 Email 345GC	Aged asset. Failure history, deteriorated bushings and mechanism problems.
2022	1	HB	AEI LG4C	Aged asset. Failure history, deteriorated bushings and mechanism problems.

Table 4-33 lists proposed replacements from 2024 to 2030. The CBRM model is utilised to determine the highest priority CBs/switchgear in need of replacement and the table below shows the replacement volume. They are prioritised based on ongoing test results and network requirements such as capacity constraints.

Table 4-32 shows that historically 208 circuit breakers were replaced between 2005 and 2022.

In line with the CBRM model and known asset condition issues the proposed circuit breaker replacement is shown in table 4-29 below:

Table 4-33: Proposed Circuit Breaker Replacements from 2024 to 2030

ZSS	Qty.	Type	Estimated Replacement Timeframe	Reasons for Replacement	Comments
HB	1	AEI LG4C	2024	Condition	Aged asset. Failure history, deteriorated bushings and mechanism problems. Business Case approved. Completed
EP	2 1 10 22	AEI LG4C ASEA HKEYC EE OLX Email J18	2025 2029	Condition	Aged asset. Deteriorated condition.11kV J18 & OLX (Not rated for arc fault containment); (Network augmentation project – zone substation EP will be retired and redeveloped as EPN). Retirement during voltage conversion project.

ZSS	Qty.	Type	Estimated Replacement Timeframe	Reasons for Replacement	Comments
FW	18 2 1	MV SB14 AEI LG4C Email/WR 345GC	2025	Condition/age 22kV Bus PD	Replace 22kV switchgear with 3 new 22kV modular switchrooms & new control room Aged asset, including 22kV bus Aged asset. Failure history, deteriorated bushings and mechanism problems. Not rated for arc fault containment.
YVE	1	Crompton & Greaves	2025	Chronic SF6 Gas leakage during winter	This type of CB has a failure history, leaking SF6 into the environment.
YVE	1	N/A	2026	New installation	Install new CB to avoid switching of No.4 transformer via 66kV disconnect switch
AW	1	Crompton Greaves	2026	Condition Reliability	The Crompton and Greaves CB has a failure history. Mechanism had been damaged twice.
BLT	2	Email / WR 345GC	2026	Condition	Replace MB feeder CBs, isolators and surge diverters Aged asset. Failure history, deteriorated bushings and mechanism problems.
CN	1 6 12 1 1	Crompton Greaves Siemens 3AF Email / WR 345GCASEA HLC AEI LG4C	2028	Condition	Replace 22kV switchgear with 3 new 22kV modular switchrooms & new control room Aged asset. Failure history, deteriorated bushings and mechanism problems.
CS	1 11	AEI LG4C Sprecher & Schuh	2029	Condition	22 kV switchboard showing evidence of partial discharge (Not rated for arc fault containment) & 66 kV LG4C Aged asset. Failure history, deteriorated bushings and mechanism problems.
NH	1 13	AEI LG4C Sprecher & Schuh	2031	Condition	22 kV switchboard showing signs of partial discharge (Not rated for arc fault containment) & 66 kV LG4C CB
TH	13	Siemens fitted with Type 3AF CBs	2032	No.1 and No.2 22kV Buses Not rated for arc fault containment.	Non ARC Flash rated
AW	16	Email / WR 345GC	2033	Condition	Replace 22kV switchgear with 4 new 22kV modular switchrooms

ZSS	Qty.	Type	Estimated Replacement Timeframe	Reasons for Replacement	Comments
					Aged asset. Failure history, deteriorated bushings and mechanism problems.
BD	18	Email / WR 345GC	2033	Condition	Replace 22kV switchgear with 4 new 22kV modular switchrooms Failure history, deteriorated bushings and mechanism problems.
NT	1	AEI LG4C	2033	Condition	Replace 66kV LG4C CB
ST	14	Brown Boveri Type HB24	2033	No.1 and No.2 22kV Buses Not rated for arc fault containment.	Non ARC Flash rated

All CBs containing oil are oil sampled as part of the disposal process to determine the level (if any) of PCB contamination so that the insulating liquid can be disposed of appropriately.

CBs containing SF6 gas are disposed of in accordance with EPA requirements.

Any CBs containing asbestos components are disposed to an authorised asbestos contractor.

In some instances where spare parts are not readily available for older CBs, when they are retired or replaced, they shall be retained for spare parts. All other retired and decommissioned CBs are sent to scrap.

1.8.7 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information requirement to achieve JEN's business objectives at the Asset Class. In summary, the combination of JEN's Business Plan, the individual Asset Business Strategy (ABS) and ACS all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives (Table 4-34). *The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-35 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class. Table 4-36 provides the information initiatives required to provide the future information requirements.

All of the information required by the circuit breaker Sub-Asset Class is available within JEN's current business systems.

Table 4-34: Circuit Breaker Business Objectives and Information Requirements

Business Objective	JEN Information Sources	Externally Sourced Data
Maintain safety, availability and reliability of Circuit Breakers	SAP ERP (enterprise resource planning) DrawBridge (drawing management) Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee*. Alerts – from DB's and Government Organisations and manufacturers Manufacturing manuals AS/IEC standards

*The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-35: Circuit Breaker Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Circuit Breaker – Asset Creation	• Specifications and tender responses • Zone Substation Primary Design Standard • New asset project progress reporting. Completion recorded in SAP • Asset register in SAP		• High – Regulated to maintain supply reliability, safety and quality of supply. Also, a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of the Circuit Breaker via inspections and audits	Asset register SAP, with details of each asset and significant components; • Manufacturer • Type • Equipment description • Construction year • Basic specification - Voltage - Current • Location: Zone substation name • Address • Condition Monitoring - Maintenance reports - Test reports • Performance history - Daily situation reports - Investigation reports (ECMS) - Plant defect reports • DrawBridge - Single line diagrams - plant data - OEM manuals	• Migrate Condition & Performance reports/data into SAP to improve analysis and decision making. • Photograph circuit breaker nameplate and attach to SAP equipment. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	- design drawings/layouts • SMI's – (Standard maintenance instruction) • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP		
Maintain functionality of Circuit Breakers via Preventive Maintenance	• Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. • Scheduled task description, timing and completion recorded in SAP; SMIs held in SharePoint, Policies & Forms. • Manufacturers maintenance manuals • SAP notifications and work orders activities performed and components replaced • Details of work completed recorded in SAP • ZSS fault current level calculations • Published Distribution Annual Planning Report available on JEN website • Daily situation reports (email) Stored by JEN Control Room, used to determine fault level interrupted by the CB • ZSS Auto Points table • Details of spare equipment located in SAP • OPEX & CAPEX cost reporting recorded in SAP	• Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. • Connectivity required for ZSS protection relay to SAP for CB wear monitoring and to be used for maintenance planning. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply
Maintain functionality of Circuit Breakers via Condition Monitoring	• Condition monitoring tasks, schedule and results stored in proprietary test equipment database in SAP • Scheduled task description, timing and completion recorded. • Outputs from condition monitoring analysis.	• Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	• High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)

Respond to Circuit Breaker defects / faults to restore equipment operationally. Perform corrective maintenance.	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• Basic specification
	  - Voltage
	  - Current
	• Location: Zone substation name
	• Address
	• SAP notifications and work orders activities performed and components replaced.
	• Details of work completed recorded in SAP
	• Condition Monitoring
	  - Maintenance reports
	  - Test reports
	• Performance history:
	  - Daily situation reports
	  - Investigation reports (ECMS)
	  - Plant defect reports
	• DrawBridge
	  - Single line diagrams
	  - plant data
	  - OEM manuals
	  - design drawings/layouts
	• Asset failure details and investigation reports.
	• Details of spare equipment located in SAP
	• OPEX & CAPEX cost reporting recorded in SAP
		• Although hard copies of manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in in Drawbridge. Manufactures manuals for older assets may not be available.
		• Access all information via electronic tablet in the field.
		• All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.
		• Update asset data in SAP for missing or incorrect data.
			• High: Regulated to maintain supply reliability, safety and quality of supply

Circuit Breaker – CBRM	• CBRM analysis Health Index • Held by Primary Plant	• The CBRM model was initially prepared in 2014. Since this time the model is no longer supported by the original designers of the product.	• High: Regulated to maintain supply reliability, safety and quality of supply
Circuit Breaker – Rating suitable for load demand	• ZSS load forecast in ECMS • Published Distribution Annual Planning Report available on JEN website	• Determine transformer loading guideline	• High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
ACS Review	• Condition data • Fault/failure data • Maintenance & replacement costs • AMS		• Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-36: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph circuit breaker nameplate and attach to SAP equipment Connectivity required for ZSS protection relay to SAP for CB wear monitoring and to be used for maintenance planning Access all information via electronic tablet in the field Update asset data in SAP for missing or incorrect data	To improve analysis and decision making Asset data available from business systems saving on site trips Utilise CB current interrupted recorded in protection relays to determine when maintenance is necessary	Poor efficiency in accessing asset data and possible risk of maintenance inefficiencies	Utilise available data from protection relays in lieu of generic fault level calculations and auto points allocation Asset Data as per RCM and SAP requirements

1.9 ZONE SUBSTATION DISCONNECTORS AND BUSES

1.9.1 INTRODUCTION

The Disconnectors and Buses Strategy applies to HV disconnectors/isolators, buses and associated equipment installed in zone substations. The term Disconnectors and Buses is referred to throughout this document; it is a generic statement which includes the following equipment:

- Disconnectors (including motor operated disconnectors);
- Isolators;
- Earth switches;
- Bus conductors;
- Flexible connections and connectors;
- Surge arresters;
- Wall/floor bushings; and
- Insulators.

This Sub-Class excludes indoor metal clad switchgear. Refer to clause 4.2 Zone Substation Circuit Breakers.

1.9.1.1 *Asset Specification*

Table 4-37 depicts the voltage ratio, the number of high and low tension buses, and, the number of wall bushings installed in the various Zone Substations on the JEN network, including customer substations with JEN assets installed*.

Table 4-37: Bus and wall bushing Information

ZSS	Voltage Ratio (kV)	No. of High Tension Buses	No. of Low Tension Buses	Transfer Bus	No. of Wall Bushings
AW	66/22kV	4	3	Y	N/A
BD	66/22kV	4	3	Y	N/A
BLT(BLTS)*	N/A	N/A	0	N/A	N/A
BMS	66/22kV	3	2	N	N/A
BY	66/22kV	2	2	N	N/A
CN	66/22kV	3	3	Y	N/A
COO	66/22kV	2	2	N	N/A
CS	66/22kV	3	2	N	8
EP	66/6.6kV	3	6	N	N/A
EPN	66/22kV	1	1	N/A	N/A
ES	66/11kV	2	2	N	N/A
FE	66/22kV	2	2	N	N/A
FF	22/6.6kV	6	3	N	N/A
FT	66/11kV	3	3	N	6

ZSS	Voltage Ratio (kV)	No. of High Tension Buses	No. of Low Tension Buses	Transfer Bus	No. of Wall Bushings
FW	66/22kV	3	3	Y	N/A
HB	66/11kV	3	3	N	N/A
MAT*	66/22kV	2	Melbourne Airport's responsibility	N/A	N/A
NEI*	N/A	1	N/A	N/A	N/A
NEL*	66/22kV	2	2	N	N/A
NH	66/22kV	3	3	N	12
NS	22/11kV	3	3	N	N/A
NT	66/22kV	3	3	N	9
PTN	66/22kV	2	2	N	N/A
PV	66/11kV	3	3	N	N/A
SBY	66/22kV	7	3	N	N/A
SHM	66/22kV	2	2	N	N/A
SSS*	N/A	4	N/A	N/A	N/A
ST	66/22kV	3	3	N	24
TH	66/22kV	3	2	N	N/A
TMA	66/22kV	2	2	N	N/A
VCO*	N/A	2	N/A	N/A	N/A
WGT*	N/A	0	N/A	N/A	N/A
YVE	66/22kV	3	4	N	N/A

1.9.1.2 *Population and age profile*

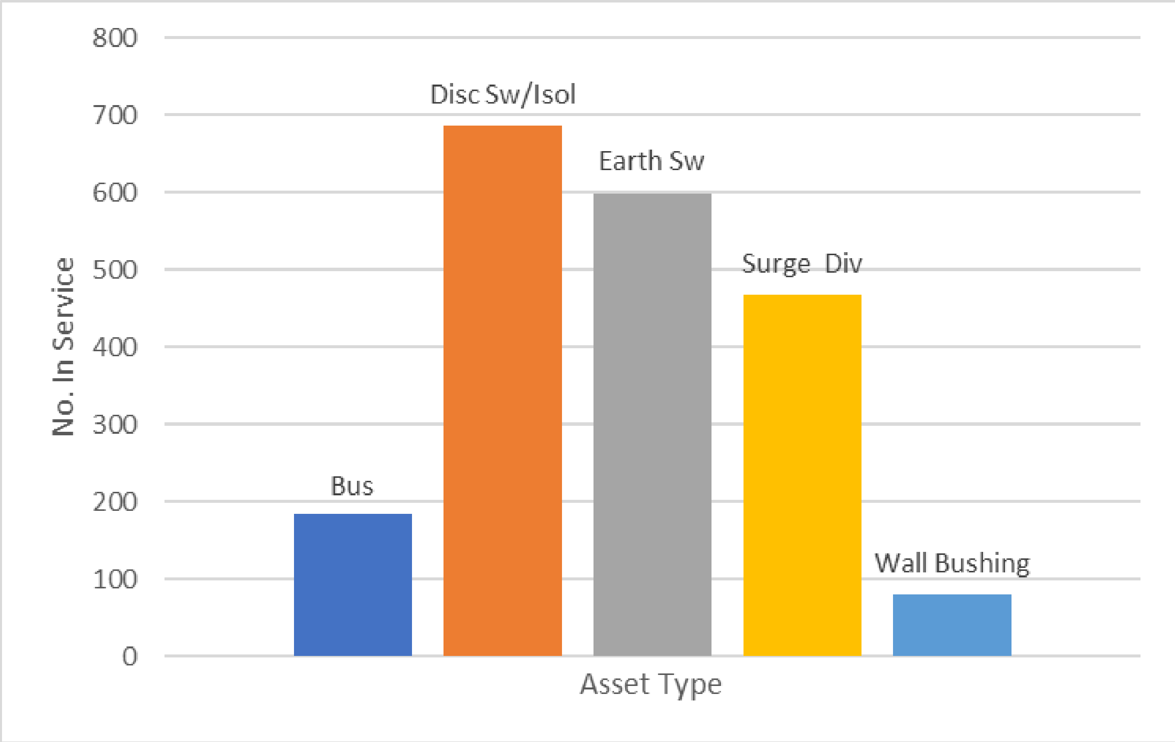
The primary plant population is spread across 26 zone substations and 7 HV customer substations with JEN assets installed[6].

Note: Flexible connections and connectors are not recorded due to their inherit nature. Insulators are not stated because they are generally associated with the equipment they are connected to (i.e. disconnector, bus, circuit breaker etc.).

Figure 4–14 identifies the population of different types of primary plant equipment (i.e. buses, disconnect/Isolator switches, earth switches, surge diverters and wall bushings).

[*] Refer to Appendix K for a list of JEN zone substations and HV customer substations with Jemena assets installed.

Figure 4–14: Asset Population (Dec 2024)



The average age of disconnectors/isolators, earth switches, buses, surge arresters and wall bushings installed on the JEN network is shown in Figure 4–15. Previously disconnectors/isolators and buses had an average age >35 years. Following recent projects new asset populations has increased, and older assets retired from service. The remaining aged assets may require more age related maintenance in the coming years.

Figure 4–15: Average Age of Specific Assets (Dec 2024)

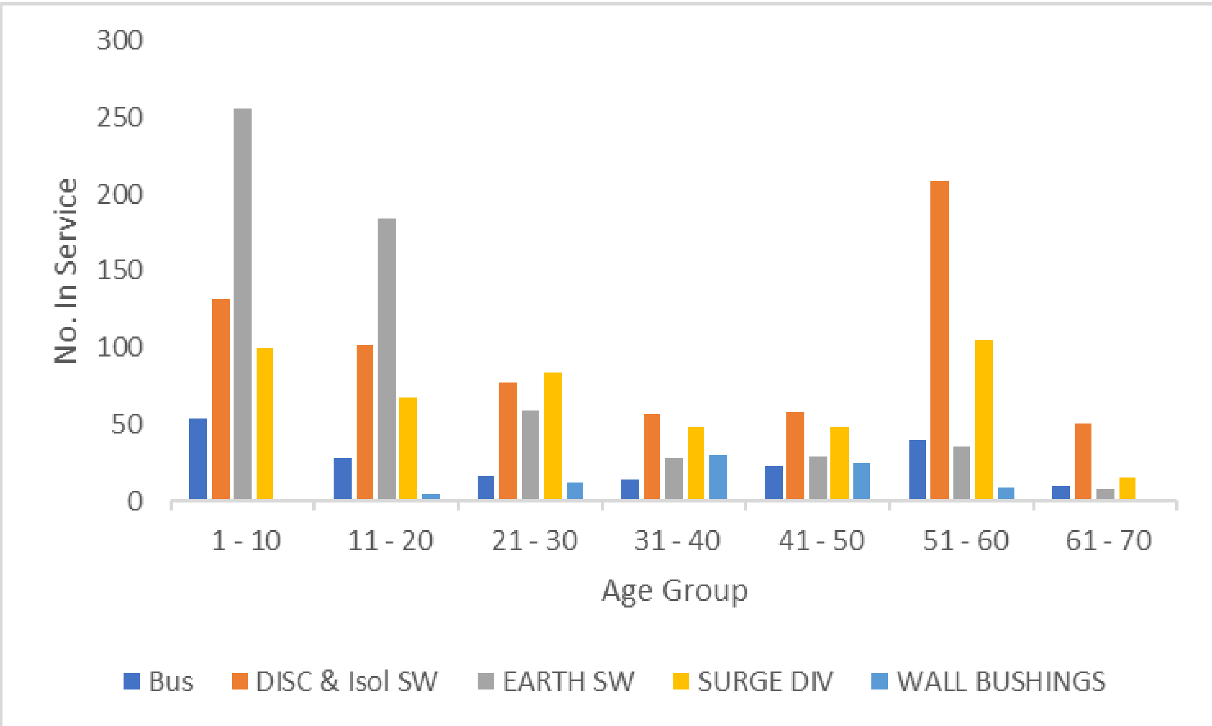
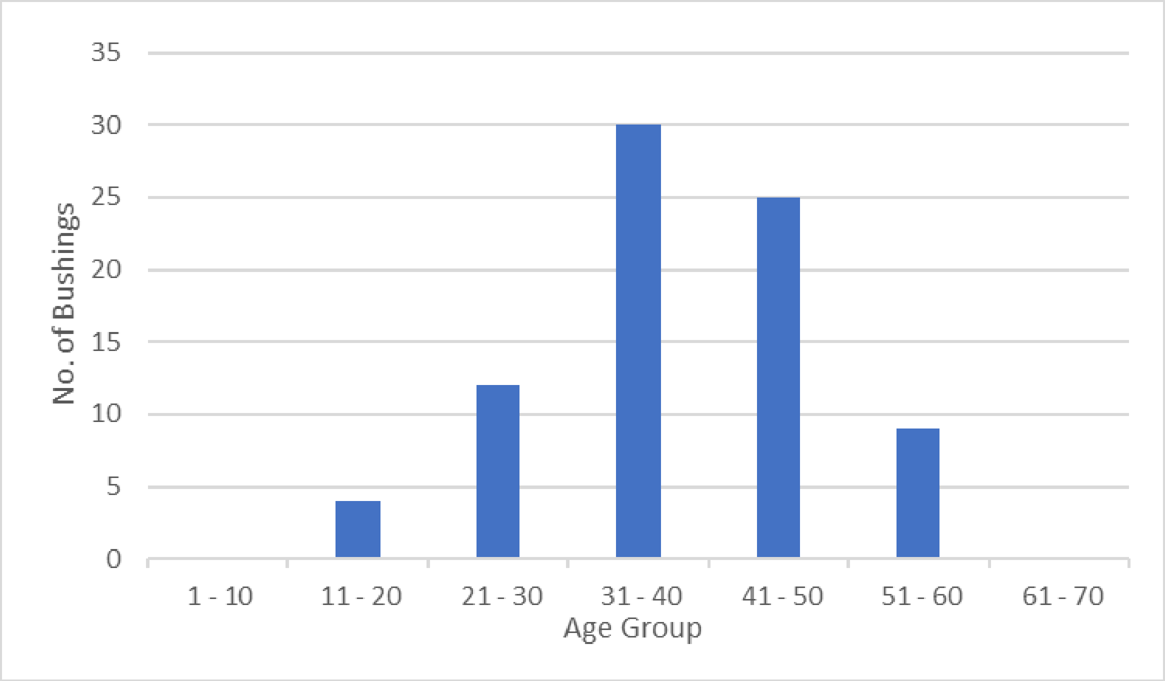


Figure 4–16 shows the age profile of wall bushings in service across the JEN Electricity Network.

Figure 4–16: Wall Bushing Age Profile (Dec 2024)



The oldest wall bushings date back to 1970 and are located at FT. There are 34 bushings that are >40 years old. 80% of the wall bushings on the JEN network are >30 years old.

Wall bushings are difficult to access and historically have not been tested on the JEN network. Due to the aging population a testing program has been initiated. The testing program utilises DDF tests to evaluate bushing condition and determine if any replacement strategies are required. Difficulties in accessing wall bushings due to working at heights has slowed the testing program.

1.9.2 RISK

This chapter includes information about Disconnector and Bus risk profiles involving the way that asset class criticality is established, the risks posed by Disconnector and Bus failure (including the various failure types and their possible consequences), other measures being introduced to manage asset risk, and a list of the various issues currently confronting Disconnectors and Buses.

This information specifically involves:

- Asset class criticality score (sub-asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- CBRM for identifying assets approaching end of life;
- Existing controls;
- Asset Spares;
- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

Buses, disconnectors, isolators and earth switches are generally very reliable and risk of failure is considered to be low. The major risks associated with disconnectors are related to failures due to high resistance connections and insulation breakdown. Failure to maintain a bus, disconnect or earth switch can lead to melting of contacts or connections, arcing and flashover due to insulation degradation and mal-operations of equipment. This can result in total loss of supply to all customers supplied from the zone substation, or equipment failure causing delayed operations.

Traditionally wall bushings have not failed but risk assessments have identified a failure will place a zone substation(s) on single contingency until the sub transmission fault is repaired. Additionally personnel safety is at risk in the event of a failure due to porcelain fragments.

Risks for this asset class and the probability and consequence of these occurring include:

- Regulatory non-conformance (equipment failure), likelihood is rare; consequence additional scrutiny by Regulator is Minor resulting in Low risk;
- Health and safety issues (equipment failure), likelihood is unlikely; consequence person injury is serious resulting in Low risk;
- Environmental issues (equipment failure), likelihood is unlikely; consequence of scattered broken components is minor resulting in Low risk;
- Financial Impact (replacement costs), likelihood is unlikely; consequence of few $k is minor resulting in Low risk;
- Operational (loss of supply), likelihood is rare; consequence of bus outage for several days is major resulting in Moderate risk; and
- Reputational risk, likelihood is rare; consequence of sporadic media/public attention is serious resulting in Low risk.

Specific Disconnector risks include the following in Table 4-38:

Table 4-38: Disconnector drivers and risks

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment	Disconnectors not closing/opening circuit properly	Failure to appropriately isolate plant within stations This presents a high risk to employee safety
Asset Integrity, Health, Safety and Environment	High resistance connections in some families of older bus systems	Failure to appropriately isolate plant within stations This presents a high risk to employee safety
Asset Integrity, Health, Safety and Environment	Issue with latching mechanism in some disconnects, that also have a history of failure	Will cause it to open during heavy loads/while carrying fault current This presents a high risk to employee safety

Emerging risks for this asset class include:

- Ageing population;
- Deteriorating insulation condition of bus insulators disconnector and earth switch insulators, surge arrestor housings;
- Deterioration of disconnector and earth switch operating mechanisms and linkages and contacts;
- Expenditure prioritisation restricting timely replacements;
- Damage due to birds and animals and possibly vandalism;

- Non-availability of components for old disconnectors and earth switches; and
- Moisture ingress and deterioration of non-linear resistor blocks in surge arresters.

1.9.2.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). The results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact the achievement of JEN's operational objectives. This is used to rank the importance of dissimilar sub-asset classes (e.g. transformers and buildings and grounds) to identify areas where risk should be managed first and control measures implemented.

The disconnector and buses has an asset criticality score of AC4 (High) due operational and health and safety consequences associated with failures.

The average zone substation supplies an average 13,065 customers. A typical outdoor zone substation utilises approximately forty 22kV and nine 66kV disconnectors. Therefore, buses and associated equipment are highly critical low volume assets in the distribution network. Zone substation buses and associated equipment criticality is defined by:

- Strategic impact on customer supply (If N-1 is compromised and transfer capability is limited, load shedding may be required); and
- High consequence of failure (loss of supply and OH&S issues).

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures.

For severe disconnector/bus failures that cannot be repaired within 24 hours; the location within the network determines the impact on supply to customers. Table 4-39 demonstrates the various scenarios.

Table 4-39: Potential strategic failures

ZSS Configuration	Failure Item	Protection Trips to Isolate Fault	Status Post Trips	Customer Impact	Failure Category
3 transformer, no 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV B-T CB	1 transf OOS; 2 transf in service	All Customer still on supply	Serious
2 transformer, no 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV B-T CB	1 transf OOS; 1 transf in service	All Customer still on supply	Serious
3 transformer, with 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV line CB	66 kV line OOS; 3 transf still in service	All Customer still on supply	Serious
3 transformer, with 66 kV line CBs	66 kV T1-T2 Bus/disconnector	66 kV line CB & 66 kV B-T CB	1 transf OOS; 2 transf in service	All Customer still on supply	Serious
2 transformer, with 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV line CB	66 kV line OOS; 2 transf still in service	All Customer still on supply	Serious

ZSS Configuration	Failure Item	Protection Trips to Isolate Fault	Status Post Trips	Customer Impact	Failure Category
2 transformer, with 66 kV line CBs	66 kV T1-T2 Bus/disconnector	66 kV line CB & 66 kV B-T CB	1 transf OOS; 1 transf still in service	All Customer still on supply	Serious
3 transformer	22/11 kV Transf side disc/connection	22/11kV Transf CB; 66 kV Line & B-T CBs	1 transf OOS	All Customer still on supply	Serious
3 transformer	22/11 kV Bus/disconnector	22/11 kV Transf CB & 22/11 kV B-T CB	1 Bus OOS	Customers from 1 bus off supply	Serious or Strategic*
3 transformer	22/11 Feeder side Dsc/connection	Feeder CB	1 feeder OOS	Customers from 1 feeder off supply	Serious
2 transformer	22/11 kV Transf side disc/connection	22/11kV Transf CB; 66 kV Line & B-T CBs	1 transf OOS	All Customer still on supply	Serious
2 transformer	22/11 kV Bus/disconnector	22/11 kV Transf CB & 22/11 kV B-T CB	1 bus OOS	Customers from 1 bus off supply	Serious or Strategic*
2 transformer	22/11 Feeder side Disc/connection	Feeder CB	1 feeder OOS	Customers from 1 feeder off supply	Serious

* If repairs or replacement of disconnector/bus system takes more than 24 hours the failure is considered Strategic

Criticality is further assessed for individual disconnectors and buses CBRM. CBRM, which was introduced for JEN disconnectors and buses in 2014, is utilised to predict conditions in the future (Health Indices) and estimate the Probability of Failure. These tools are utilised to indicate required changes to asset management plans, to develop asset investment plans using existing asset data and other information and to determine when end-of-life replacement will be required. Assets with a higher health index score are targeted for further analysis before imminent replacement. For further information on CBRM, its inputs and outputs and methodology, please refer to Appendix K.

1.9.2.2 *Spares*

As part of the criticality assessment, consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002). It was determined that adequate disconnector component spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team.

System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub transmission line due to a component failure.

Critical Spares Assessment Procedure (ELE-999-PR-RM-002) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I.

Furthermore, when assets are retired from service, consideration is given to retaining components or entire assets as spares to service the existing aging fleet.

Wall bushings for Zone Substation ST are stored onsite. Bushings typically have a delivery lead time of 4 to 6 months; therefore, a fleet of spares as per above is vital to maintain network capacity in the event of a failure.

1.9.2.3 *Failure Modes*

Disconnectors and bus systems are critical interconnecting assets installed to fulfil functions associated with the safe and reliable operation of the HV networks. These assets can experience insulation breakdown and operation defects, and in rare circumstances, catastrophic failure can occur.

The dominant disconnector and bus system failure modes that impact on the reliability of the network are as follows:

- failure to insulate due to lightning, over-voltages due to switching, animals and birds or insulation deterioration or pollution;
- failure to carry fault currents;
- failure to carry load due to high resistance connections resulting in thermal overheating; and
- failure to open or close (disconnectors and earth switches) mechanism, linkages or contact problems that prevent the switching device from opening or closing. This will delay isolation for maintenance or fault (disconnectors) or delay applying or removing earth connection (earth switches).

1.9.2.4 *Existing Controls*

The following controls are common to all risks to mitigate exposure to the JEN network:

- Ongoing asset management programs as documented in Section 4.3.3 Performance Factors and Section 4.3.4 Life Cycle Management;
- Ensure completion of programs stated in current strategy; and
- Continue to reinforce JEN internal technical standards.

The availability of spare wall bushings will be reviewed. The aim is to avoid a failure resulting in a single contingency event over a prolonged period because there is no spare wall bushing to put back into service. Two spare sets of bushings to transition between internal HV switch rooms and 66kV line entries will be considered.

Many old disconnectors are no longer manufactured and therefore spares are no longer available. A replacement program allows retired units to replenish these spares.

Some spares have been salvaged from retirement projects and left over from CAPEX projects. The brown pin and caps (66kV) are located at various ZSS, and with the 66kV post insulators in the store. When a failure occurs, a replacement insulator may not be a direct changeover, and spacers may be required to adapt to each installation.

We have 2 sets of spare 66kV surge diverters. A spare set of 22kV SD is recommended.

The contingency plan for these assets is to hold spares for each asset, that is, disconnector, earth switch, surge arrester, busbar insulators. Conductors, cable and terminations are available from general stock holdings.

Various disconnector and insulator spares are available to ensure network reliability.

1.9.3 PERFORMANCE FACTORS

Disconnector and buses are expected to provide their rated normal and fault level current carrying capability as well as HV insulation, isolation switching and earth switching functions when required, for a life time in the order of 50 years. Therefore all factors contributing to maintaining satisfactory condition are essential to achieve this goal.

Specific Disconnector and Bus performance measures (and condition monitoring) include assessing Buses using annual thermographic surveys to identify high resistance connections. A suitable and targeted condition monitoring program has been developed to establish wall bushing condition using Dielectric Dissipation Factor testing. Dielectric Dissipation Factor testing will be used to justify condition-based replacement. In addition, the PD Hawk and TEV test equipment is utilised to assess insulation condition issues.

Failure Prevention – avoiding catastrophic (unplanned outage more than 24 hours) disconnector/bus failures from occurring within zone substations – target **zero** pa.

Buses and connected switchgear exhibit a wear-out characteristic: They operate for many years without significant numbers of failures, and then age-related or wear-out failures that are not maintenance-preventable begin to occur.

For zone substation buses and connected switchgear, the useful life age has been assessed as 50 years.

Aside from equipment being used within specified ratings the following affects life expectancy:

- Disconnectors, Isolators and Earth switches are affected by the frequency of operation and the type and interval of maintenance. Corrosion and arcing shortens life;
- Connectors are directly affected by high resistance connections. Eliminating corrosion on connectors exposed to the elements and ensuring tight connections maintains life expectancy;
- Flexible connections are prone to becoming loose and creating high resistance joints. Furthermore, the flexible connections on earth switches may become frayed and need replacement;
- Surge arresters are subject to moisture ingress over time;
- Wall bushings must be monitored for surface contamination, which ultimately leads to tracking. Furthermore, oil levels must be monitored to ensure dielectric strength is maintained; and
- Insulators must be monitored for surface contamination which ultimately leads to tracking. Furthermore, pin type insulators have a history of mechanical failure due to corroded metal pins which cracks the porcelain insulator.

A number of factors are assessed to determine if individual assets of the disconnector and bus systems have a high probability that the unit will continue to perform its required function reliably. Aspects such as age, condition, utilisation, effectiveness of risk controls and actual performance are analysed and examined. Outputs from the CBRM model are used to provide a comprehensive assessment of disconnectors/buses condition.

CBRM outputs in the form of Health Indices shown in Section 4.3.3.2 above provide a visual demonstration the condition of the population now and into the future if no corrective measures are taken.

The following sections provide greater detail.

1.9.3.1 *Condition Assessment*

Asset performance for disconnectors/bus systems and circuit breakers is assessed through a holistic asset management approach that includes routine maintenance, testing, diagnostic condition assessments and CBRM. This work is carried out in line with the various associated plans, policies, strategies and standards.

Asset performance measures for JEN zone substation disconnectors/bus systems are designed to achieve a high level of reliability by undertaking a practical, efficient cost program of preventive & corrective maintenance, coupled with planned, economic replacement of assets before failure; to maintain reliability and quality of supply and mitigate the safety risk to personnel and the public.

Specific disconnectors/bus systems performance measures (and condition monitoring) include the following:

- Condition monitoring tests: insulation resistance, partial discharge, dielectric dissipation factor;
- On-line, non-disruptive monitoring surveys: infrared for detecting overheating and ultrasonic detection for air borne partial discharge signals; and
- CBRM output in the form of Health Indices for present and prediction into the future without proactive intervention.

This section provides information about Disconnectors and Buses, as well as general information about other potential issues.

[redacted]

- The “duo-roll” type 66kV disconnector has a history of high contact resistance and corrosion between the clevis & the blade (aluminium tube) and between the blade and beaver tail moving contact. These types of problems lead to overheating and eventually failure if left unattended. Annual thermal scans are used to identify high resistance connections which are then programmed for replacement accordingly.
- The two sets of 22kV isolators on BD7 cable & bus side have been replaced with new AK Power 1250A isolators. Some Taplin isolators fitted to buses and feeders at BD and AW could not be opened as the contacts had welded closed. In some circumstances, the damaged contacts develop a high resistance connection, which causes the load current to flow through the latch mechanism. This results in melting of the latch lever. Defective isolators have been replaced (with AK Power units).
- 7 off 66kV AK Power disconnect switches and 4 off AK Power earthing switches at zone substation SHM (Sydenham) required retrofitting after being CRO’d due to stiffness that affected normal operation. AK Power retrofitted new pivot bearings in the centre rotating insulator stack to ensure free operation. The project was successfully completed in September 2013.
- Earth braids on ganged isolators and earth switches can sometimes be damaged if they get caught in the operating mechanism. These earth braids are replaced if there is significant damage where the current rating is affected.

- Ageing brown porcelain type 66kV and 22kV surge diverters will be co-ordinated for replacement during major construction work within a zone substation, or otherwise programmed as a separate job. Surge Diverters have a limited life and are subject to moisture ingress over time that may lead to ultimate failure. Failure of a porcelain surge diverter may create a safety concern and risk of damage to adjacent plant. Modern surge diverters are manufactured with external silicon polymer housings similar to that of new 66kV transformer bushings, which improves safety when compared to porcelain type housings. It is recommended that a replacement program is prepared to address these issues.

- Brown pin and cap insulators in the 66kV yard at Footscray East (FE) and possibly Heidelberg (HB) have tracking issues and burnt glazing. The insulators at ES, HB, FE and FW have been programmed to be replaced as part of major projects at the respective zone substations. The replacement of the brown pin and cap insulators at ES is outstanding and needs to be prepared as a project. The HB transformer replacement program includes the replacement of all pin and cap insulators and is in progress. Replacement of brown pin and cap insulators at FE has been completed, whereas at FW a switchgear replacement project will commence soon. All pin and cap insulators regardless of the operating voltage or porcelain colour have a known failure mode and should be replaced.

- On 1st February 2020, the No.1 66kV bus, TTS Feeder and No.1 transformer tripped on X and Y protection. Upon inspection the 1-3 66kV bus tie CB No.1 bus side white phase isolator failed. The white phase insulator at the pivot end of the underslung isolator was found shattered, and the isolator blade which forms part of the insulator remained attached to the CB dropper just above ground level. Refer to cracked insulator shed and damaged porcelain insulator due to fault current, below. An incident investigation report was prepared.

- All outdoor 66kV and 22kV pin and cap type insulators at various zone substations should be replaced. This type of insulator, regardless of the porcelain colour, has a history of failures. The sites requiring pin and cap insulator replacements include but not limited to AW, BD, CN, EP, ES, FW, HB, and PV. AW, BD, CN and ES, including various capacitor bank, buses and transformer neutrals etc, require a replacement project to be prepared. Pin and cap insulator replacements at EP, FW and HB will be part of major upgrade projects but must be included in the Scope of Work. When replacing pin and cap insulators, the associated isolator/disconnect blades and earth switches will also be replaced.

- Although only two ABB 22kV isolators with cracked porcelain have been found at zone substations BD and CN, there have been several failures in the distribution network. In each case throughout the JEN distribution network, the porcelain insulator has broken and was either found to be hanging from the HV conductor tail, or in some circumstances has resulted in the isolator blade collapsing during field switching. In addition to this recognised failure mode associated with the porcelain insulator, all ABB isolators installed within zone substations have an inferior latching mechanism which has a history of failure and in need of replacement. The failure of the latch to keep the isolator closed could allow it to open during heavy loads or while carrying fault currents. If the isolator opened under load conditions, customers would have a single phase HV supply or half volts on 240V supply. If the isolator opened while carrying fault currents there will be a flash over and possibly exploding porcelain insulators. Thirty four ABB (24kV, 800A Type 7502501) isolators that were defective in zone substations AW, BD, CN and YTS have now been replaced.
- In 2011 a pin and cap insulator failed in a Victorian electricity network. The failure caused the insulator to separate from its support structure, resulting in the transfer bus isolator together with the pin of the insulator and the tubular bus to be left unsupported. As a result, the tubular bus has bent due to cantilever forces, leaving the pin, isolator and tube hovering approximately 1 metre from the ground. It remained live and was discovered by personnel carrying out ground maintenance. The hovering isolator is identified by the red arrow in Figure 4–17.

Figure 4–17: Failed Pin and Cap Insulator

Porcelain has very high compressive strength (80,000 psi), sixteen times greater than its tensile strength (5,000psi). Pin and cap insulators have a generic design deficiencies when subjected to tensile forces which can lead to the porcelain cracking and eventual failure of the cement joint due to moisture ingress and increased pressure due to corrosion and thermal expansion.

Station post insulators are designed to take advantage of porcelain's compressive strength by avoiding conditions that put them in tension. Each station post section employs a large, single piece of porcelain in contrast to the pin and cap that is composed of one to three individual porcelain shells nested together and joined by cement. The simpler design and the use of fewer cemented joints means that station posts are more rigid and exhibit less deflection under load than pin and cap insulators, which is an important feature in switch applications.

All pin and cap insulators are in need of replacement, will be replaced with station post type insulators, with new isolators, disconnectors, earth switches, upgraded earth receptacle (for portable earths if necessary. But earth switches are recommended in lieu of earth receptacles) and possible new structurers/foundations.

The performance of the 22kV and/or 66kV Buses at AW, BD, CN, ES, FW, and PV is monitored and assessed via field surveys and condition monitoring. The 22kV switchyard at SBY has now been replaced with indoor metal clad switchgear. CN will be replaced as part of CN substation redevelopment. FW will be replaced as part of the switchboard replacement project, which will encompass the new modular building design. The risk of failure of the 22kV buses is managed by conducting thermal and corona surveys and PD condition monitoring using the PD Hawk. This is not a fail safe solution and does not guarantee a failure will not occur.

Furthermore, at BD, the protective screens on some feeder cable terminations are rusty. New screens are recommended to be fitted and designed to comply to Australian Standards such as AS2067.

- Some outdoor structures are exhibiting age related condition issues due the surface coatings (predominately hot galvanising) deteriorating and consequently significant rust has formed on structural members. It is recommended to assess all metallic structures (particularly outdoors) for rust treatment or replacement. Some of the rusty structurers may not visible from ground level.

1.9.3.2 *CBRM Health and Risk Analysis*

Initial CBRM results indicated that the current (Year 0) health index is as shown in Figure 4–18. A total of 296 assets have been identified to be in poor condition with a higher probability of failure. These assets are located at the following locations.

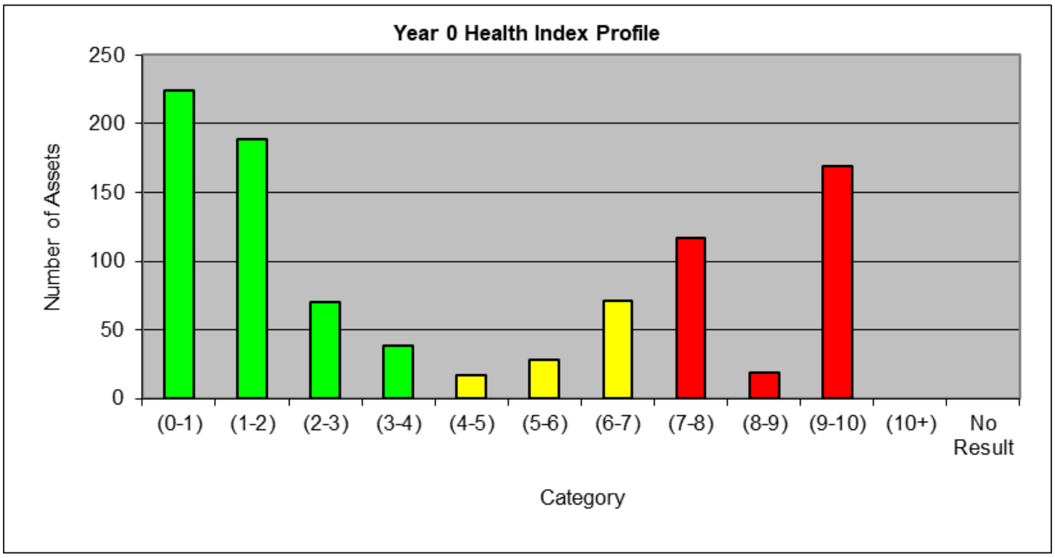
Table 4-40: CBRM (HI>7) Output for Disconnectors and Buses – Year 0 as at 2024

ZSS	Voltage (kV)	Qty.	Item	HI range	Comment
AW	22	45	Disconnectors/Isolators	7.15 – 9.45	Switchyards buses, disconnectors & CBs planned replacement
AW	22	5	Bus	9.10	Switchyards buses, disconnectors & CBs planned replacement
AW	66	3	Bus	7.70	Switchyards buses, disconnectors & CBs planned replacement
AW	66	11	Disconnectors/Isolators /Earth Switches	7.70	Switchyards buses, disconnectors & CBs planned replacement
BD	22	48	Disconnectors/Isolators	7.15 – 9.80	Switchyards buses, disconnectors & CBs planned replacement
BD	22	5	Bus	9.10	Switchyards buses, disconnectors & CBs planned replacement
BD	66		Bus	7.7	Switchyards buses, disconnectors & CBs planned replacement
BD	66	4	Disconnectors/Isolators /Earth Switches	7.70	Switchyards buses, disconnectors & CBs planned replacement
BLTS (MB feeders)	22	2	Disconnectors/Isolators /Earth Switches	9.10	To be replaced with CB planned replacement

ZSS	Voltage (kV)	Qty.	Item	HI range	Comment
BY	22	5	Disconnectors/Isolators /Earth Switches	7.15 - 9.10	To be assessed
CN	22	41	Disconnectors/Isolators /Earth Switches	7.15 – 9.45	Switchyards buses, disconnectors & CBs planned replacement
CN	22	4	Bus	9.10	Switchyards buses, disconnectors & CBs planned replacement
CN	66	3		7.70	Switchyards buses, disconnectors & CBs planned replacement
CN	66	12	Disconnectors/Isolators /Earth Switches	7.70	Switchyards buses, disconnectors & CBs planned replacement
EP	6.6		Disconnectors/Isolators	9.10	Planned replacement by EPN
EP	66	3	Bus	7.70	Planned replacement by EPN
EP	66	15	Disconnectors/Isolators /Earth Switches	7.70	Planned replacement by EPN
ES	66	2	Bus	7.70	Planned replacement
ES	66	2	Disconnectors/Isolators /Earth Switches	7.70	To be replaced
FT	11	2	Disconnectors/Isolators /Earth Switches	7.70	Further assessment
FT	66	14	Disconnectors/Isolators /Earth Switches	7.0	Further assessment
FW	22	25	Isolators & earth switches	8.05 - 9.45	To be replaced with switchgear replacement project
FW	22	2	Bus	9.10	To be replaced with switchgear replacement project
FW	66	3	Bus	7.70	To be replaced with switchgear replacement project
FW	66	14	Disconnectors/Isolators /Earth Switches	7.70	To be replaced with switchgear replacement project
HB	66	2	Bus	7.98	Replacement in progress
HB	66	7	Disconnectors/Isolators /Earth Switches	8.75	Replacement in progress
NH	11	2	Disconnectors/Isolators /Earth Switches	8.05	Further Assessment
NT	66	2	Disconnectors/Isolators /Earth Switches	7.70	Further Assessment
NT	22	4	Disconnectors/Isolators /Earth Switches	7.70 – 8.05	Further Assessment
PV	66	1	Bus	7.70	Further Assessment
PV	66	4	Disconnectors/Isolators /Earth Switches	7.70 – 8.05	Further Assessment

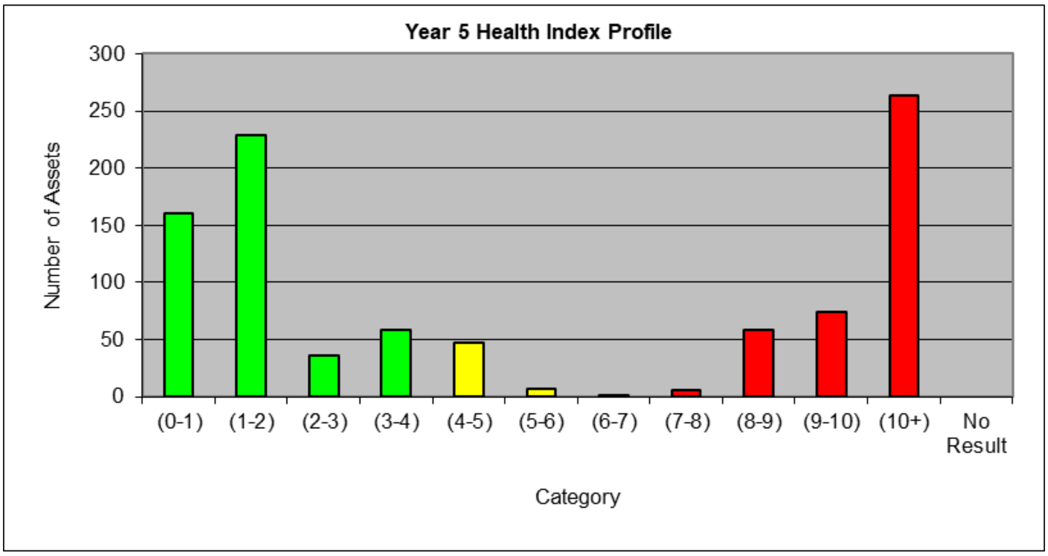
ZSS	Voltage (kV)	Qty.	Item	HI range	Comment
ST	22	2	Disconnectors/Isolators /Earth Switches	7.70	Further Assessment

Figure 4–18: Year 0 Health Indices (as at 2024)



If asset replacement is deferred until 2029 (Year 5), the health index changes as shown in Figure 4–19. A total of 403 assets will be in poor condition with the associated higher probability of failure.

Figure 4–19: Year 5 Health Indices (as at 2024)



If asset replacement is deferred until 2034 (Year 10) the health index changes as shown in Figure 4–20. A total of 405 assets will be in poor condition with the associated higher probability of failure.

Figure 4–20: Year 10 Health Indices (as at 2024)

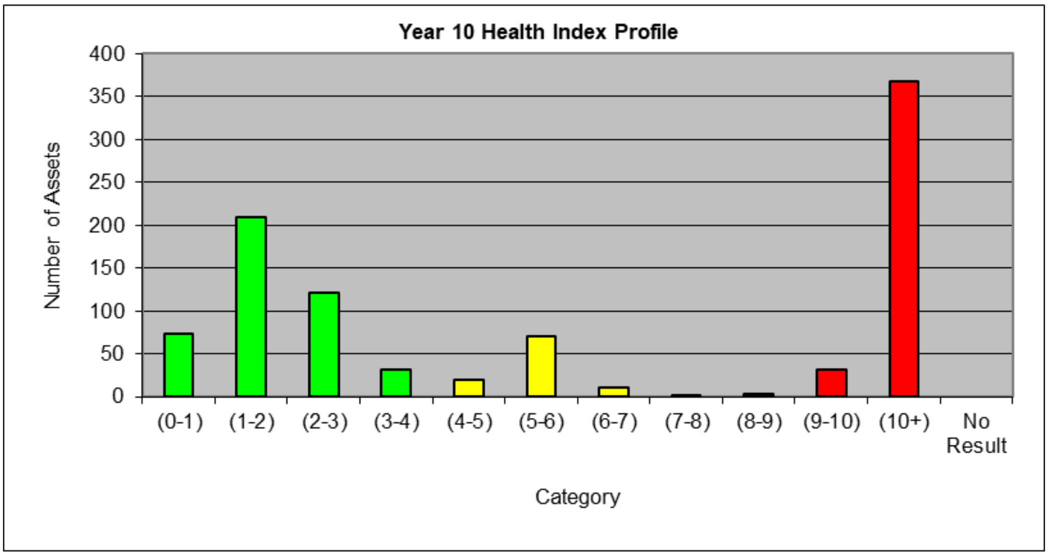


Figure 4–21: Year 15 Health Indices (as at 2024)

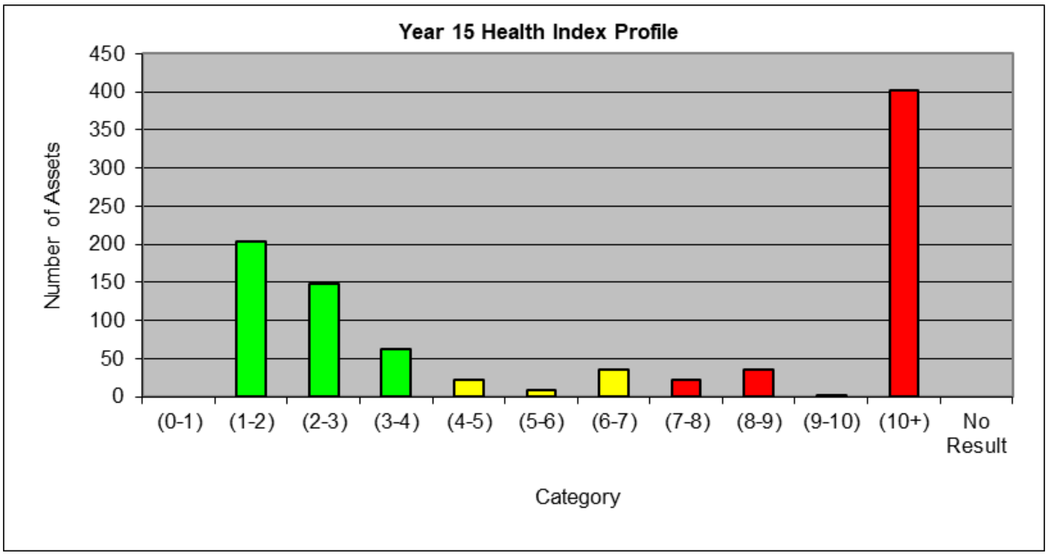
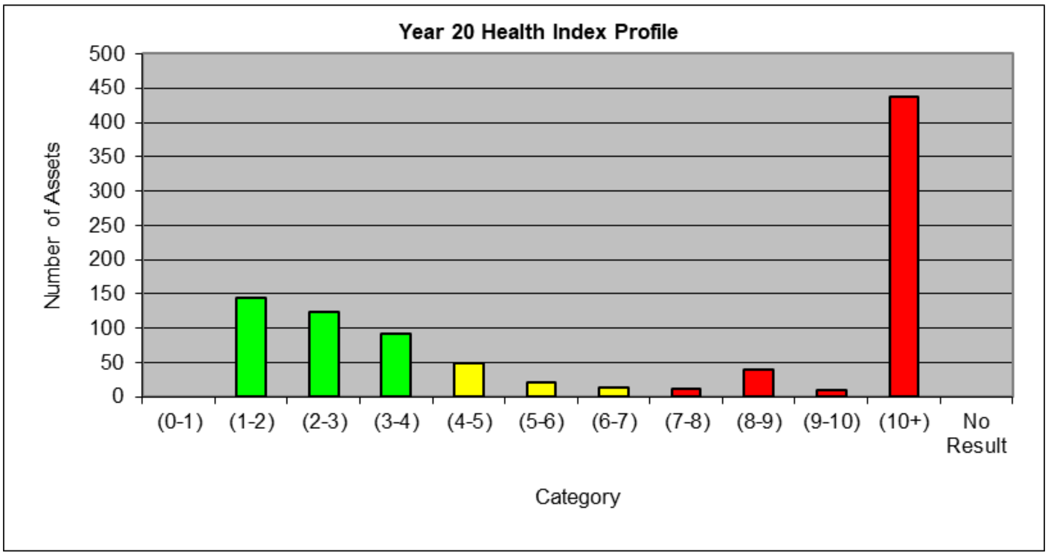


Figure 4–22: Year 20 Health Indices (as at 2024)



If asset replacement is deferred until 2039 (Year 15) the health index changes as shown in Figure 4–21.

If asset replacement is deferred until 2044 (Year 20) the health index changes as shown in Figure 4–22.

These results indicate that the replacement of these assets in the coming years should be undertaken in order to manage the risks associated with the number of assets in poor condition on the network.

Further scenario analysis will be undertaken to determine optimal replacement schedules however the assets identified at AW, BD, CN, BLT(MB feeders), EP, FW and HB as being in poor condition at Year 0 will take priority.

The JEN objective is to maximise asset life and minimise unplanned outages. To satisfy this objective, this strategy has been developed and consists of preventive maintenance, inspections, and planned asset replacement based on rating, condition, and fault history.

Control Effectiveness Controls employed are identified in Section 4.3.4 and condition based replacements completed are listed in Section 4.3.5.8. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following Table 4-41.

1.9.3.3 *Further Information on CBRM*

For further information on CBRM please refer to ELE GU 0005 Condition Based Risk Management (CBRM) Application Guide. The guide provides a summary of how JEN utilises CBRM to justify future replacement volumes for distribution and zone substation assets. It outlies the different inputs required and their associated outputs and how these outputs are interpreted. The CBRM model was initially prepared in 2014.

1.9.4 CONTROL EFFECTIVENESS

Controls employed are identified in Section 1.9.5.3 and 1.9.5.6, and condition based replacements completed are listed in Section 1.9.5.8. These have been employed to manage the identified risks.

The following table assesses the effectiveness of the existing controls by comparing identified risks and measuring past incidents.

Table 4-41: Controls effectiveness

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Disconnector or bus failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed and further identified	One
Regulatory & compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

1.9.5 LIFE CYCLE MANAGEMENT

This Section includes information about Disconnector and Bus asset management practices, including key Disconnector and Bus strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset utilisation;
- asset lifecycle management options;
- asset creation (including asset acquisition and asset spares);
- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- asset replacement and disposal; and
- future improvements.

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure.

1.9.5.1 *Lifecycle management options*

There are four lifecycle management options:

a) Option 1: Corrective maintenance only – fix defects and failures only after they occur.

If Option 1 is implemented, an unacceptable number of customer outages may occur due to equipment failures as per section 1.9.2.3. With a known history of high resistance connections on certain types of disconnectors, failures will inevitably occur at some stage and interrupt supply, affecting customer reliability. Additionally, there will be occasions when all spares will be consumed resulting in long delays to restore the network to system normal.

b) Option 2: Preventive maintenance – a combination of routine maintenance and condition monitoring via thermal surveys and inspection.

Option 2 is the preferred option as it addresses the dominant failure modes. The dominant failure mode that would affect supply reliability is directly related to the condition of the insulating medium. A flashover is likely to occur due to the failure of the asset to provide the required insulation.

A further dominant failure mode describes the ability of a disconnector, or isolator, or connection to carry load. The dominant cause for this condition is a high resistance connection and an appropriate efficient cost control to mitigate the risk is to use infra-red thermal survey as a condition monitoring tool to detect elevated temperatures and undertake repairs before failure (refer JEN 4365-001 Thermal Survey Policy). This condition monitoring technique and subsequent repair on detection of failure has proven successful and is applied to all indoor and outdoor buses.

c) Option 3: Condition based replacement of selected units based on required ratings, condition and/or availability of spare parts for repairs.

As part of the load growth capital planning process, under-rated disconnectors can be identified and economically justified for each project. This option is not acceptable because only under-rated or defective units are replaced and it does not take into account units that present with a deteriorated condition and high risk of failure.

d) Option 4: Replacement of all units based on age (older than 55 years)

Option 4 is not a cost-effective solution as some units will be replaced prematurely whilst still in a serviceable condition and their rating is adequate for their application.

1.9.5.2 *Creation*

Working assets are effectively created via acquisition, upgrades or replacement or the deployment of spares when available.

Four scenarios trigger the need to acquire and connect new Disconnectors and Buses:

- As part of a new zone substation development;
- As a part of an existing zone substation capacity upgrade;
- To replace old assets that have reached end-of-life; and
- Manufacturing or design defect(s).

1.9.5.3 *Asset Operation and Maintenance*

This section provides information about the current asset maintenance program for Disconnectors and Buses.

The current asset maintenance program involves

- Inspection;
- Reactive and corrective maintenance;
- Preventive maintenance; and
- Condition-based monitoring

1.9.5.4 *Inspection*

Zone substations are inspected monthly by operating personnel and annual engineering audits are conducted by the Primary Plant team. In addition, further inspections take place during condition assessment and maintenance.

The following equipment is assessed:

- Buses are assessed using annual thermal surveys to identify high resistance connections. This provides an opportunity to visually inspect the asset in person.

  Because indoor buses do not get washed naturally by rain, maintenance of all indoor 66kV buses and associated switchgear has been implemented. Indoor air insulated type 66kV buses are maintained at the same time as disconnectors.

  Outdoor buses are inspected and insulators cleaned. Maintenance work involves close inspection, checking of connections, and cleaning of insulators, earth switches, surge diverters and wall bushings.

- Disconnectors, isolators and earth switches are mechanical devices and need to be assessed on case-by-case basis taking into consideration the amount of deterioration, age and if the equipment has been fitted with a CRO (caution regarding operation). All disconnectors, isolators and earth switches must operate freely and have clear readable operating identification (signage). The maintenance of disconnectors includes disassembly, cleaning, lubricating, adjusting and functional testing.
- 22kV feeder surge arresters are a run to failure plant item, however if surge arresters are identified as end of life due to age, tracking etc. they will be replaced as part of maintenance works or an applicable project. 66kV surge arresters are tested by measuring insulation resistance. All brown type surge diverters should be assessed for condition and considered for replacement.
- The surface condition of wall bushings (i.e., the presence of cracks and/or tracking), and oil levels are currently assessed during annual engineering audits using binoculars. Furthermore, wall bushings are DDF tested every five years, and if necessary, replacement strategies are implemented.

1.9.5.5 *Reactive and corrective maintenance*

Reactive and corrective maintenance is performed to repair defects identified during in-service inspection (i.e. monthly operator inspections or annual engineering audits), routine maintenance or by thermal surveys. The typical corrective maintenance includes checking connections and cleaning of insulators, earth switches, surge diverters and wall bushings. Maintenance of disconnectors includes disassembly, cleaning, lubricating, adjusting and functional testing.

Regular monthly operator inspections to identify defects and annual thermal surveys to detect high resistance connections of all plant and equipment has been scheduled. Any abnormalities identified either during inspection audits or during switching should be reported to assess asset performance and adjust maintenance intervals.

Preventive Maintenance

The preventive maintenance program for Disconnectors and Buses shall consist of:

- Indoor 66kV buses and associated plant shall be fully maintained on a 6 year cycle;
- 66kV wall and floor bushings shall be maintained with the 66kV indoor buses on a 6 year cycle;
- Outdoor 66kV disconnects, isolators and earth switches will be fully maintained on a 6 year cycle;

- Outdoor 22kV disconnect switches used to interrupt load to de-energise plant will be fully maintained on a 6 year cycle;
- All 22kV HV earth switches will be fully maintained on a 6 year cycle; and
- Motor Operated Disconnectors (with automation isolation requirements) will be functionally operated and checked every 12 months.

Routine full preventive maintenance shall include cleaning, checking of contacts, spring tension and resistance measurement, lubrication & functional tests and is to be performed as part of an outage of the associated major plant items (e.g. bus, line, feeder, transformer).

1.9.5.6 *Condition-Based Monitoring*

Condition-based monitoring programs involve Infra-red thermal imaging. Bus thermal imaging is carried out as part of the general program for monitoring zone substations. It is intended to identify any external problems associated with poor connections or auxiliary equipment operating with abnormal temperature rises.

DDF testing is used to indicate the presence of moisture in the bushing. Moisture penetration of bushings can lead to electrical discharge and failure. The internal failure often results in explosion. Experience with transformer bushings indicates that the probability of moisture ingress increases with age and consequently it is important that the moisture content of the bushings is verified by DDF measurement. Typically, the failure of a wall bushing introduces a hazard to people in the surrounding area. The JEN network does not have a history of wall bushing failures, but with an aging fleet of wall bushings, it is seen as a proactive measure. In 2010 the primary plant group implemented DFF testing on all wall bushings across the JEN network that are greater than 30 years of age. However, access to wall bushing due to issues with working at height has slowed the testing program.

1.9.5.7 *Future Improvements*

A wall and floor bushing DDF testing program is currently in progress. The program and its associated results are continually monitored and evaluated. The following future improvements are currently being considered:

- Purchasing a partial discharge set to perform off line bushing tests; This has been purchased and working well.
- Utilise the PD Hawk to perform RF tests within zone substation switchyards to detect and locate internal and surface PD activity; and
- Maintenance in the form of insulator washing, which includes a close live line inspection of the insulator, is an effective means to mitigate the risk of insulator failure. Future requirement to wash insulators can be evaluated on a case by case basis.

It is recommended that the RCM analysis conducted in 2000 be reassessed to follow the IEC 60300 0-3-11,12, and 14 RCM guidelines and that the maintenance intervals for all sub-asset classes be quantitatively determined.

The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information. The committee members work to share and improve maintenance and replacement knowledge and promote the efficiency and reliability of substation management.

1.9.5.8 *Asset Replacement/Disposal*

Although some disconnectors, isolators and buses have continued to operate satisfactorily for over 50 years, a 50-year-old disconnector, isolator or bus is approaching the end of its practical life. It is paramount to have replacement plans to avoid equipment failure and also avoid large volumes of equipment replacement in short time periods. Ultimately, replacement plans maintain network reliability by preventing failures and therefore also maintain personnel safety within zone substations

As explained in this strategy, a number of projects have been identified to ensure that network performance is maintained and that JEN's compliance requirements are addressed.

Table 4-42 lists the forecast capital expenditure replacement volumes for zone substation disconnectors, buses and earth switches from 2024 to 2030, based on these drivers.

Table 4-42: Forecast Replacement Volumes – Zone Substation Disconnectors

Replacement Volumes – Zone Substation Disconnectors and Buses	Voltage and Year						
	2024	2025	2026	2027	2028	2029	2030
22kV & 66kV pin/cap insulator & isolator replacement at AW	All						
22kV & 66kVpin/cap insulator & isolator replacement at BD	66kV		22kV				
22kV pin/cap insulator & isolator & SD replacement at BLT (BLTS)	All	All					
22kV (Retirement) & 66kV pin/cap insulator & isolator replacement at CN	66kV	22kV					
66kV pin/cap insulator and isolator retirement at EP	All	All					
66kV pin/cap insulator and isolator replacement at ES	All						
22kV (Retirement) & 66kV pin/cap insulator & isolator replacement at FW	All						
66kV pin/cap insulator and isolator replacement at PV	All						

Typically when disconnectors, isolators, earth switches and bus conductors are retired or replaced, any useful spares are retained and the remainder are sent to scrap metal. Surge arrestors and insulators have no retainable spares and are not suitable as scrap metal and are disposed of accordingly. When 66kV oil filled wall bushings are disposed, they are drained of oil, tested for PCBs, and placed in the porcelain bin at Tullamarine depot.

Before any equipment is disposed of it must be assessed by the Asset Engineering group for retainable spares. If other similar plants are contained on the JEN network, all applicable parts will be tested and retained as spares

1.9.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information requirement to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determines the information required to manage and operate an Asset Class.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives. *The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant.

The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-44 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class. Table 4-45 provides the information initiatives required to provide the future information requirements. Included within this table is the risk to the Sub-Asset Class from not completing the initiative.

All of the information required by the Disconnectors and Buses Sub-Asset Class is available within JEN's current business systems.

Table 4-43: Disconnectors and Buses Business Objectives and Information Requirements

Business Objective	JEN Information Sources	Externally Sourced Data
Maintain safety, availability and reliability of Disconnector and Buses	SAP ERP (enterprise resource planning) DrawBridge (drawing management) Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee*. Alerts – from DB's and Government Organisations and manufacturers Manufacturing manuals AS/IEC standards

*The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-44: Disconnectors and Buses Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Disconnectors And Buses – Asset Creation	• Specifications and tender responses • Zone Substation Primary Design Standard • New asset project progress reporting. Completion recorded in SAP • Asset register in SAP		• High – Regulated to maintain supply reliability, safety and quality of supply. Also, a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of Disconnectors and Buses via inspections and audits	Asset register SAP, with details of each asset and significant components; • Manufacturer • Type • Equipment description • Construction year • Basic specification - Voltage - Current • Location: Zone substation name • Address • Condition Monitoring	• Migrate Condition & Performance reports/data into SAP to improve analysis and decision-making. • Photograph Disconnect nameplate and attach to SAP equipment • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	- Maintenance reports - Test reports • Performance history - Daily situation reports - Investigation reports (ECMS) - Plant defect reports • DrawBridge - Single line diagrams - plant data - OEM manuals - design drawings/layouts • SMI's – (Standard maintenance instruction) • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP		
Maintain functionality of Disconnectors and Buses via Preventive Maintenance	• Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. • Scheduled task description, timing and completion recorded in SAP; SMIs held in SharePoint, Policies & Forms • Manufacturers maintenance manuals • SAP notifications and work orders activities performed and components replaced • Details of work completed recorded in SAP • Details of spare equipment located in SAP • OPEX & CAPEX cost reporting recorded in SAP	• Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply
Maintain functionality of Disconnectors and Buses via Condition Monitoring	• Condition monitoring tasks, schedule in SAP and results stored in proprietary test equipment database in SAP • Scheduled task description, timing and completion recorded in SAP.	• Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	• High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	• Outputs from condition monitoring analysis.		
Respond to Disconnector and Bus defects / faults to restore equipment operationally. Perform corrective maintenance.	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components; • Manufacturer • Type • Equipment description • Construction year • Basic specification - Voltage - Current • Location: Zone substation name • Address • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP • Condition Monitoring - Maintenance reports - Test reports • Performance history: - Daily situation reports - Investigation reports (ECMS) - Plant defect reports • DrawBridge - Single line diagrams - plant data - OEM manuals - design drawings/layouts • Asset failure details and investigation reports. • Details of spare equipment located in SAP • OPEX & CAPEX cost reporting recorded in SAP	• Although hard copies of manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in Drawbridge. Manufactures manuals for older assets may not be available. • Access all information via electronic tablet in the field. • All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner. • Update asset data in SAP for missing or incorrect data.	• High: Regulated to maintain supply reliability, safety and quality of supply
Disconnectors and Buses – CBRM	• CBRM analysis Health Index • Held by Primary Plant	• The CBRM model was initially prepared in 2014.	• High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Disconnectors and Buses – Rating suitable for load demand	• ZSS load forecast in ECMS • Published Distribution Annual Planning Report available on JEN's website	• Determine transformer loading guideline	• High: Regulated to maintain supply reliability, safety and quality of supply
ACS Review	• Condition data • Fault/failure data • Maintenance & replacement costs • AMS		• Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-45: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph disconnector nameplate and attach to SAP equipment Access all information via electronic tablet in the field Update asset data in SAP for missing or incorrect data	To improve analysis and decision making Asset data available from business systems saving on site trips To utilise full emergency rating of a transformer during system abnormal operating conditions	Poor efficiency in accessing asset data and delayed response when transformer full ratings are required	Transformer emergency rating and recommendation guideline will ensure accurate assessment and improved understanding in Asset management Asset Data as per RCM and SAP requirements

1.10 ZONE SUBSTATION INSTRUMENT TRANSFORMERS

1.10.1 INTRODUCTION

The Instrument Transformer ACS applies to Instrument Transformers installed on the 66kV and 22kV JEN networks. The 11kV, 6.6kV, and most 22kV networks use metal-clad switchgear.

This strategy applies to stand-alone instrument transformers and does not apply to instrument transformers fitted within metal clad switchgear, power transformers or capacitor banks as they will normally be maintained and replaced together with the major asset.

The Zone Substation Instrument Transformer Asset Sub-Class Strategy provides an asset overview and identifies the best strategies and plans for managing assets over their lifecycles.

The Asset Sub-Class Strategy is based on key information about each asset (including risk, performance, capital expenditure and operational expenditure). Based on this information, the Asset Sub-Class Strategy provides details about the JEN's zone substation instrument transformer asset class strategies for the next five years and comprises five key areas:

- Asset class profile includes information about the type, specifications, life expectancy and age profile of zone substation instrument transformers in service across the JEN.
- Asset strategy outlines zone substation instrument transformer asset management practices. This includes key zone substation instrument transformer strategies and plans that support the corporate business plan, strategies and objectives and inform expenditure plans and programs of work. See Section 4.4.9 Life Cycle Management.
- Asset risk includes information about asset risk, including causes and consequences. See Section 4.4.5 Risk.
- Asset performance provides information about performance objectives, drivers and service levels, and the technical and commercial risks associated with zone substation instrument transformer management. See Section 4.4.6 Performance.
- Asset expenditure assessment provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

This Section includes information about the type and specifications of the instrument transformers in service across the JEN.

Instrument transformers are high accuracy class electrical devices used on the JEN to transform voltage or current levels. The most common usage of instrument transformers is to operate instruments or metering from high voltage or high current circuits, safely isolating secondary control circuitry from the high voltages or currents. The primary winding of the transformer is connected to the high voltage or high current circuit, and the meter or relay is connected to the secondary winding.

1.10.2 VOLTAGE TRANSFORMERS

In each zone substation, the 22kV, 11kV and 6.6kV systems typically have a voltage transformer (**VT**) installed on each bus or on the secondary of each transformer for voltage control, protection and metering.

On the 66kV system, VTs are usually single phase, oil-immersed types fitted with porcelain or polymeric bushings. They may be either magnetic or capacitive coupling types, which are generally hermetically sealed. In some cases, 3 phase 66kV oil filled VTs have been installed for protection and metering.

1.10.3 CURRENT TRANSFORMERS

Current transformers are installed on feeders, buses, and transformer circuits to satisfy the requirements of various protection schemes such as overcurrent, earth protection, and metering. All CT's are single phase and can be grouped as follows:

- Oil immersed type inside bulk oil circuit breakers;
- Oil immersed type post CTs
- Dry synthetic epoxy resin types supplied together with vacuum or SF6 dead tank circuit breakers;
- Oil immersed types inside power transformers; and
- Dry synthetic epoxy resin types supplied together with metal clad switchboards.

1.10.4 ASSET SPECIFICATION

Table 4-46 identifies the number, type and construction year of instrument transformers installed across Zone Substations on the JEN network. Not all zone substations contain post type instrument transformers as they are mounted within Dead Tank CBs, metal-clad switchgear and inside transformers.

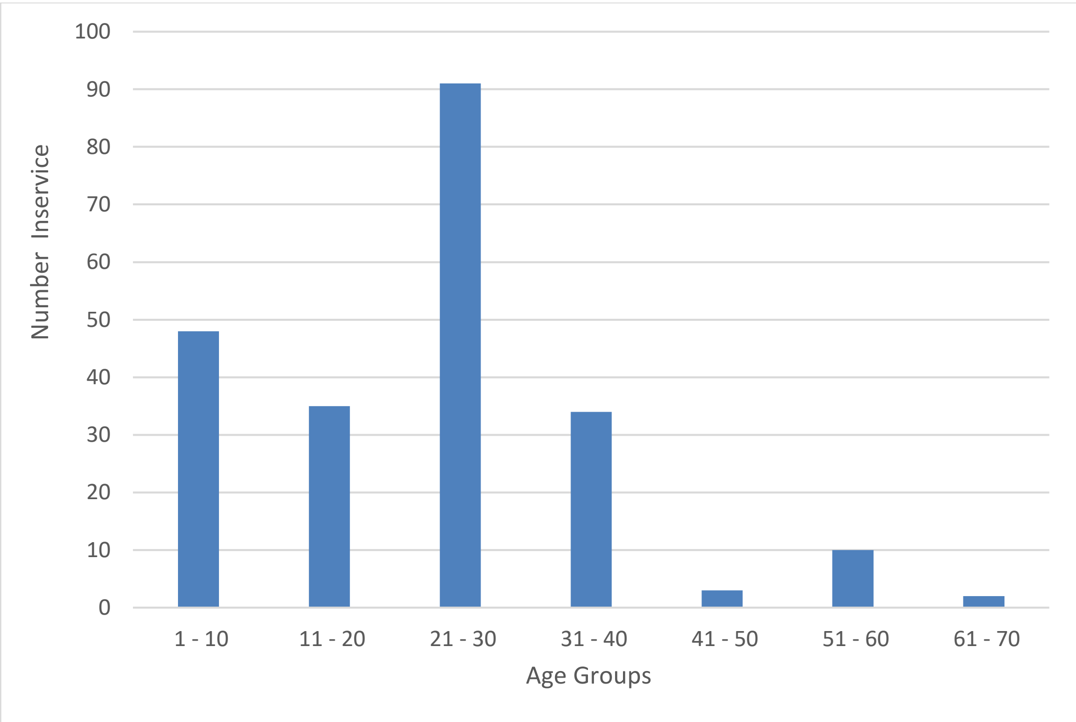
Table 4-46: Instrument Transformer Information (Post Type)

Zone Substation	Installation Year (Range)	Number of Post CTs per Phase	Number of Post VTs per phase
AW (Airport West)	1964 – 2001	9	6 + 2x3ph
BD (Broadmeadows)	1961 – 2002	15	9 + 2x3ph
BLT(BLTS)	N/A	0	0
BMS (Broadmeadows South)	2014	0	0
BY (Braybrook)	1999	6	4
CN (Coburg North)	1967 – 2001	15	3+ 3x3ph
CS (Coburg South)	N/A	0	0
COO (Coolaroo)	2006 – 2007	0	6
EP (East Preston)	2003	3	0
EPN (East Preston)	2015	0	3
ES (Essendon)	2018	0	6
FE (Footscray East)	1999 – 2021	3	6
FF (Fairfield)	N/A	0	0
FT (Flemington)	N/A	0	0
FW (Footscray West)	2008	0	3
HB (Heidelberg)	2010	3	3
MAT (Melbourne Airport)	2002-2019	9	6
NEL (North East Link)	2021	0	6
NEI (Neilson)	1990	6	0
NH (North Heidelberg)	N/A	0	0

Zone Substation	Installation Year (Range)	Number of Post CTs per Phase	Number of Post VTs per phase
NS (North Essendon)	N/A	0	0
NT (Newport)	N/A	0	0
PTN (Preston)	2018	0	6
PV (Pascoe Vale)	2011	0	6
SBY (Sunbury)	1990 - 2018	3	18
SHM (Sydenham)	2007	0	6
SSS (Somerton Switching)	2001	12	8
ST (Somerton)	2001	0	6
TH (Tottenham)	1984	3	0
TMA (Tullamarine)	N/A	0	0
VCO (Visy Coolaroo)	1988	3	6
WGT (West Gate Tunnel)	N/A	0	0
YVE (Yarraville)	2000 – 2013	3	6

The age profile of the 223 Post Type and 3 phase Instrument Transformers installed on the JEN is shown in Figure 4–23. The majority of JEN instrument transformers were installed between 1961 and 2021.

Figure 4–23: Instrument Transformer Age Profile (Dec 2024)



1.10.5 RISK

This section includes information about instrument transformer risk profiles involving the way that asset class criticality is established, the risks posed by instrument transformer failure (including the various failure types and their possible consequences), other measures being introduced to manage asset risk, and a list of the various issues currently confronting instrument transformers.

This information specifically involves:

- Asset class criticality score (sub-asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Existing controls;
- Asset Spares;
- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

Instrument Transformers are generally very reliable and the risk of failure is considered to be low. The major risk associated with instrument transformer operation has been identified as personnel safety in the event of potential failures.

Emerging risks for this asset class include:

- Ageing population;
- Deteriorating interior insulation condition of oil/paper insulation system due to heat and electrical stress by being in-service;
- Deterioration of sealing systems, allowing moisture and oxygen into insulation system;
- Expenditure prioritisation restricting timely replacements; and
- Managing population of CT's with 5 Amp secondaries with emerging new technology to introduce 1 Amp CT secondaries, including spares.

1.10.5.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). The results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is used to rank the importance of dissimilar sub-asset classes (e.g. transformers and buildings and grounds) to identify areas where risk should be managed first and control measures implemented.

The instrument transformer has an asset criticality score of AC2 (Moderate) due to the operational, health, and safety consequences associated with failures.

JEN zone substations supply an average of 13,065 customers and contain an average of 8.4 instrument transformers. Instrument transformers are a low-volume asset with high criticality, which is defined by:

- A severe failure of protection CTs takes the bus protection out of service and severely restricts the operation of the substation. The strategic impact on customer supply may be affected (if N-1 is compromised and transfer capability is limited, load shedding may be required);
- Long lead time for repair or replacement (procurement of a new instrument transformer is typically 4-6 months), unless spares are purchased, then replacement can be undertaken within 24 hours; and

- High consequence of failure (loss of supply and OH&S issues). On specific post type CTs, when the unit fails their porcelain housing shatters. The broken pieces can travel many metres and cause serious damage to adjacent equipment and injury to personnel.

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures. Provided spares are available to replace a failed CT or VT, it is not expected outages will exceed 24 hours.

However, if spare units are not available or an explosive failure damages adjacent assets, strategic failures may occur.

Typical Instrument Transformer faults include:

- Internal insulating column breakdown failure due to oil/paper deterioration, electrical stress or moisture ingress;
- External housing insulation failure (flashover) due to lightning, animals and birds or pollution; and
- Thermal failure due to a deteriorated or high resistance joint or connection.

The consequences resulting from these faults can include:

- Housing failure and associated explosion and flying porcelain and or metal pieces; and
- Oil spillage and possible fire.

Destruction of the complete unit and possibly damage to adjacent assets.

1.10.5.2 *Spares*

As part of the criticality assessment, consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002). It was determined that adequate instrument transformer spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team.

System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub transmission line due to an instrument transformer failure.

Critical Spares Assessment Procedure (ELE-999-PR-RM-002) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I.

Furthermore when assets are retired from service, consideration is given to retaining components or entire asset as spares to service existing aging fleet.

A spare set of 66kV VT's was purchased as part of the 2014 project to replace the defective VT at SBY: Installation of 3 66kV VT's at SBY (BAA-RSA-000029). Currently JEN does have series of spare 66kV VT's and CT's. The current spares policy proposes maintaining a complete fleet of spare 66kV sub-transmission instrument transformers to ensure network reliability is maintained. Spares will be collected from various ZSS augmentation projects.

1.10.5.3 *Failure Modes*

Instrument transformers are critical assets installed to fulfil protection and metering functions associated with the safe and reliable operation of the HV networks. These assets can experience insulation break down and in rare circumstances catastrophic failure can occur.

The dominant CT & VT failure modes that impact on the reliability of the network are as follows:

- failure to insulate (external)due to lightning, over-voltages due to switching, animals and birds or insulation deterioration/contamination or pollution;
- failure to insulate (internal) due to deteriorated paper/plastic insulation material, poor condition insulating oil, PD tracking and breakdown due to moisture ingress or oil/paper system contamination during manufacture;
- failure to carry fault currents;
- failure to carry load due to high resistance connections resulting in thermal overheating; and
- Destruction of complete unit and possibly damage to adjacent assets.

1.10.5.4 *Existing Controls*

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.4.9.3 and 4.4.9.7, together with initiation of replacement projects for assets determined to be in danger of major failure.

1.10.5.4.1 Contingency

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the failed CT or VT. Once determined, either components are replaced or whole unit replaced with a spare from stock. In lieu of replacing defective 66kV post CTs, the live tank circuit breaker can be replaced with a dead tank CB with integral CTs. Spare 66kV and 22kV post CTs are stored at the Tullamarine depot.

1.10.6 PERFORMANCE FACTORS

Current Transformers are expected to withstand their rated normal and fault level current carrying capability and deliver rated secondary current signals. VTs are expected to withstand normal and temporary over-voltages and deliver rated secondary voltage signals, as well as maintaining HV insulation for a life time in the order of 50 years. Therefore all factors contributing to maintaining satisfactory condition are essential to achieve this goal.

Historically Instrument Transformer performance measures (and condition monitoring) has included infra-red thermal imaging to identify hot spots and visual inspections to identify defects. Historically instrument transformers have been reliable items of plant with 3 (CN, ES and SBY) failures in the past 20 years. A suitable and targeted condition monitoring program that includes DLA testing and Partial Discharge testing was implemented in 2014 and 2015 respectively. The DLA and Partial Discharge conditioning monitoring results will be recorded and monitored, so the assets performance can be assessed in the future and prioritised for replacement. Currently, condition monitoring is the primary driver used to determine instrument transformer condition.

1.10.6.1 *Performance requirements/targets:*

Failure Prevention – avoiding catastrophic (unplanned outage of more than 24 hours) instrument transformer failures from occurring within zone substations - target zero per year.

The design life expectancy of an instrument transformer is approximately 50 years. However, when primary plant is replaced usually instrument transformers are upgraded.

1.10.6.2 *Condition Assessment*

This section provides information about Instrument Transformers, as well as general information about other potential issues on the JEN network:

- The replacement of ASEA IMBA oil immersed 66kV post CTs associated with outdoor minimum oil breakers was completed several years ago. This was undertaken due to known incidents of explosive failure. Consequently, all other instrument transformers will be monitored, and replacement plans will be established when the condition indicates end of life is approaching. Condition monitoring tests as per section 4.4.9.7 (Condition Monitoring) are used to monitor and prioritise replacement.

- The Crompton Greaves 66kV VTs installed at CN on the TTS line have been inspected for condensation within the sight glass. The bellows are constructed from stainless steel.

- The polycarbonate sight glass on the Crompton Greaves 66kV VTs installed at AW (KTS line) had deteriorated and was replaced. This revealed that the red phase bellows were 5mm above the minimum oil level and no oil leaks were visible. The white and blue phase VT bellows were approximately 25mm above the minimum level at an ambient temperature of 21 deg C. The manufacturer has advised that the bellows level should be half way between Min and Max at 30 degrees. Crompton Greaves Power has reviewed the information regarding this VT and the adjacent units, and advised that since there is no oil leak, the VT can remain in service. The bellows should be monitored.

- The white phase CVT on the No.6 66kV bus at SBY had a severe oil leak identified during a routine engineering audit. Repairs were attempted on site but were unsuccessful. Later, during a site inspection, it was identified that the leak had developed further. The CVT was subsequently taken out of service for further repairs. After consultation with ABB and Tyree it was found that the CVT had lost two thirds of its oil and could not be repaired. This affected the KTS 66kV line protection and station security as this CVT is used to provide the potential supply to the KTS 66kV line distance protection. These Tyree CVTs are common in JEN zone substations, they are prone to leaking and are not repairable. It is for this reason that the red and blue phase CVTs on the No.6 66kV Bus at SBY were replaced with new VTs, and an additional set was purchased and kept as spares should a similar scenario occur in other zone substations. This is in consideration of the long lead time of 25 weeks to procure new VTs.

- On the 2nd of February 2014 the new ABB type 2GSA MVTs that replaced the existing CVTs on the No.6 66kV at SBY bus failed catastrophically after being in service for approximately 4 months. Investigations have revealed that a further 13 of the same type ABB MVTs are located within the JEN. A detailed Incident Investigation was prepared and action items were completed. This included testing similar units within the network.

- A project had been initiated to purchase and install 3 off 1-phase 22kV CTs at ZSS CN for CN11 feeder CB. The white phase of the existing 22kV CT is leaking oil. A temporary repair was carried out and 11 litres of oil was added in July 2013. The repair resulted in reducing the severity of the oil leak. However, it didn't completely stop it. The CT was being monitored and oil topped up every 2 weeks until it is replaced. Feeder CN11 supplies a Co-Gen customer and a failure of the white phase 22kV CT will result in the disconnection of the Co-Gen customer from the JEN for the duration of the outage. In addition to the disconnection of the Co-Gen customer, JEN customers supplied from feeder CN11 will also be also disconnected. The CTs on feeder CN11 have been replaced.

- The Conelec 66kV CTs have been replaced as part of the 2015 business case to replace the 1-2 66kV Bus-Tie CB at ZSS ES (BAA-RSA-000071). These CTs have condition issues that were identified during the DLA testing program implemented in 2014. The condition issues relate to DLA values that were around the 1% range. There is industry knowledge of explosive failure of CTs with DLA readings >1%. [redacted]

- AusNet at LDL experienced a catastrophic fault within a CVT manufactured by TYREE in January 2023.. The root cause seems to be an internal fault. Ausnet does take oil samples on some types of VTs. However, these units are hermetically sealed, and oil samples, in this case, have not been taken and are not recommended. Ferro-resonance is also being considered. JEN has one set installed at SBY, manufactured by TYREE, type 04/72/2, SECV specification No. 78/251, and YOM 1979. The SBY unit has been tested and disconnected from the bus to eliminate the safety exclusion.
- Older instrument transformers need to be replaced, and the fleet of Plessy Ducon instrument transformers should be considered for future replacement.

1.10.7 UTILISATION

Instrument transformers are permanently connected to the system to provide metering and protection in terms of current and/or voltage. As a result, their utilisation is virtually continuous. Current transformers are operated within their rated normal and fault current carrying ratings. Voltage transformers are operated within their normal and overvoltage ratings.

1.10.8 CONTROL EFFECTIVENESS

Controls employed are identified in Section 1.10.9.3 and condition based replacements completed are listed in Section 1.10.9.8. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following Table 4-47.

Table 4-47: Controls Effectiveness

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Instrument Transformer failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed and further identified	MVT Feb 2014 at SBY One at CN One at ES
Regulatory & compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	As above projects
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

1.10.9 LIFE CYCLE MANAGEMENT

This chapter includes information about instrument transformer asset management practices, including key instrument transformer strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset utilisation;
- asset lifecycle management options;
- asset creation (including asset acquisition and asset spares);

- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- asset disposal; and
- future improvements.

1.10.9.1 *Asset Lifecycle Management Options*

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure.

The preferred asset lifecycle management option involves condition monitoring and preventive maintenance, with the aim of achieving at least 50 years of asset life before replacement.

There are three feasible lifecycle management options:

a) **Condition monitoring, preventive maintenance and condition based replacement**

Condition monitoring is limited to operators and engineers performing monthly and yearly audits, thermal imaging and detailed inspections that are conducted as part of maintenance works associated with applicable plant. The in-service reliability of instrument transformers has been high with 2 failures occurring. These failures occurred at zone substations SBY in 2013 and ES in 2015. A suitable and targeted condition monitoring program has been developed to establish instrument transformer condition, so that condition based replacement can be planned as required. This program has been employed to test VTs and CTs as per section 4.4.9.7. Since modern types of instrument transformer have failed, a rigorous testing program may be necessary. The entire condition based testing program should be reviewed and consideration to test younger instrument transformers is recommended. SAP maintenance plans need to be created or updated once a new testing interval has been established.

Furthermore, all other instrument transformers that have reached a 40 year life need to have maintenance plans scheduled in SAP for condition testing. This needs to be monitored and maintenance plans created.

All new installations will be DLA and PD tested as part of the commissioning program.

b) **Inspection, corrective maintenance and fixed, age-based replacement (irrespective of condition)**

Condition monitoring and maintenance as per Option 1 with replacement at a nominated age of say 40 years, which is the expected useful service life with low probability of failure. This option is not considered to be cost-effective as assets in good condition will be replaced prematurely. Condition monitoring and preventive maintenance can be employed to defer capital replacement, and assets will then be replaced to mitigate safety risks and reduced reliability risks.

c) **Run-to-failure replacement**

Condition monitoring and maintenance as per Option 1 with replacement upon failure. This is not an option due to the criticality of the assets (instrument transformers). Run to failure will impact on health and safety and have a negative impact on supply reliability. Furthermore, the risk to the network due to long lead times when procuring replacement assets can be mitigated by purchasing spares.

1.10.9.2 *Creation*

Working assets are effectively created via acquisition or the deployment of spares.

Three scenarios trigger the need to acquire and connect new Instrument Transformers:

- As part of a new zone substation development;
- As a part of an existing zone substation capacity upgrade; or
- To replace old instrument transformers that have reached end-of-life.

1.10.9.3 *Asset Operation and Maintenance*

The current asset maintenance program involves:

- Inspection;
- Reactive and corrective maintenance;
- Preventive maintenance; and
- Condition-based monitoring.

1.10.9.4 *Inspection*

Condition monitoring is the primary driver used to determine VT and CT conditions. Historically, visual and thermal (infra-red) inspections have been used as analysis tools, however a DLA testing program was implemented in 2014 to determine the condition of instrument transformers further. DLA testing is used to assess insulation condition to detect defects like water trees, electrical trees, moisture and air pockets so instrument transformers can be prioritised for replacement before failure occurs.

Partial discharge is a prominent cause of high voltage system failures. In late 2014 partial discharge testing equipment was purchased, and testing of instrument transformers began in 2015. Partial discharge testing assesses the quality of equipment’s insulation and overall equipment health. Partial discharge testing aims to find the following before failure occurs:

- Corona discharges;
- Surface discharges;
- Discharge in laminated material;
- Cavity discharges; and
- Treeing.

Ultimately, the purpose of introducing Partial Discharge and DLA testing is to:

- Prevent failures;
- Improve safety;
- Decrease costs;
- Reduce capital expenditure and loss of supply; and
- Manage maintenance, refurbishment and replacement.

The condition monitoring and testing of instrument transformers may determine whether the maintenance regime will be modified to address defect issues or the asset may be prioritised for replacement as part of a capital program.

Although there are many instrument transformers on the JEN network, the in-service reliability has been high. Their reliability performance can be maintained with minimal work as described below:

- Operators visually inspect instrument transformers external to major plant items when visiting substations to detect any obvious defects. Checks are to be made for signs of oil leaks, tank distortion, and damage to bushings and leads. Engineers also conduct annual zone substation audits identifying any obvious defects.
- The thermal imaging of instrument transformers is carried out annually as part of the general program for condition monitoring of all zone substations assets. It is intended to identify any external problems associated with poor connections operating with abnormal temperature rises.
- Detailed inspections are conducted as part of maintenance works associated with the applicable plant (circuit breaker, bus or line) as appropriate.

1.10.9.5 *Reactive and corrective maintenance*

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified faults (or both). Oil testing, refilling and repairs of instrument transformers is a specialised field of work that needs to be assessed on a case by case basis.

1.10.9.6 *Preventive maintenance*

Instrument transformers are serviced as part of the maintenance on the associated major plant item. For example, current transformers with their associated circuit breakers and voltage transformers as part of bus maintenance. This maintenance is limited to checking connections, cleaning, and testing insulation resistance.

Oil testing, refilling and repair of instrument transformers is a specialised field of work that needs to be assessed on a case by case basis. Hermetically sealed instrument transformers should not have their seals disturbed unless deemed necessary. Oil sampling and testing of instrument transformers operating at 66kV and below has generally not been implemented by the Electricity Supply Industry, as the risk of contamination and subsequent failure is considered to be high. A diagnostic condition monitoring program will be considered in lieu of oil sampling.

Insulation resistance measurement is to be conducted on instrument transformers to monitor their condition. For sub-transmission oil-filled instrument transformers, once over 40 years old, a comprehensive set of condition monitoring tests (Insulation Resistance, Partial Discharge, Dielectric Dissipation Factor and Capacitance) is to be conducted. These tests are to be conducted at 5 yearly intervals unless results show rapid degradation over time, in which case, are to be conducted at more frequent intervals. It is recommended to reassess the age of the asset and consider a condition monitoring program once the asset reaches 30 years.

A spreadsheet has been prepared to monitor asset age and schedule maintenance after 40 years. The maintenance plan creations is reviewed regularly and the instrument transformer once at 40 years of life will be created. This process must be continued and monitored. All such maintenance plans should be created and scheduled into the future.

1.10.9.7 *Condition-based monitoring*

JEN's condition-based monitoring programs involve:

- Visual inspections performed monthly by operators and yearly by engineers;
- Infra-red thermal imaging;
- Detailed inspections conducted as part of maintenance works on specific plant; and
- DLA and PD testing.

1.10.9.8 *Asset Replacement/Disposal*

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how JEN prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-48 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure.

Table 4-48: Asset Class Specific Drivers: Zone Substation Instrument Transformers

Driver	Risk/Opportunity Description	Consequence
Health, Safety and Environment Asset Integrity	Failure of instrument transformer	Breakdown of insulation leading to fire/ porcelain explosion that will present safety and environmental issues Loss of supply to up to 10,000 customers for over three hours while switching transfer occurs

The volumes of work required and associated capital and operational expenditure ensure that the consequences identified in the table above are addressed to maintain network performance and manage risk. It is a prudent approach, and ensures that the long term interests of customers are maintained.

The following replacements have taken place:

- No.6 66kV bus CVT at SBY;
- No.6 66kV bus ABB MVT at SBY 2014;
- 22kV CN11 CTs 2014; and
- 66kV Conelectric CTs at ES 2015.

Table 4-49: Historical Replacements – Zone Substation Instrument Transformers

Replacement Volumes – Zone Substation Instrument Transformers	Year							
	Unit	2012	2013	2014	2015	2016	2017	2018
Zone substation instrument transformer	ea	-	-	9	3	-	-	-

As identified in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

Table 4-50: Planned Replacements – Zone Substation Instrument Transformers

Volumes – Instrument Transformers		Year						
	Unit	2024	2025	2026	2027	2028	2029	2030
Zone substation instrument transformer	ea	-	-	3	-	-	-	3
Plessey Ducon CT at NEI	ea	3	-	-	-	-	-	-
SBY No.1 66kV bus CVT	ea	-	-	-	-	-	-	-

These will be replaced as a part of the Coburg North (CN) Redevelopment project in 2026 and the North Heidelberg (NH) Redevelopment project in 2030.

Typically when instrument transformers are retired and not required/suitable as spares, they are taken to Tullamarine depot and kept in the bunded area. They are then collected for oil testing and disposing of it accordingly.

1.10.9.9 *Future Improvements*

- Current transformers carrying normal and fault currents and VTs are subject to multiple temporary over voltages. Instrument transformer insulation systems are a small volume within an insulated housing. Therefore, this design inherently has high electrical stresses and requires the insulation to be of high quality without any contamination to achieve a long life. Catastrophic failures have occurred in the wider electricity supply industry. Porcelain was previously specified for all 66kV instrument transformers but has since been revised to polymeric housings to further reduce the consequences of shattering porcelain during a failure.
- The industry has experienced failures of younger types of instrument transformers and as a result a rigorous testing program has become necessary. The entire condition based testing program is to be reviewed and consideration to test younger instrument transformers is recommended. SAP maintenance plans need to be created once a new testing interval has been established.

  It is recommend to reassess the age of the asset and consider a condition monitoring program once the asset reaches 30 years.
- Older instrument transformer need to be considered for replacement.
- The fleet of Plessey Ducon instrument transformers should be considered for future replacement.
- Consider installing VT overvoltage monitoring alarm for immediate emergency switching. Further research into the phenomenon needs to be assessed.
- It is recommend to reassess the RCM analysis conducted back in 2000 to now follow the IEC 60300 0-3-11,12 and 14 RCM guidelines, and quantitatively determine the maintenance intervals for all sub-asset classes.

1.10.10 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information requirement to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determines the information required to manage and operate an Asset Class.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information requirements (Table 4-51). Table 4-52 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class. Table 4-53 provides the information initiatives required to provide the future information requirements identified in Table 4-52. Also included in Table 4-53 is the risk to the Sub-Asset Class from not completing the initiative.

All of the information required by the transformer Sub-Asset Class is available within JEN's current business systems.

Table 4-51: Instrument Transformer Business Objectives and Information Requirements

Business Objective	JEN Information Sources	Externally Sourced Data
Maintain safety, availability and reliability of instrument transformers	SAP ERP (enterprise resource planning) DrawBridge (drawing management) Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee*. Alerts – from DB's and Government Organisations and manufacturers Manufacturing manuals AS/IEC standards

*The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-52: Instrument Transformer Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Instrument Transformer – Asset Creation	• Specifications and tender responses • Zone Substation Primary Design Standard • New asset project progress reporting. Completion recorded in SAP • Asset register in SAP		• High – Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements

Maintain functionality of Instrument Transformers via inspections and audits	Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• Basic specification
	  - Voltage
	  - Current
	• Location: Zone substation name
	• Address
	• Condition Monitoring
	  - Maintenance reports
	  - Test reports
	• Performance history
	  - Daily situation reports
		• Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.
		• Photograph Instrument transformer nameplate and attach to SAP equipment.
		• Access all information via electronic tablet in the field.
		• Update asset data in SAP for missing or incorrect data.
			• High – Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	- Investigation reports (ECMS) - Plant defect reports • DrawBridge - Single line diagrams - plant data - OEM manuals - design drawings/layouts • SMI's – (Standard maintenance instruction) located on JEN's Intranet • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP		
Maintain functionality of Instrument Transformers via Preventive Maintenance	• Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. • Scheduled task description, timing and completion recorded in SAP; SMIs held in SharePoint, Policies & Forms • Manufacturers maintenance manuals • SAP notifications and work orders activities performed and components replaced • Details of work completed recorded in SAP • Details of spare equipment located in SAP • Operating OPEX & CAPEX reporting recorded in SAP	• Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply
Maintain functionality of Instrument Transformers via Condition Monitoring	• Condition monitoring tasks, schedule in SAP and results stored in proprietary test equipment database in SAP • Scheduled task description, timing and completion recorded in SAP. • Outputs from condition monitoring analysis.	• Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	• High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)

Respond to Instrument Transformer defects / faults to restore equipment operationally.
Perform corrective maintenance
	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• Basic specification
	  - Voltage
	  - Current
	• Location: Zone substation name
	• Address
	• SAP notifications and work orders activities performed and components replaced.
	• Details of work completed recorded in SAP
	• Condition Monitoring
	  - Maintenance reports
	  - Test reports
	• Performance history:
	  - Daily situation reports
	  - Investigation reports (ECMS)
	  - Plant defect reports
	• DrawBridge
	  - Single line diagrams
	  - plant data
	  - OEM manuals
	  - design drawings/layouts
	• Asset failure details and investigation reports. Stored in ECMS
	• Details of spare equipment located in SAP
	• OPEX & CAPEX cost reporting recorded in SAP
		• Although hard copies of manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in in Drawbridge. Manufactures manuals for older assets may not be available.
		• Access all information via electronic tablet in the field.
		• All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.
			• High: Regulated to maintain supply reliability, safety and quality of supply

ACS Review	• Condition data • Fault/failure data • Maintenance & replacement costs • AMS		• Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-53: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph instrument transformer nameplate and attach to SAP equipment Access all information via electronic tablet in the field Update asset data in SAP for missing or incorrect data	To improve analysis and decision making Asset data available from business systems saving on site trips	Poor efficiency in accessing asset data	Asset Data as per RCM and SAP requirements

1.11 ZONE SUBSTATION CAPACITOR BANKS

1.11.1 INTRODUCTION

The Zone Substation asset sub-class strategy applies to capacitor banks installed in zone substations and includes the capacitor cans, the inrush current limiting reactors, the current transformers and earth switches within the capacitor bank enclosures

The Zone Substation Capacitor Banks Asset Sub-Class Strategy (**ACS**) provides an asset overview, and identifies the best strategies and plans for managing assets over their lifecycles.

The ACS is based on key information about each asset (including risk, performance, capital expenditure and operational expenditure). Based on this information, the asset class strategy provides details about the JEN Electricity Network's (**JEN**) capacitor banks and comprises five key areas:

- Asset class profile includes information about the type, specifications, life expectancy and age profile of capacitor banks in service across the JEN.
- Asset strategy outlines capacitor banks asset management practices. This includes key capacitor bank strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and programs of work. See Section 7.1.4 Life Cycle Management.
- Asset risk includes information about asset risk, including causes and consequences. See Section 4.5.2 Risk.
- Asset performance provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with capacitor bank management. See Section 4.5.3 Performance.
- Asset expenditure assessment provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

This section includes information about the type and specifications of the capacitor banks in service across JEN.

Installation of capacitor banks in zone substations is found to be a very economical way to increase the utilisation of station assets, defer capital expenditure by optimising the available capacity of the network, and provide voltage support particularly within industrial supply areas and periods of high load demand during summer and winter.

There are 35 Capacitor banks which vary in size from 4MVAR to 12MVAR. A fully loaded zone substation can have a maximum of 36MVAR (3 x 12MVAR) reactive capacity. They are time or VAR controlled, automatically or manually switched. They help reduce:

- avoidable sub-transmission losses caused by reactive load current; and
- KVA demand on the zone substation transformation capacity.

Capacitors can be categorised as follows:

- By construction: the large Ducon type with rated capacities from 388 kVAR to 888 kVAR and the smaller, modern rectangular cans rated from 100 kVAR to 373 kVAR;
- By fuse design: externally fused cans and internally fused cans; and
- By connection: series and parallel combinations.

1.11.1.1 *Asset Specification*

Table 4-54 lists each zone substation capacitor banks location, manufacturer and year of manufacture

Table 4-54: Capacitor Bank Information

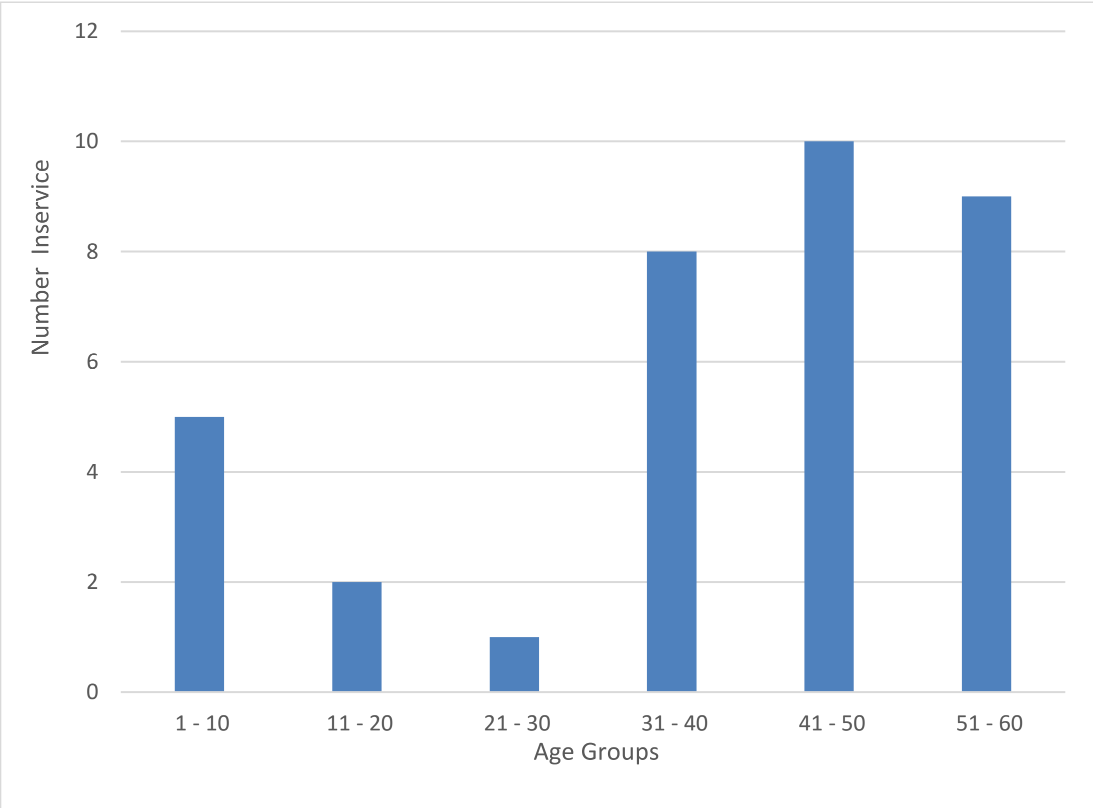
No.	Description	ZSS	Year Made	Age	Manufacturer	I – Indoor O – Outdoor
1	NO.1 CAP BANK	AW	1966	56	DUCON	O
2	NO.3 CAP BANK	AW	1981	41	TYREE	O
3	NO.2 CAP BANK	BD	1968	54	ASEA	O
4	NO.3 CAP BANK	BD	1962	60	NISSIN/DUCON	O
5	NO.1 CAP BANK	BMS	2014	8	ABB	O
6	NO.1 CAP BANK	CN	1970	52	COOPER	O
7	NO.2 CAP BANK	CN	1967	55	DUCON	O
8	NO.3 CAP BANK	CN	1986	36	ASEA	O
9	NO.2 CAP BANK	COO	2007	15	AMP CONTROL	O*
10	NO.2 CAP BANK	CS	1976	46	ASEA	I
11	NO.1 CAP BANK	EP	1978	44	DUCON	O
12	NO.6 CAP BANK	EP	1978	44	DUCON	O
13	NO.3 CAP BANK M1	EPN	2015	7	ABB	O*
14	NO.1 CAP BANK	ES	1965	57	DUCON	O
15	NO.1 CAP BANK	FE	1981	41	ASEA	O
16	NO.2 CAP BANK	FE	1981	41	ASEA	O
17	NO.1 CAP BANK	FF	1976	46	COOPER	O
18	NO.1A CAP BANK	FW	1966	56	ASEA	O
19	NO.1B CAP BANK	FW	1981	41	ASEA	O
20	NO.3A CAP BANK	FW	1978	44	ASEA	O
21	NO.3B CAP BANK	FW	1982	40	ASEA	O
22	NO.1 CAP BANK	FT	1970	52	ASEA	O
23	NO.2 CAP BANK	FT	1980	42	ASEA	O
24	NO.1 CAP BANK	NT	2000	22	ABB	I
25	NO.1 CAP BANK	NH	1986	36	ASEA	O
26	NO.2 CAP BANK	NH	1988	34	ASEA	I
27	NO.1 CAP BANK	PTN	2019	3	ABB	O*
28	NO.2A CAP BANK	PV	2013	9	ABB	O*
29	NO.1 CAP BANK	SBY	1978	44	COOPER	O
30	NO.1 CAP BANK	SHM	2007	15	ABB	O
31	NO.1 CAP BANK	ST	1986	36	ASEA	O
32	NO.2 CAP BANK	ST	1985	37	ERO STRANSTROM	O

No.	Description	ZSS	Year Made	Age	Manufacturer	I – Indoor O – Outdoor
33	NO.1 CAP BANK	TH	1986	36	ASEA	O
34	NO.2 CAP BANK	TH	1986	36	ASEA	O
35	NO.1 CAP BANK	TMA	2015	7	ABB	**O**

*Represents Outdoor Modular Capacitor Bank

Figure 4–24 shows the current capacitor banks' age profile (the number of capacitor banks installed by year of manufacture:

Figure 4–24: Capacitor Bank Age Profile (Dec 2024)



JEN capacitor banks design life expectancy is approximately 40 years. The plan is to replace capacitor banks only when they reach the end of their average lives based on condition. The consequence of a capacitor bank failure is low.

A capacitor bank's life expectancy depends on the life and quality of its insulation system, its build quality and its installation location, i.e. indoor or outdoor (those installed outdoor are more susceptible to vermin and moisture ingress and accumulation of pollution).

1.11.2 RISK

This chapter includes information about capacitor bank risk profiles involving the way that asset class criticality is established, the risks posed by capacitor bank failures (including the various failure types and their possible consequences), other measures being introduced to manage asset risk, and a list of the various issues currently confronting capacitor banks.

This information specifically involves:

- Asset class criticality score (sub-asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Existing controls ;
- Asset Spares;
- Contingency;
- Future risks (involving other potential risk issues currently being managed).

Capacitor banks are generally reliable and the risk of failure is considered to be low. The major risks associated with capacitors are environmental, with respect to potential failures leading to oil spills.

Emerging risks for this asset class include:

- Ageing population of all component parts including CTs, VTs, reactors, earthing switches and cans;
- Deteriorating interior capacitor can insulation condition of fluid/oil/paper insulation system due to heat and electrical stress by being in-service;
- Corrosion of capacitor can enclosures resulting in fluid/oil leakage and soil contamination, particularly with large Ducon units;
- Expenditure prioritisation restricting timely replacement.

1.11.2.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). The results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN’s operational objectives. This is used to rank the importance of dissimilar sub-asset classes (e.g. transformers and buildings and grounds) to identify areas where risk should be managed first and control measures implemented.

The capacitor banks have an asset criticality score of AC1 (low) due to possible regulatory enquiry.

Zone substation capacitor banks are low criticality, low volume assets. They are installed in zone substations to reduce system losses, maximise asset utilisation and to provide reactive power compensation for heavy load conditions. The capacitor banks vary in size from 4 MVAR to 12 MVAR. They are time or VAR controlled, automatically or manually switched. Zone Substations can operate successfully without capacitor banks in service, however, transformation capacity may be limited at times of heavy loading.

1.11.2.2 *Spares*

As part of the criticality assessment, consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002). It was determined that adequate capacitor bank component spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team.

Critical Spares Assessment Procedure (ELE-999-PR-RM-002) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I

Furthermore, when assets are retired from service, consideration is given to retaining components or entire asset as spares to service existing aging fleet.

Limited spare capacitors are located within the Tullamarine store and AW zone substation storage area. They are suitable replacements for small capacitors cans at various zone substations. As small capacitor cans are depleted, new spares are purchased.

1.11.2.3 *Existing Controls*

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.5.4.3 and 4.5.4.4, together with initiation of replacement projects for assets determined to be in danger of a major failure.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the failed capacitor bank/components. Once determined, either components are replaced from stock or whole bank is retired and a replacement project actioned.

1.11.3 PERFORMANCE FACTORS

This chapter includes information about asset performance measures. Asset performance measures for JEN zone substation capacitor banks are designed to achieve a high level of reliability by undertaking a practical, efficient cost program of preventive and corrective maintenance, coupled with planned, economic replacement of capacitor banks before failure; to maintain quality of supply and mitigate the safety risk to personnel.

Specific capacitor bank operating measures (and condition monitoring) include the following:

- Condition monitoring tests: thermography; and
- On-line, non-disruptive monitoring surveys: Ultrasonic and UHF detection for air borne partial discharge signals.

1.11.3.1 *Performance requirements and targets;*

- Failure Prevention – avoiding catastrophic (unplanned outages of more than 24 hours) capacitor bank failures from occurring within zone substations - target zero per year.
- SAP records the failures and repairs performed on capacitor banks. This data is used as an indicator of performance. Over a 5-year period, there has been an average of 16 defects/failures per year. Based on the history of capacitor unit replacements, defect replacement of 6 capacitor cans per annum is expected.

1.11.3.2 *Assessment*

A number of factors are assessed to determine if individual assets of the capacitor bank group have a high probability that the unit will continue to reliably perform its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and actual performance are analysed and examined.

1.11.3.3 *Condition Assessment*

- All known (at the time) Polychlorinated Biphenyls (PCB) insulated capacitors were replaced in 2000. PCBs were used as an insulating liquid in electrical systems over a number of years, particularly in capacitors. PCBs create an environmental risk and are carcinogenic when burnt at low temperatures.

PCB contamination is defined as "scheduled" (>50 parts per million and 50g PCB) or "non-scheduled" (>2 and <50 parts per million). Most high voltage capacitors on the network are known to be PCB free, however there are a small number of capacitor cans referred to as large Ducon types and small capacitor cans which may contain PCB at levels greater than 50ppm. Recent disposal of some of these capacitors has confirmed they were contaminated

At ST zone substation some retired capacitor cans were found to be highly contaminated with PCBs. These cans were initially assessed to have >2 and <50 parts per million of PCBs. However, oil tests after they were decommissioned indicated very high levels of PCBs. Other distribution businesses within Victoria have experienced similar issues with these cap cans.

- Series reactors installed within the No.3 capacitor bank at CN were found to be defective due to severe cracks appearing in the epoxy resin body. The nature of the defect has affected the integrity of the epoxy resin which encapsulates reactors to restrain winding movement when energising the capacitor bank or during fault conditions. The reactors have since been replaced. This type of defect is monitored during monthly zone substation inspection.
- Some capacitor can families are suffering increasing failure rates. As these are identified they will be programmed for replacement.
- There was a history of the ST zone substation No.2 capacitor bank tripping on the current balance over several years. This had been occurring regularly and field crews were required to attend site and rebalance the entire capacitor bank, which involved the disconnection of each capacitor unit for testing. This exercise was time consuming and physically demanding and a waste of valuable resource time. The problem was related to a particular type of old capacitor cans. That is the ESTA PHFPF06.73 type cans and these were all replaced in 2009 with ABB CHD480B. In 2011, the disposal process began, and oil samples for the capacitor cans were found to contain PCB, even though the capacitor cans were labelled PCB-free. All capacitor cans fitted with PCB free labels shall have the labels removed, and all capacitor can oil leaks are to be treated as PCB contaminated unless proven otherwise.
- The new No.1 capacitor bank at PV commissioned in 2011 was producing a noticeable noise level as compared to a similar unit at SHM. The project manager was made aware of the issue and the issues were addressed in liaison with the manufacturer ABB.
- Capacitor unit spares will be assessed and stock levels adjusted accordingly. During 2011, 6 spare capacitor cans were purchased for CN, NH, ST. During 2012, 4 spare capacitor cans were purchased for FT and NH.
- Fuses on the capacitor cans at FF and FT have been operating. These fuses were under rated and have been subsequently replaced at FF. An assessment of the fuse rating for both capacitor banks at FT was undertaken and it was identified that the problem was with the fuse holders. This was rectified, however, the issue will be monitored
- In November 2013, the No.1 capacitor bank at CN was discovered to have leaking cans. ABB ordered extra cans to replace them, and the bank was returned to service in February 2014.

- A leaking Ducon cap unit was discovered on the No.1 capacitor bank at ES in 2017. PCB 3ppm. An assessment of the oil leak will be continued. Spare replacement will be made if required.
- ABB Abbacus (Modular Capacitor Banks): Ausnet have had an explosive failure of one of their cap banks at PHI. JEN have 5 of these at EPN, PV, SHM, FW1 and PTN. The VAR controls have been disabled at EPN, PV & SHM and PTN (FW #1 is already suppressed as a new normal). A 1m. exclusion zone around the capacitors have been put in place when they are live. Further assessment is required to manage this issue.

- Following recent issues identified with the ABB ABBACUS capacitor banks (external to JEN), Siemens Simoprime A4 metal clad switchgear, aging switchgear which is not arc fault rated, and the blue book new requirement for arc flash study, JEN has formed a working group to assess the risk to employees when working in HV and LV environments.
- Optical switchgear sensing of electrical arc faults is a technology currently available to minimise fault damage and potentially provided a safer work place. This system is recommended for assessment and possible retrofitting. Similarly, this could be included in the switchgear specification and modular capacitor bank enclosures.
- Further to the above, An Ultra-Fast Earth Switch (UFES) is a device combined with optical detection of arc flashes, which applies a three phase to ground short circuit to minimise local damage. Consideration of the impact on the upstream transformers and switchgear that will be exposed to a 3 phase short circuit is necessary. This system is recommended for assessment and possible retrofitting. Similarly, this could be included in the switchgear specification and modular capacitor bank enclosures.

1.11.3.4 *Utilisation*

Capacitor banks installed across JEN zone substations are time or VAR controlled, automatic or manually switched. They help manage kVA demand on the zone substation transformation capacity.

Many capacitor banks have been switched off at the request of AEMO, as transmission voltages were too high due to reduced loading and changes in generation (reduced Var consumption) with the retirement of Hazelwood Power Station. (Long transmission lines act as capacitors when loading is low).

1.11.3.5 *Control Effectiveness*

Controls employed (inspection, condition monitoring & maintenance) and condition based replacements completed are identified below. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table:

Table 4-55: Controls Effectiveness

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Capacitor bank or cans failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed	Nil
Regulatory & compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil – costs not significant, average of 16 defect/failures pa

1.11.4 LIFE CYCLE MANAGEMENT

This chapter includes information about capacitor bank asset management practices, including key capacitor bank strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset lifecycle management options;
- asset creation (including asset acquisition and asset spares);
- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- asset replacement and disposal; and
- future improvements.

1.11.4.1 *Lifecycle management options*

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure

There are three feasible lifecycle management options:

- Condition monitoring and preventive maintenance with condition based replacement. Properly electrically protected and adequately maintained, a capacitor bank's life expectancy can exceed 50 years. This option is preferred as the best economic and risk based option.
- Corrective maintenance with fixed, age-based replacement at its nominal life of 40 years, (irrespective of condition). This option is not considered to be cost-effective, as assets in good condition (based on historical performance and defects) will be replaced prematurely. Condition monitoring and preventive maintenance can be employed to maximise asset life, and asset then replaced to mitigate against safety and reduced reliability risks.
- Corrective maintenance with run-to-failure replacement. This is not a realistic option due to the criticality of the assets, the impact on health and safety, impact on supply reliability and the long lead-time for replacement. The risk to the network due to long lead times when procuring replacement assets can be mitigated by purchasing spares.

1.11.4.2 *Creation*

New capacitor banks are installed if the Future Network and Planning team deem the need and necessity for VAR compensation at zone substations across JEN.

Capacitor banks are typically purchased under a period contract in alignment with primary plant manual and specification requirements. Incorporation of the elements of this document, particularly opportunities for future improvements, will determine the requirements of plant specification.

1.11.4.3 *Asset Operation and Maintenance*

This section provides information about the current asset maintenance program for Capacitor Banks.

The current asset maintenance program involves:

- Monthly inspection conducted by operational employees;
- Annual Inspection conducted by engineering staff;

- reactive and corrective maintenance;
- preventive maintenance; and
- condition-based monitoring.

Inspections of capacitor banks shall be performed monthly by operators as part of the zone substation inspection program. In addition capacitor banks will be viewed as part of the annual zone substation engineering audit.

Whenever access to the capacitor bank is required for repairs, the opportunity shall be used to inspect the entire installation. These inspections shall include the capacitor cans, inrush current limiting reactors, and current transformers for any of the following:

- signs of tracking or cracks on insulators;
- tracking, cracking or damaged inrush reactors;
- blown external fuses;
- integrity of all lead connections to equipment;
- if fitted, bird and animal covers on bushings are in place and have not perished; and
- leakage of insulating fluid or any sign of capacitor container swelling.

Inspection of HV connections is important because some indoor capacitor banks cannot be readily scanned with an infrared camera.

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified defects (or both), resulting in the repair.

Corrective maintenance is performed to repair defects identified during in-service inspection or routine maintenance and by thermal surveys.

- Faults: Immediate response required to investigate and may include some corrective actions
- Defects: Following a fault investigation, there may be some further correction actions planned in the future.

Causes of failures are:

- animal and bird interference, causing external flashover between phases or to earth structures and tracking on insulator surfaces;
- lightning;
- high resistance connections;
- ageing of dielectric material in capacitor elements;
- moisture ingress and corrosion; and
- harmonics leading to overheated capacitor cans.

Capacitor bank failure mode can include:

- external fuse fatigue;
- fails to carry load; and
- fails to insulate.

Capacitor can faults are detected by current balance or voltage balance protection schemes in addition to conventional over current and earth fault protection schemes. Fuses and connections of capacitor cans can be repaired or replaced but repair of the actual capacitors is neither economical nor practical. The faulty capacitors are normally replaced and the banks are re-balanced.

The preventive maintenance program shall consist of:

- Maintenance of indoor capacitor banks and their earth switches is scheduled on a 6 yearly cycle. There are 2 indoor cap banks;
- Maintenance of cubicle type capacitor banks and the NT capacitor bank including their earth switches are scheduled on a 4 yearly cycle. There are 6 cubicle type cap banks;
- Maintenance of all outdoor capacitor bank and their earth switches are scheduled on a 6 yearly cycle. There are 27 outdoor cap banks; and
- Where capacitor banks are installed indoors at CS and NH or outdoors with a roof, then it is recommended that a maintenance cycle of 4 years is considered instead of 6 years.

The capacitor cans, reactors, and current transformers are largely maintenance free items and therefore in the past were not scheduled for routine planned maintenance. This was an outcome of a previous RCM assessment. Maintenance was planned to be reactive based on the condition of the plant as detected by inspections, operations and condition monitoring.

The maintenance of indoor and, more recently, outdoor capacitor banks has been reviewed and reintroduced for the following reasons. This mainly focuses on cleaning the enclosure, floors, and porcelain surfaces, inspection of HV connections and maintenance of exhaust fans (where applicable) and the earth switch. Inspection of HV connections is important because some indoor capacitor banks cannot be readily scanned with an infrared camera. The capacitor bank earth switches are permanently installed safety devices which can develop high resistance connections over time. Maintenance is necessary to ensure continued functionality. Outdoor capacitor bank enclosure conditions and removal of debris are the main drivers.

Maintenance of indoor capacitor banks and enclosures is deemed necessary because of the accumulation of dust and debris within the enclosure that under normal circumstance would not be washed down by rain. The accumulation of dust will eventually impact on the dielectric strength of insulating surfaces, which could potentially lead to external tracking and a flashover. The level of dust could also present a health concern to personnel working within the enclosure.

The capacitor bank earth switches are permanently installed safety devices which can develop high resistance connections over time. Maintenance is necessary to ensure continued functionality.

Preventive maintenance of the capacitor installations and earth switches should be coordinated with the capacitor bank circuit breaker maintenance where possible.

1.11.4.4 *Condition-based monitoring*

Infra-red thermographic surveys covering all HV plant such as capacitor banks are also included in the annual thermal surveys. Not all capacitor banks components are directly visible due to their design. It is not normally possible to detect a thermal defect for modular or indoor capacitor bank using a thermal camera.

1.11.4.5 *Asset Replacement/Disposal*

There are 35 capacitor banks of various capacities installed across the JEN. The large mineral oil filled capacitor can (Ducon unit) are reliable and there have been no known catastrophic failures. However, there have been some capacitor cans which had developed oil leaks, and one capacitor can from the EP No.3 capacitor bank was replaced.

The Ducon bulk oil capacitor cans cannot be repaired and the only option is to replace with a spare. While there are spares available for some of the Ducon bulk oil capacitor cans, as of 2018, there are no type OF7881 spare cap cans available for a total population of 24 cap cans of similar make and model across the JEN. In the event of a failure of these capacitor cans, the only option may be to replace the capacitor bank. This will be assessed when the failure occurs. In some circumstances, the replacement of a large Ducon capacitor can will be assessed for replacement with a modern capacitor can.

From 2008 through to 2014, forty one capacitor unit failures and replacements have been recorded. From 2013 to 2022, twenty three capacitor unit failures have been recorded. Based on the history of capacitor unit replacements, defect replacement of 6 capacitor cans per annum is expected.

As identified in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

Table 4-56 lists the forecast replacement volumes for zone substation capacitor banks from 2024 to 2030, based on these drivers.

Table 4-56: Notional Forecast Replacement Volumes - Zone Substation Capacitor Banks

Replacement Volumes – Zone Substation Capacitor Banks		Year						
	Unit	2024	2025	2026	2027	2028	2029	2030
Replace Ducon capacitor bank	ea	-	-	1	-	1	-	-
Replace capacitor cans	ea	6	6	6	6	6	6	6

(1) This table does not include the volume of installations planned that are classified as augmentation works.

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how JEN prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-57 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure.

Table 4-57: Specific Drivers - Zone Substation Capacitor Bank Replacements

Driver	Risk/Opportunity Description	Consequence
Asset Integrity Regulatory Compliance	Equipment failure/frequent loss of asset integrity	Regulatory non-conformance and caused by issues with power factor correction
Asset Integrity Health, Safety, and Environment	Equipment failure	Capacitor bank may explode, and porcelain/other fragments may be expelled at the risk of employee safety
Health, Safety and Environment	There are a number of capacitor cans referred to as large Ducon types that may contain high Polychlorinated Biphenyls (PCB) levels (>50 ppm). PCBs were used as	PCBs create an environmental risk and are carcinogenic in nature.

	an insulating liquid in electrical systems over a number of years, particularly in capacitors.	

The volumes of work required and associated capital and operational expenditures ensure that the consequences identified in the table above are addressed to maintain network performance and manage risks. This prudent approach ensures that the long-term interests of customers are maintained.

Typically, when capacitor cans are retired or replaced, they are drained of oil, which is tested and disposed of separately. In order for the capacitor cans to be fit for transportation, a certificate must be obtained to ensure the capacitor can is free of PCBs so it can be appropriately transported.

1.11.4.6 *Future Improvements*

JEN's technology strategy involves investigating new technologies to improve network reliability, safety, environmental care, and reduce costs. Future improvements being explored for this asset class involve the following:

- Following recent issues identified with the ABB ABBACUS capacitor banks (external to JEN), Siemens Simoprime A4 metal clad switchgear, aging switchgear which is not arc fault rated, and the blue book new requirement for arc flash study, JEN has formed a working group to assess the risk to employees when working in HV and LV environments.
- Arc fault detection: Optical arc flash sensing of electrical faults is a technology currently available to minimise fault damage and potentially provided a safer work place. The arc fault detection provides faster fault clearance time, and is interlocked with a current check relay. This system is recommended for assessment and possible retrofitting. Similarly this could be included in the switchgear specification and modular capacitor bank enclosures.
- Further to the above, An Ultra Fast Earth Switch (UFES) is a device combined with optical detection of arc flashes, which applies a three phase to ground short circuit to minimise local damage. Consideration of the impact on the upstream transformers and switchgear that will be exposed to a 3 phase short circuit is necessary. This system is recommended for assessment and possible retrofitting. Similarly this could be included in the switchgear specification and modular capacitor bank enclosures.
- It is recommended to reassess the RCM analysis conducted back in 2000 to now follow the IEC 60300 0-3-11,12 and 14 RCM guidelines and quantitatively determine the maintenance intervals for all sub-asset classes.
- The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information on capacitors and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote the efficiency and reliability of substation management.

1.11.5 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determines the information required to manage and operate an Asset Class.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information requirements to support these objectives (see Table 4-58). Table 4-61 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class. Table 4-60 provides the information initiatives required to provide the future information requirements identified in Table 4-59. Included within Table 4-60 is the risk to the Sub-Asset Class from not completing the initiative.

All of the information required by the transformer Sub-Asset Class is available within JEN's current business systems.

Table 4-58: Capacitor Bank Business Objectives and Information Requirements

Business Objective	JEN Information Sources	Externally Sourced Data
Maintain safety, availability and reliability of Capacitor Banks	SAP ERP (enterprise resource planning) DrawBridge (drawing management) Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee Alerts – from DB's and Government Organisations and manufacturers Manufacturing manuals AS/IEC standards

Table 4-59: Capacitor Bank Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Capacitor Bank - Asset Creation	• Specifications and tender responses • Zone Substation Primary Design Standard • New asset project progress reporting. Completion recorded in SAP • Asset register in SAP		• High – Regulated to maintain supply reliability, safety and quality of supply. Also, a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of Capacitor Banks via inspections and audits	Asset register SAP, with details of each asset and significant components; • Manufacturer • Type • Equipment description • Construction year • Basic specification • Location: Zone substation name • Address • SAP Maintenance Reports • Performance history - Daily situation reports - Investigation reports (ECMS) - Plant defect reports • DrawBridge - Single line diagrams - plant data - OEM manuals	• Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	- design drawings/layouts • SMI's – (Standard maintenance instruction) • SAP notifications and work orders activities performed, and components replaced. • Details of work completed recorded in SAP		
Maintain functionality of Capacitor Banks via Preventive Maintenance	• Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. • Scheduled task description, timing and completion recorded in SAP; SMIs held in SharePoint, Policies & Forms • Manufacturers maintenance manuals • SAP notifications and work orders activities performed and components replaced • Details of work completed recorded in SAP • Details of spare equipment located in SAP • OPEX & CAPEX cost reporting recorded in SAP	• Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply
ACS Review	• Condition data • Fault/failure data • Maintenance & replacement costs • AMS		• Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-60: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph the instrument transformer nameplate and attach to SAP equipment Access all information via electronic tablet in the field Update asset data in SAP for missing or incorrect data	To improve analysis and decision making Asset data available from business systems saving on site trips	Poor efficiency in accessing asset data	Asset Data as per RCM and SAP requirements

1.12 ZONE SUBSTATION BUILDINGS AND GROUNDS

1.12.1 INTRODUCTION

The Zone Substation Buildings and Grounds asset sub-class strategy applies to zone substation buildings, enclosures, transformer oil containment, security and grounds. It aims to ensure that zone substations are maintained so that site safety and security is maintained and that buildings and enclosures remain weather proof and a reasonable standard of appearance is maintained so that the enclosed equipment is protected.

The Zone Buildings and Grounds Asset Sub-Class Strategy provides an asset overview and identifies the best strategies and plans for managing assets over their lifecycles.

The asset class strategy is based on key information about each asset (including risk, performance, capital expenditure and operational expenditure). Based on this information, the asset class strategy provides details about the JEN’s zone substation buildings, enclosures, transformer oil containment, security, and grounds and comprises five key areas:

- Asset class profile includes information about the type, specifications, life expectancy and age profile of zone substation buildings in service across the JEN;
- Asset strategy outlines zone substation buildings, enclosures, security and grounds asset management practices. This includes key strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and programs of work. See Section 4.6.4 Life Cycle Management;
- Asset risk includes information about asset risk, including causes and consequences. See Section 4.6.2 Risk;
- Asset performance provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with zone substation buildings, enclosures, security and grounds management; and
- Asset expenditure assessment provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

The asset class strategy is reviewed every three years to ensure alignment with the corporate business plan, strategy and objectives and to account for any additional asset performance and risk information.

This chapter includes information about the type, specifications, life expectancy and age profile of the zone substation buildings and grounds in service across the JEN.

Zone Substations buildings contain equipment that is used to transform sub-transmission voltages to distribution voltages and to act as controlling points between differing high voltage networks.

1.12.1.1 *Asset Specification*

There are a total of 33 JEN sites consisting of zone substations, switching station and HV customer substations containing JEN 66kV sub-transmission feeders and switchgear.

Each of these sites are secured with perimeter fences, locked buildings and gates. Site identification nameplates and danger HV signs are installed on the fences and authorised personnel are issued with a key to access zone substations. The security fencing at customer substations at NEI, SSS and VCO consists of standard chain wire mesh, whereas the remaining 30 zone substations fences were upgraded to welded mesh including brick/concrete panels and timber panels. The three customer substations have been secure and there are no historical security issues as they are located within customer operational premises.

The JEN zone substation perimeter fences generally consist of a combination of Welded Mesh panels topped with concertina “Tiger Tape”, brick walls, or timber panels. In addition, timber panels topped with barbed wires are used adjacent to residential properties.

Table 4-61 lists the population, type and age for this asset class.

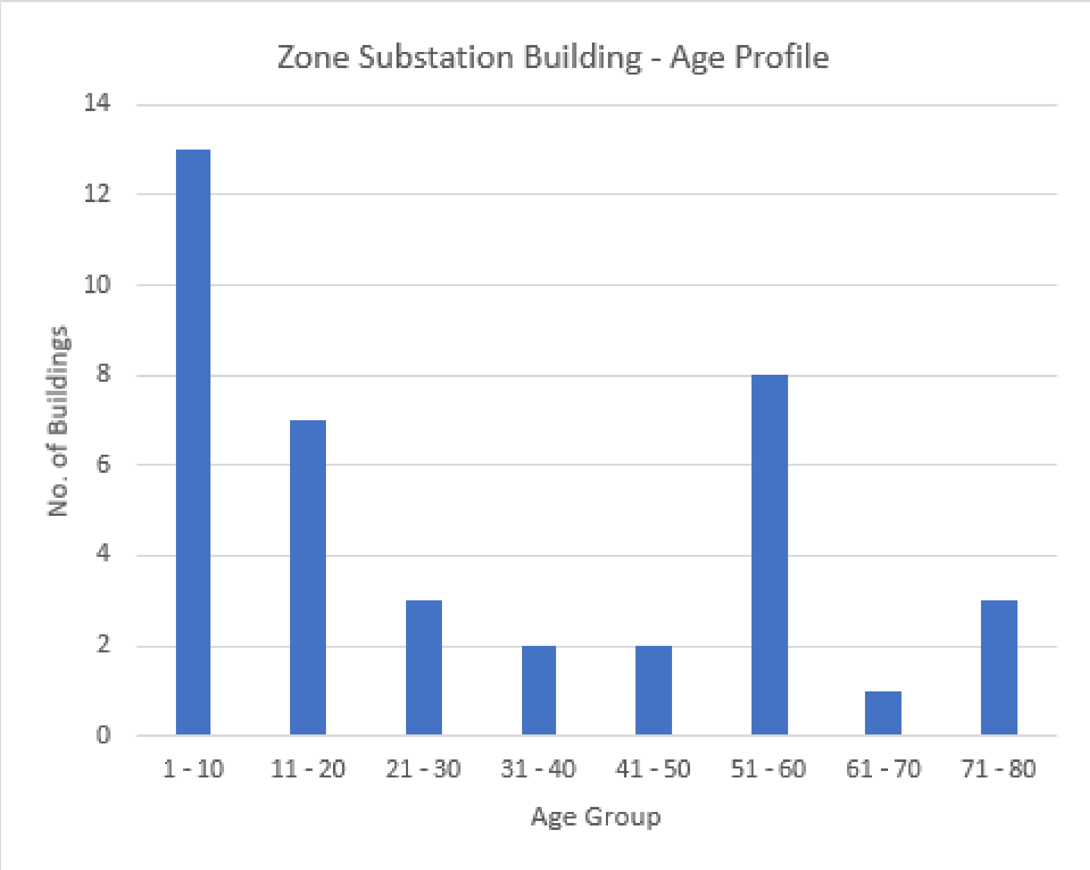
Table 4-61: Information requirements Zone Substation Buildings

Zone Substation	Building Type	Building YOM	Upgraded Security Fence	Fence YOM	Fence Material
AW (Airport West)	Brick	2017	YES	2008	Welded Mesh
BD (Broadmeadows)	Brick	2019	YES	2008	Welded Mesh
BLT (BLTS)	Brick	Customer Owned	YES	Customer Owned	Chain wire Mesh
BMS (Broadmeadows South)	Brick	2014	YES	2014	Weld Mesh/Timber
BY (Braybrook)	Brick	1950	YES	2011/1998	Brick/Timber
CN (Coburg North)	Brick	1967	YES	2008	Welded Mesh
COO (Coolaroo)	Tin	2007	YES	2007	Welded Mesh
CS (Coburg South)	Brick	1976	YES	2010	Brick/Timber
EP (East Preston) A	Tin	1952	YES	2009	Welded Mesh
EP (East Preston) B	Brick	1968			
EPN (East Preston)	Brick	2015	YES	2015	Brick/timber/Welded Mesh
ES (Essendon)	Brick	1965	YES	2010	Brick/Timber
FE (Footscray East)	Brick	1967	YES	2010/2022	Welded Mesh/Timber
FF (Fairfield)	Brick x 2	1949/2019	YES	2019	Timber

Zone Substation	Building Type	Building YOM	Upgraded Security Fence	Fence YOM	Fence Material
FT (Flemington)	Brick	1970	YES	2010	Welded Mesh/Timber
FW (Footscray West)	Brick	1966	YES	2011	Brick/Timber
HB (Heidelberg)	Brick	1966	YES	2008	Welded Mesh
MAT (Melbourne Airport)	Tin	2015	YES	2015	Welded Mesh
NEL	Brick	2022	YES	2022	Welded Mesh
NEI (Nilsen)	Cement sheet	1994	NO	Customer Owned	Chain wire Mesh
NH (North Heidelberg)	Brick	1973	YES	2010	Brick/Welded Mesh
NS (North Essendon)	Brick x 2	1952/2017	YES	2018	Timber
NT (Newport)	Brick	1970	YES	2009	Welded Mesh
PTN (Preston)	Brick	2019	YES	2019	Welded Mesh
PV (Pascoe Vale)	Brick	2011	YES	2010	Welded Mesh/Timber
SBY (Sunbury)	Brick	2018	YES	2008	Welded Mesh
SHM (Sydenham)	Brick	2008	YES	2008	Welded Mesh
SSS (Somerton Switching Station)	Tin	2001	NO	Customer Owned	Chair wire Mesh
ST (Somerton)	Brick	1985	YES	2009	Brick/Welded Mesh
TH (Tottenham)	Brick	1984	YES	2008	Welded Mesh
VCO (Visy Board Coolaroo)	Brick	Customer Owned	NO	Customer Owned	Chain Wire Mesh
WGT (West Gate Tunnel)	Concrete	Customer Owned	N/A	N/A	N/A
TMA (Tullamarine)	Brick	2015	YES	2015	Welded Mesh
YVE (Yarraville)	Brick	2013	YES	2013	Welded Mesh

Figure 4–25 shows the current zone substation building age profile.

Figure 4–25: Zone Substation Building Age Profile (Dec 2024)



It can be seen 11 buildings are over 50 years old and 13 are over 40 years old, which indicates considerable investment in building replacement in future years.

The nominal life of zone substation buildings is 90 years for masonry type buildings.

The life expectancy of the zone substation buildings depends on the quality of materials used in construction, the presence of asbestos and the outcome of civil engineering audits.

All fences will be assessed for condition and will be replaced when necessary.

The nominal life of timber zone substation fences approximately 20 years and 40 years for the welded mesh fences.

The life expectancy of the zone substation fences depends on the quality and type of materials used in construction, such as steel posts or timber panels and posts.

1.12.2 RISK

This chapter includes information about zone substation buildings, enclosures, security and grounds risk profiles involving the way that asset class criticality is established, the risks posed by their failure (including the various failure types and their possible consequences), other measures being introduced to manage asset risk, and a list of the various issues currently confronting zone substation buildings and grounds.

This information specifically involves:

- Asset class criticality score (sub-asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;

- Current risks;
- Existing controls ;
- Asset Spares;
- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

The major risks associated with the surrounds and buildings of substations are:

- Safety to employees during operation and maintenance;
- Supply reliability due to lack of access for operation;
- Equipment failure due to animals/birds/insects;
- Poor public perception due to appearance if in an unkempt state;
- Vegetation covering vent holes might result in equipment overheating;
- Public access safety risk due to unsecured doors, fences and windows;
- Access by unauthorised persons;
- Water leaking through roofs, or conduit;
- Environmental oil loss; and
- Vandalism.

Failure to inspect Zone Substations and to undertake grounds, fences and building maintenance on a regular basis, can lead to prolonged security breaches, public safety concerns, asset damage leading to mal-operation of equipment and supply reliability issues.

Emerging risks include:

- Ageing building collapse;
- Possible forced removal of asbestos containing materials;
- Environmental contamination due to inadequate or deteriorated oil containment systems; and
- Increased terrorism threats; security breaches.

Greater incidents of temperature, and storm extremes and grass and bushfire threats.

1.12.2.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). The results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN’s operational objectives. This is used to rank the importance of dissimilar sub-asset classes (e.g. transformers and buildings and grounds) to identify areas where risk should be managed first and control measures implemented.

The buildings and grounds has an asset criticality score of AC4 (High) due to operational and health and safety consequences associated with unauthorised access. Also the building itself protects the internal equipment from environmental damage.

Zone substations represent critical infrastructure. Access to switch rooms and switchyards is necessary to operate the zone substations, indoor electrical equipment needs to be kept dry and JEN has an obligation to provide a safe work place. Life extension to security systems such as gates, fences, windows and doors will form part of this asset class strategy.

1.12.2.2 *Spares*

It was determined that Buildings and grounds facilities are constructed of commercially available hardware and equipment, therefore any required material can be purchased from suppliers. Spares requirements for critical assets using the Critical Spares Assessment Procedure (ELE-999-PR-RM-002) is not relevant in this case.

1.12.2.3 *Failure Modes*

Likely failure modes include:

- Corrosion of steel structures, fence posts, gates and wire mesh;
- Corrosion of steel roofing, gutters and downpipes;
- Water ingress due to holes in roof, blockages of roof gullies and spouting, poor conduit seals;
- Timber fencing and building weatherboards deterioration due to rotting and splitting;
- Timber building collapse due to timber rot, or termite infestation;
- Access prevention due to overgrown grass, shrubs and trees;
- Security breaches due vandalism; and
- Vermin infestation.

1.12.2.4 *Existing Controls*

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.6.4.4, together with initiation of replacement projects for assets determined to be in danger of major failure.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the assets. Once determined, temporary repairs can be actioned followed by purchase of commercial materials and installation of permanent repairs or refurbishment.

1.12.3 PERFORMANCE FACTORS

This chapter includes information about asset performance measures. Asset performance measures for JEN substation buildings and grounds are designed to achieve a high level of reliability by undertaking a practical, efficient cost program of preventive & corrective maintenance, coupled with planned, economic replacement/upgrade of substation buildings, fences and ground assets before failure in order to mitigate the safety risk to personnel and contractors.

SAP records of buildings and grounds defects and repairs are available and there is no significant increase in defects and repairs over previous years. A register of break-ins is available.

1.12.3.1 *Requirements*

The performance objectives of zone substation buildings and grounds are to, in a cost-effective and efficient manner:

- ensure public / employee safety; reduce the risk of network outages; minimise unauthorised access; protects the internal equipment from environmental damage; and maintain the appearance of substation grounds to a standard that meets community expectations.

The performance objectives will aim to ensure that all zone substations are:

- inspected at regular intervals to ensure that these substations do not compromise public or employee safety and remain in a serviceable condition; and
- maintained so that site safety and security are maintained and that enclosures and buildings remain weather proof,
- maintained at a reasonable standard of appearance so that the enclosed equipment is protected.

Specific substation building and ground performance measures include the following:

- Monthly operator security inspection;
- Annual zone substation audits; and
- 3-yearly civil audits of all JEN zone substation buildings, structures and foundations for HV plant, fences, and transformer sound enclosures.

1.12.3.2 *Assessment*

A number of factors are assessed to determine if individual assets of the buildings and grounds group have a high probability that the unit will continue to reliably perform its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and actual performance are analysed and examined. The following reports provide data for these areas:

- SAP records of building and grounds defect and repairs as a notification and PM order; and
- 3-yearly civil audit reports.

1.12.3.3 *Condition Assessment*

This section provides information about zone substation buildings and grounds, as well as general information about other potential issues.

AW Transformer Bund Drainage Gate Valves

The gate valves at AW were rusty and inoperable. They were cleaned and deemed serviceable. When a valve needs to be replaced, it is recommended that it be replaced with a superior valve constructed from stainless steel and having a high-grade seal (e.g., Teflon).

CS and NH Building Windows

Building window frames are showing signs of severe corrosion. It is recommended that all ZSS building windows are assessed and a project prepared for replacement starting with CS and NH.

Windows

Building window latches were installed for pressure venting in the event of a catastrophic HV fault. The latches lose their tension and the windows drift open. Although this is not an immediate safety concern, these windows should remain closed to prevent vermin and rain and debris from entering. All windows will be assessed and the latches adjusted or renewed.

FT Wall cracking and foundation subsidence

Some evidence existing of brick wall cracking most likely due to foundation subsidence. A Geotechnical investigation and dilapidation report has been conducted and remediation work is recommended.

FW No.3 Transformer Enclosure Roof

The civil engineering report obtained in February 2013 for No.3 Transformer Enclosure Roof at ZSS FW recommended that JEN continue monitoring the cracks on the underside of the roof slab. Any spalling of concrete or discolouration due to corrosion of steel reinforcing will require further investigation and probable replacement of the roof. There is no plan to replace the enclosure roof. The No.3 transformer will be decommissioned once the switchgear replacement project has been completed, however precautions and controls must remain in place and maintained.

MAT Control Room Building

Since 2012, the portable control room building has evidence of rust and degradation of paint on the external cladding. Continued monitoring will continue.

NS Control Room Roof

The asbestos roof on the NS control room has leaked in the past onto the HV switchgear. During the transformer replacement project, repairs of the roof were undertaken, however due to the condition of sections of the roof and to guarantee long term security of the station it is recommended to replace the roof. This activity will be coordinated with the relay replacement project.

YVE and Rabbit Infestation

YVE and SBY both have rabbits entering the switchyards. In recent times, rabbits have eaten through control cables at SBY and resulted in a cap bank step switch operating hundreds of times and destroying itself. Regular baiting programs at YVE and SBY may be necessary to mitigate this risk. New fence and concrete plinth's have been installed which has reduced the extent of the problem.

AW and SHM EGOWS

The Extended Gravity Oil and Water Separation (EGOWS) system at AW and SHM have been in service for several years and they both have been cleaned and maintained in 2013. In the event of a major loss of transformer oil, the EGOWS pits will contain 100% of the oil. An Operation and Maintenance policy has been prepared and maintenance plan has been created in SAP. Dead birds and debris are being blown in the EGOWS pits and said pits may require maintenance. The maintenance plan for the EGOWS has been initiated with a 10 years interval. A chemical treatment program has been implemented as a trial to control the growth of algae. Over time the success of the trial will be monitored and the EGOWS maintenance interval will be reassessed.

ST Storm Water Entry

Storm water was found entering the cable pits underneath the switchboard at ZSS ST. The conduits entering the cable pits from outside the ZSS have been sealed up to prevent future entry of storm water in the cable pits and possible corrosion of the metal clad switchgear. This work has not be entirely successful and new drainage system is required to prevent water entry.

YVE Control Room Building

Soon after commissioning YVE in 2014 the brick control room has suffered from structural damage. The control room building has developed significant wall cracks in the external brickwork distorting door frames and jamming doors. An independent civil inspection report has been prepared to address the identify actions required to address the issues. Further site remediation work is recommended.

A Geotechnical investigation and dilapidation report has been conducted and remediation work is recommended.

Modular Building water entry

Over time, several buildings have been observed to be leaking water underneath the personnel and maintenance access doors. It is recommended that a survey be undertaken for all ZSS building (Brick, portable modular etc) for evidence of any water ingress.

Security Upgrades

The Critical Infrastructure Plan and its supporting document referred to as the Security Management System, identified JEN zone substations as high-risk sites from a malicious and opportunistic perspective. In response, a program to upgrade the security fences at all JEN zone substation sites has been put in place. With the exception of NEI, VCO and switching station SSS, all sub transmission sites containing JEN assets have had their fences upgraded in accordance to the ENA - 003 Guidelines for Unauthorised Access to Electricity Assets.[7]

VCO and SSS are located in customer owned premises areas and enclosed by additional perimeter fences.

Security assessments were conducted in 2017 and indicates a need for systemic improvements in security control measures across JEN's Zone Substations. Three areas of concern were identified:

[redacted]

Site lighting - The current lighting arrangements amount to an inadequate deterrent measure for unauthorised access to the sites after dark. It also fails to aid in the detection of unauthorised access by neighbours or passing traffic. Of greater risk, is that JEN personnel or contractors are required to enter un-lit sites when attending at night, potentially to attend to maintenance issues caused by vandalism stemming from unauthorised access to the site. Personnel may therefore be unable to assess whether other persons are on site.

[redacted]

Recommendations are included in Section 4.6.5 Future Improvements.

Oil Containment

The original installation of oil containment bunds in JEN Zone Substations did not include the sealing of the bunds or the complete management of oil leaks on the site. Because the bunds are not sealed chronic oil leaks can lead to contamination of the soil and ground water. A program has been developed to complete the sealing of all unsealed bunds and install triple interceptors (Humeceptor's) in the drainage from the bunds to manage the small oil leaks that occur on transformers over their operational life. Sealing of transformer bunds is yet to be completed at AW, BY, CN, CS, EP, FF, FT, including the rollout of Humeceptor as required.

The installation of Humeceptors and the sealing of existing bunds are included in the SOW for all major projects at JEN Zone Substations. In addition a proactive program has commenced that aims to

[7] reference

address one substation per year on a priority basis where no major works are planned in the short to medium term. Zone substation BY is planned for bunding upgrade in 2021-2025.

Appendix G has the bunding status for all of the JEN zone substations.

Humeceptors

The introduction of Humeceptors to separate oil from storm water, required the associated drainage valves to remain normally closed. This has created an environment where algae will grow within the transformer bund (Oil containment area) and presents a health and safety risk (Trip hazard) to all personnel entering the area.

An innovative water filter ([redacted]) to prevent petrochemicals(Transformer oil) oil loss into the environment has been trialled and installed at NEL and HB. Early assessment of the [redacted] performance is promising, however a primary particle filter must be installed within the NEL and HB bund pits to prevent the [redacted] unit blocking up and the bunds filling with water. These particle filters will need to be cleaned regularly.

It is recommended that all existing and new transformer installations are fitted with a [redacted] system.

Control Building Roof Assessments

Condition of the control building roofs is assessed during the annual gutter and drainage inspection.

Refer to Appendix H for listing and status of control building roofs.

Installation of Handrails on Platforms & Fixed Ladders at all Zone Substations

After a slip injury from a platform access ladder an audit was conducted in early 2013 and identified zone substations that required the installation of hand rails for platforms and fixed ladders (anti slip coating was applied to the ladder rungs). The work was completed in August 2013 at the following zone substations: ES, EP, FF, NS, NT and PV.

In November 2013 the JEN HSE Committee requested that the inspection of platforms at zone substations be added to the annual zone substation audit program. The decision was made by the Primary Plant group to extend the audit to platforms, ladders, stairs and handrails, and accelerate the audit process. By March 2014, all zone substations had been audited to the requirements of Australian Standard AS1657-2013 which covers the design, construction and installation of platforms, ladders, stairs & handrails. A report was completed and corrective action taken.

Switchyard Aggregate

The large aggregate used to cover all switchyards is perceived to be a possible trip hazard for employees. Although no evidence is available to substantiate this, ongoing assessment may be required in the future.

Graffiti and Murals

Graffiti on security fences and some buildings walls continues to be an issue for JEN and local residential areas. To maintain an good public image by deterring graffiti, and also save costs for its removal, murals will be painted at selected sites and monitored regularly. The Mural designs for ZSS FF has be determined through working with local residents, municipal council and contract artist.

Buildings - Basement venting

Various raised ZSS buildings which are fully enclosed(or open such as the COO switchrooms), with an unsealed floor/ground, and do not have ventilation or adequate drainage within the cable basements, have a tendency to accumulate moisture that results in the formation of effloresce salt deposits. This environment can corrode copper earthing conductors in contact with the salt, and has been observed at AW, COO, SHM and TMA. Further work is recommended to control moisture entering the area.

Control Building Air Conditioning

Control buildings containing microprocessor based protection, control equipment and battery systems, are required to operate within a temperature controlled environment. A Capital Program commenced in 2011 to install thermal insulation and air-conditioning equipment in the 21 ZSS identified as requiring the cooling to ensure the reliable operation of electronic/microprocessor based equipment. This involved the installation of 2 commercial air conditioners, doors to segregate the protection room and thermal insulation. This program has now been discontinued after the installation of air conditioning at ZSS CN was determined to be cost prohibitive to install the air conditioners as a standalone project as it involved replacing the station service transformers and the LV distribution board. Now, air conditioners are installed as part of a major building upgrade project.

Asbestos

The issue of asbestos within these building remains a potential health and safety risk. An asbestos assessment is conducted for all ZSS and a report is prepared with recommendation for any remedial work. It is essential to assess the recommendations in the report for every ZSS and assess/prepare an action plan for implementation to address the concern.

Civil Inspections

To manage the risk of structural failure within a ZSS, a Civil Engineering audit should be conducted every 3 years. Although this is scheduled in SAP, there have been difficulties in engaging an accredited contractor to perform the work for several years, This activity is long overdue and further work is required to complete.

1.12.3.4 *Utilisation*

The utilisation of these assets relates to the installation of primary plant/equipment and secondary equipment within buildings. The building assets are fully utilised in the majority of the zone substations and any plant/equipment additions would require the extension of the buildings. However, any modification, change or expansion is assessed on a case by case basis. All new zone substation buildings are designed for the final ultimate arrangement as per the system design requirements.

1.12.3.5 *Control Effectiveness*

Controls employed (inspection, condition monitoring & maintenance) and condition based replacements completed are identified below. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table:

Table 4-62: Controls Effectiveness

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Buildings, fences and civil assets failure – people safety and or environmental impact	Asset Management strategy applied. Replacement projects completed	Many break-ins; register is available.
Regulatory & compliance	Failures result in non-compliance notices/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil

Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

1.12.4 LIFE CYCLE MANAGEMENT

This chapter includes information about zone substation buildings, enclosures, security and grounds asset management practices, including key zone substation buildings, enclosures, security and grounds strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset lifecycle management options;
- asset creation (including asset acquisition);
- asset maintenance (involving inspection, reactive and corrective maintenance and preventive maintenance);
- asset replacement and disposal; and
- future improvements.

1.12.4.1 *Lifecycle management options*

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure.

There are three lifecycle management options:

- Preventive maintenance with condition triggered refurbishment or replacement. Properly maintained buildings, enclosures and fences will ensure that they are structurally safe and will last at least as long as the assets installed inside them;
- Reactive maintenance with fixed, age-based replacement (irrespective of condition). This option is not considered to be cost-effective, as preventive maintenance can be employed to defer capital replacement; and
- Reactive maintenance with run-to-failure replacement. This is not a realistic option as the zone substation buildings house vital electricity distribution assets. This option can also pose severe health and safety risks to the JEN employees and contractors attending these sites.

The preferred asset lifecycle management option involves preventive maintenance, with the aim of achieving a life of 50 years for timber and 90 years for masonry type zone substation buildings. The replacement or major refurbishment of zone substation buildings will be triggered by the need to replace protection and control equipment, not by the age of the buildings alone. Civil and structural inspections of the buildings will indicate the need for repairs or refurbishment.

The issue of asbestos within these building remains a potential health and safety risk. The selection criteria for replacement or major refurbishment of zone substation buildings may be governed by legislation changes in the future, requiring the safe removal of all asbestos within specified timeframes.

1.12.4.2 *Creation*

The need for new buildings and the extension of the existing buildings or the procurement of new land is decided upon by the Network Capacity Planning and Development team in line with the growth forecasts. In addition to this new zone substation, buildings are sometimes required to cater for asset replacements as it is not always possible to replace assets in-situ. A new modular building standard has been prepared to standardise on one HV switchroom design and one control room design. This will deliver repeatable building modules which are built off site, reducing exposure to people working in HV environments and significantly avoid repeated design costs.

1.12.4.3 *Asset acquisition*

The replacement or major refurbishment of zone substation buildings will be triggered by the need to replace protection and control equipment, not by the age of the buildings alone. The following zone substations, subject to management approval of non-committed projects, will have new modular buildings where applicable:

- Various new Data Centres;
- Rebuild of Zone Substation Airport West;
- Rebuild of Zone Substation Broadmeadows;
- Rebuild of Zone Substation Coburg North;

1.12.4.4 *Asset Operation and Maintenance*

The current asset maintenance program involves

- Monthly inspection conducted by operational employees;
- Annual Inspection conducted by engineering staff;
- Three yearly civil engineering audit;
- Reactive and corrective maintenance; and
- Preventive maintenance.

Inspection and general maintenance shall be provided on Zone Substations that shall identify and rectify any defects, which relate to poor appearance, safety or environmental hazards.

A civil and structural engineering audit of Zone Substations shall be conducted on a 3-year cycle to monitor the integrity of all buildings and structures. Any deteriorated structures or buildings found shall be programmed for refurbishment or replacement.

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified defects (or both), resulting in the repair of:

- Building/Enclosure roofs;
- Civil, masonry and brick work;
- Graffiti (removal/repainting);
- Plumbing systems;
- Safety issues (e.g. trip hazards);
- Security fences/signage;
- Vermin proofing; and
- Doors.

Cleaning of zone substation buildings shall be performed at regular intervals. The scope shall include grass-mowing, removal of unwanted vegetation, cleaning, sweeping and vacuuming of indoor substations.

Drainage systems and fall arrests on buildings shall be inspected and maintained annually. Inspection of the fall arrest systems shall be undertaken to ensure they are compliant with the relevant standards. Any repairs necessary to fences and gates would be identified and reported to JEN contract officers, who would negotiate with the responsible site owner and inform the contractor of any works that he should undertake.

1.12.4.5 *Asset Replacement/Disposal*

The replacement or major refurbishment of zone substation buildings will most likely be triggered by the need to replace protection and control equipment, not by the age of the buildings alone. Whereas security fences with be replaced when the condition of posts and/or panels are beyond economical repair.

In circumstances where indoor switchgear is replaced using the new modular building standard, the old buildings may be repurposed. This will be the case for the FW switchgear replacement project. The existing brick building will be repurposed as a spare equipment storage area. The building will need some remediation work to refurbish certain areas as documented in the dilapidation report.

Similarly in the past, part of the old HB switchroom has previously been repurposed as an emergency control room.

As identified in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

Table 4-63 lists the forecast capital expenditure replacement volumes for Buildings and Grounds of Zone substations to 2031, based on these drivers.

Table 4-63: Forecast Replacement Volumes - Zone Substations Buildings and Grounds

Replacement Volumes – Grounds/Domestic Management of Zone Substations		Year							
	Unit	2024	2025	2026	2027	2028	2029	2030	2031
Install Humeceptor for oil containment - Zone substations	ea	-	-	1	-	-	-	-	-
New modular switch room buildings - AW	ea	-	-	-	-	4	-	-	-
New modular switch room buildings - BD	ea	-	-	4	-	-	-	-	-
Humeceptor/Filtrelec – BY (2033)	ea	-	-	-	-	-	-	-	-
New modular control room and switch room buildings- CN	ea	-	4	-	-	-	-	-	-
Humeceptor/Filtrelec – CS	ea	-	1	-	-	-	-	-	-
New No.4 6.6kV modular switchroom - FF	ea	1	-	-	-	-	-	-	-
New modular control room and switch room buildings - FW	ea	2	-	-	-	-	-	-	-

Replacement Volumes – Grounds/Domestic Management of Zone Substations		Year							
	Unit	2024	2025	2026	2027	2028	2029	2030	2031
No.1 transformer and enclosure roof retirement – HB (Transformer is currently being replaced)	ea	1	-	-	-	-	-	-	-
ZSS property minor CAPEX works	ea	1	1	1	1	1	1	1	1

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how JEN prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-64 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure.

Table 4-64: Specific Drivers - Zone substation Buildings and Grounds

Driver	Risk/Opportunity Description	Consequence
Asset integrity, safety, health and environment	Flashover and fire risk due to vermin/flora/fauna Impeded substation access	Risk to employee safety and asset integrity
Asset integrity, safety, health and environment	Mal-operation of plant due to leaking roof	Risk to employee safety and asset integrity

The volumes of work required and associated capital and operational expenditure ensure that the consequences identified in the table above are addressed to maintain network performance and manage risks. This approach is prudent and efficient and ensures that the long term interests of customers are maintained.

Many of the older buildings contain asbestos or are asbestos clad and these need to be managed and disposed in accordance with EPA guidelines.

1.12.4.6 *Future Improvements*

A security review of all JEN Zone Substations was conducted in 2017 and a Zone Substation Security Strategy was prepared shortly thereafter. Specific recommendations have been made to improve security and reduce risks. These are:

- Access Control

  Install a standardised electronic access control system on all external gates and internal doors on all Zone Substations. Access should only be granted to those sites and assets which personnel are required to work on and not common across the network unless required. The system should be managed via the existing JEN security access card processes and procedures. I.e. Access applications to be made via the intranet and approved by relevant personnel.

- Site Lighting

  Install motion-sensor, timed or remotely activated floodlights to cover the entrance area and main external areas of all sites.

- Security Monitoring

  Install CCTV systems with on-board analytics capability and a real-time feed between all JEN Zone Substations and a nominated control room (outsourced or in-house). Additionally, consider implementing response plans involving either a contract security provider or local police to attend if intrusion into a JEN site is detected.

  Trial installation of the security improvements are to be actioned in 2025 at targeted zone substations.

- Transformer Oil Containment

  A trial installation of a water filter ([redacted]) to prevent petrochemicals(Transformer oil) oil loss into the environment has been trialled and installed at NEL and HB. These installations will be monitored for performance during seasonal changes.

- Modular buildings

  A new modular building design has been prepared to standardise on one HV switchroom design and one control room design. This will deliver repeatable building modules which are built off site, reducing exposure to people working in HV environments and significantly avoid repeated design costs.

- Arc Fault Venting Metal clad Switchgear External to Buildings

  In support of this initiative the Electricity Safety Act requires a major electricity company (JEN Electricity Network) must design, construct, operate, maintain and decommission its supply network to minimise, as far as practicable. By venting all new metal clad switchgear externally to buildings provides an opportunity for JEN to remove the risk of a person being exposed to gas (the composition of the vented gas is unknown) that is, under the current design, vented into the Switch Room. Once the design has been finalised, all AMS requirements will be prepared, and further expanded in this document. A Field Technical Change (FTC) process is required to be prepared and the primary design standard updated. Monitoring of water entry into the arc vents must be monitored to prevent catastrophic failure.

- It is recommend to reassess the RCM analysis conducted back in 2000 to now follow the IEC 60300 0-3-11,12 and 14 RCM guidelines, and quantitatively determine the maintenance intervals for all sub-asset classes.

- The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

1.12.5 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information requirement to achieve JEN's business objectives at the Asset Class level. ACS provide the context for and determine the information required to manage and operate an Asset Class.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives Table 4-65. *The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-66 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class.

Table 4-67 provides the information initiatives required to provide the future information requirements identified in Building and Grounds Business Objectives and Information Requirements *The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-66 contains the risk to the Sub-Asset Class from not completing the initiative.

All of the information required by the building and ground Sub-Asset Class is available within JEN's current business systems.

Table 4-65: Building and Grounds Business Objectives and Information Requirements

Business Objective	JEN Information Sources	Externally Sourced Data
Maintain safety, security, and structural integrity of Buildings and Grounds	SAP DrawBridge Condition/maintenance reports Daily situation reports	VESI primary plant committee* Alerts – from DB's and Government Organisations and manufacturers Manufacturing manuals AS/IEC standards

*The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-66: Building and Grounds Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Building and Grounds - Asset Creation	• Specifications requirements are located in the primary plant design manual • Zone Substation Primary Design Standard • New asset project progress reporting. Completion recorded in SAP • Asset register in SAP		• High – Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of Buildings and Grounds via inspections and audits	Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name	• Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	• Address • SAP Maintenance Reports • Performance history - Daily situation reports - Investigation reports (ECMS) - Plant defect reports • DrawBridge - Single line diagrams - plant data - OEM manuals - design drawings/layouts • SMI's – (Standard maintenance instruction) located on JEN's Intranet • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP		
Maintain functionality of Buildings and Grounds via Preventive Maintenance	• Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. • Scheduled task description, timing and completion recorded in SAP; SMIs held in SharePoint, Policies & Forms • SAP notifications and work orders activities performed and components replaced • Details of work completed recorded in SAP • OPEX & CAPEX cost reporting recorded in SAP	• Results are recorded in SAP and PM order scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply
Respond to Buildings and Grounds defects including security breaches. Perform corrective maintenance.	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name • Address	• Access all information via electronic tablet in the field. • All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.	• High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	• SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP • Performance history: - Daily situation reports - Investigation reports (ECMS) - Plant defect reports and maintenance reports • DrawBridge - Single line diagrams - plant data - OEM manuals - design drawings/layouts • Asset failure details and investigation reports. Stored in ECMS • OPEX & CAPEX cost reporting recorded in SAP		
ACS Review	• Condition data • Fault/failure data • Maintenance & replacement costs • AMS		• Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-67: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Access all information via electronic tablet in the field Update asset data in SAP for missing or incorrect data	To improve analysis and decision making Asset data available from business systems saving on site trips	Poor efficiency in accessing asset data	Asset data as per SAP requirements

1.13 ZONE SUBSTATION EARTHING SYSTEMS

1.13.1 INTRODUCTION

The Earthing Systems Asset Sub-Class Strategy applies to earthing systems installed in Zone Substations.

The Earthing Systems ACS provides an asset overview and identifies the most appropriate strategies and plans for managing assets over their lifecycles.

The ACS is based on key information about each asset including risk, performance, capital expenditure and operational expenditure. Based on this information, the Asset Class Strategy provides details about the JEN's earthing systems asset class strategies for the next five years, and comprises five key areas:

- Asset class profile includes information about the type, specifications, life expectancy and age profile of earthing systems in service across the JEN.
- Asset strategy outlines earthing systems asset management practices. This includes key earthing systems strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and programs of work. See Section 4.7.4 Life Cycle Management.
- Asset risk includes information about asset risk, including causes and consequences. See Section 4.7.2 Risk.
- Asset performance provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with earthing system management. See Section 4.7.3 Performance.
- Asset expenditure assessment provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

The ACS for Earthing Systems is intended to ensure the ongoing performance of the JEN and to mitigate network risks associated with the safety performance of earthing systems. Earthing and electrical protection systems must safely manage abnormal supply network conditions to avoid risk to people, or damage to property.

In the past, distribution substations were installed with separate HV and LV earthing systems. Common industry practice today is to combine the HV earth system with the LV Multiple Earthed Neutral (**MEN**) system, to form a Common Multiple Earthed Neutral (**CMEN**) system. JEN's practice is now to take this one step further and combine the zone substation earth grids to the CMEN system. The connection point of the zone substation earth grid and the CMEN usually can be seen at a cable head pole, and the metal clad switchgear CT chamber, and is referred to as the ZCMEN (Z = zone substation in this case).

The principle of establishing a CMEN system is to reduce the hazard presented by conductive HV structures by extending the HV earthing system beyond the locally earthed HV structure (e.g.. distribution substation, cable head, switch, concrete pole) and utilising the low voltage MEN network to contribute to a lower impedance path to earth. This is implemented in conjunction with the deployment of a Neutral Earth Resistor (**NER**) at zone substations to reduce the magnitude of earth fault currents so that the safety criteria for CMEN systems can be met. Thus, the CMEN system is a very efficient way of utilising the extensive LV MEN network to ensure compliance with step and touch voltages arising from HV to ground faults.

This excludes 66kV earthing systems, which are not covered by CMEN schemes.

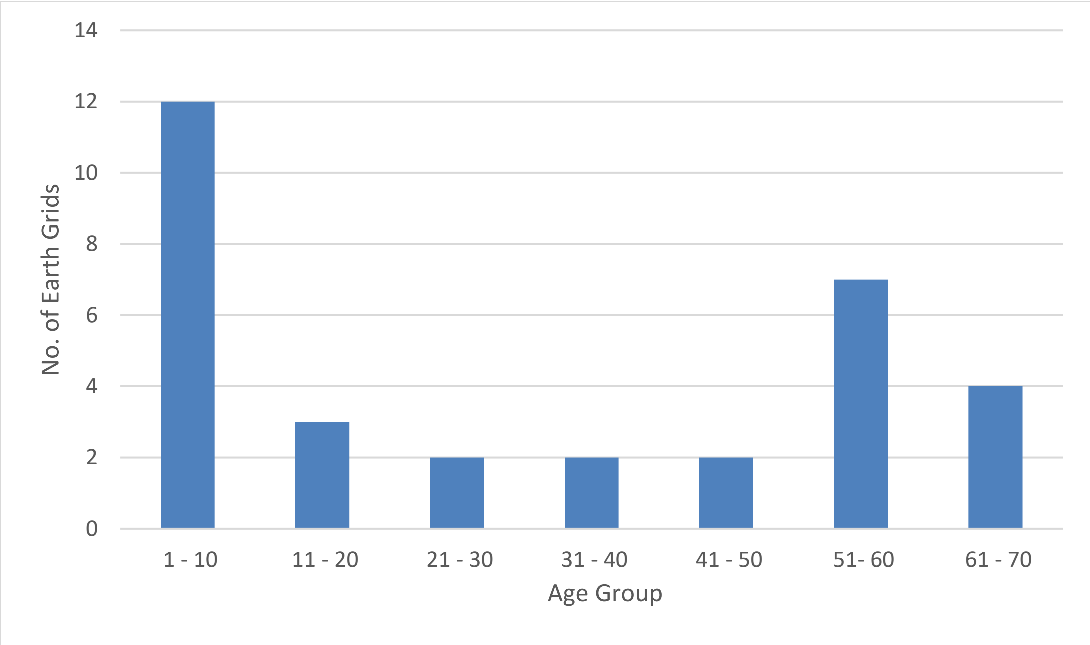
1.13.1.1 *Asset Specification*

Earthing systems must be made of corrosion resistant, high conductivity materials, specifically manufactured for the earthing of electrical installations. These materials include copper, copper alloy, aluminium, and stainless steel.

All metal and concrete structures located within 2.4 metres of the ground that support high voltage conductors and can be made alive in the event of primary insulation failure must be effectively earthed.

Figure 4–26 shows the current zone substation earth grid age profile.

Figure 4–26: Zone Substations Earth Grids Age Profile (Dec 2024)



The age of zone substation earth grids is similar to the age of zone substation buildings as the earth grid and building is established at the same time.

1.13.2 RISK

This chapter includes information about earthing system risk profiles involving the way that asset class criticality is established, the risks posed by earthing failure (including the various failure types and their possible consequences), other measures being introduced to manage asset risk, and a list of the various issues currently confronting earthing systems.

This information specifically involves:

- Asset class criticality score (sub-asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Existing controls;
- Asset Spares;
- Contingency; and

- Future risks (involving other potential risk issues currently being managed).

The strategy for the maintenance of earthing systems through periodic inspections and tests is driven principally by:

- A duty of care requirement for the safety of our personnel and members of the public;
- A requirement for the business to comply with the JEN ESMS; and
- The need for correct and effective operation of network protection systems in the event of an earth fault, by ensuring there is sufficient fault current.

Although it rarely occurs, there is the potential for an earth voltage rise to cause injury or death to staff, contractors or members of the public. This could occur if the safety performance of the earthing system fails to meet standards and is non-compliant.

Non-compliance with the Electricity Safety (Management) Regulations 2009 will lead to general regulatory queries from the technical regulator, Energy Safe Victoria.

Failure of earthing systems can also cause damage to equipment if protection systems are unable to operate in the manner in which the system was designed.

Emerging risks include:

- Ageing installations with likely deterioration of earth grids; and
- Changes to network fault levels requiring enhanced earth grids.

1.13.2.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is used to rank the importance of dissimilar sub-asset classes (e.g. transformers and buildings and grounds) to identify areas where risk should be managed first and control measures implemented.

The earthing systems has an asset criticality score of AC4 (High) due to the health and safety consequences associated with failures.

Classification: High Criticality

Inability to detect earth faults preventing the operation of HV protection systems.

There is health and safety risk to staff and the general public caused by step and touch potentials.

1.13.2.2 *Spares*

It was determined that earthing conductors and connection materials are available from stock, including CMEN and ZCMEN labels, are constructed of commercially available hardware and equipment; therefore any required material can be purchased from suppliers. Earthing system components are stocked in the stores and replenished as required. Spares requirements for critical assets using the Critical Spares Assessment Procedure (ELE-999-PR-RM-002) is not relevant in this case.

1.13.2.3 *Failure Modes*

Likely failure modes for substation earthing systems include:

- Corrosion of buried earth grid conductors – can result in high resistance or open circuit;
- Physical damage to or missing structure to earth grid connections;
- High resistivity soil – can result in high resistance between soil and buried conductors; and
- High resistance joints between earth grid conductors and between grid and connections to above ground structures.

1.13.2.4 *Existing Controls*

Existing controls are essentially those detailed in the recommended asset operations and maintenance tasks documented in section 4.7.4.4, together with initiation of augmentation projects for assets determined to not comply with EPR limits determined by testing.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the assets. Once determined, repairs can be actioned utilising materials in stock.

1.13.3 PERFORMANCE FACTORS

The primary objective of employing earthing systems is to maintain effective earthing systems associated with zone substations to ensure safety to personnel and public.

SAP records of substation earthing system defects and repairs are available and there is no significant increase in defects and repairs over previous years.

1.13.3.1 *Requirements*

There is a regulatory requirement to verify the earthing system for zone substations at least once every 10 years. In the event that the earthing system at a particular location does not meet the minimum requirements, the existing earthing system is assessed, possibly redesigned, and augmented as necessary to reduce the impedance to acceptable levels.

In 2013, there has been a major change in the earthing system methodology for zone substations. Zone substation earthing system design has previously been based on the legacy design standards established by the SECV where, there is a separation and isolation of the zone substation earth grid from the external distribution network earthing system and from any conducting structure or mediums that would facilitate the transfer of any hazardous potential rise that occurs on the zone substation earth grid to surrounding infrastructure. A program has been initiated such that the zone substation feeder exit cables are bonded to the CMEN system, effectively extending the zone substation earth grids to the CMEN area. This methodology is detailed in ST-PPDS-2013-087 JEN Strategic Planning Paper – Earthing Systems. The point of connection between the ZSS earth grid and the distribution network CMEN is labelled ZCMEN.

Earth grids and earth connections installed in zone substations are expected to have the same life as the substation, that is in excess of 50 years.

1.13.3.2 *Assessment*

A number of factors are assessed to determine if earthing systems have a high reliability that they will continue to perform reliably its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and actual performance are analysed and examined. The following reports provide data for these areas.

SAP records of zone substation earth systems defect and repairs. When we issue an order to undertake defect/repair work, this will be recorded in SAP PM order. The SAP notification (if raised) will record the cause code.

Common issues found during earth grid testing include inadvertent bonding of the zone substation earth grid to the CMEN system, corroded earth grid connections, connections that have not been welded, step and touch issues in and around the zone substation including at neighbouring properties. A project to bond the zone substation earth grids to the CMEN system was initiated in 2015. Majority of JEN's electricity zone subs have been successfully bonded to the CMEN and this has resulted in a very low earthing system impedance at the zone substation. This makes the substations very safe and results in cost savings of thousands of dollars to carry out remediation work.

A review of the adequacy of zone substation earthing with respect to AS2067 is being undertaken. Findings will be addressed according to the risk profile.

At EPN, the CMEN links to the zone substation earth grid had to be disconnected as there weren't enough feeders coming out of EPN. In 2024/2025 when EP gets decommissioned, there will be more feeders commissioned at EPN. The zone substation to CMEN bonds will then be re-established to ensure we get a minimum of 4 feeders connected.

The utilisation of earthing systems is considered to be high as they are continuously in service.

Controls employed (inspection, condition monitoring & maintenance) and condition based replacements completed are identified below. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table:

Table 4-68: Controls effectiveness

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Earthing systems failure – people safety and or environment impact	Asset Management strategy applied. Earth grid tested and mitigation work implemented. Except for EP Replacement projects completed	Nil
Regulatory & compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

1.13.4 LIFE CYCLE MANAGEMENT

This chapter includes information about earthing system asset management practices, including key earthing strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- Asset lifecycle management options;

- Asset creation (including asset acquisition and asset spares);
- Asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- Asset disposal; and
- Future improvements.

1.13.4.1 *Lifecycle management options*

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure

The lifecycle management options for earthing systems are:

- Condition Based Replacement or Refurbishment;
- Proactive Replacement Programs based on age; and
- Run to Failure.

Condition based replacement or refurbishment is the preferred lifecycle management option.

Replacement or augmentation of earthing system equipment is typically required when periodic inspection and testing or notification of an incident, reveals degradation of that system. Degradation can take the form of conductor and connector corrosion, mechanical fatigue, vandalism or inadvertent damage due to excavation.

Earthing system augmentation is undertaken when step touch and transfer potentials are identified as exceeding the maximum safe limits.

There is no proactive replacement of earthing systems, as condition based monitoring in the form of inspection and testing are relatively inexpensive and focuses on issues identified. Moreover, periodic inspection of earthing systems is a regulatory requirement.

Periodic inspection and testing of earthing systems is a JEN internal technical standard and the run-to-failure management option cannot be applied as this would not comply with the Electrical Safety (Management) Regulations 2009.

1.13.4.2 *Regulations and Standards*

The Electricity Safety (Management) Regulations 2009 prescribes that JEN will comply with its internal technical standards. JEN internal standards reflect the Electricity Safety (Network Assets) Regulations 1999 to which the JEN assets have been designed, constructed and maintained. JEN has conducted a Formal Safety Assessment as part of its Electricity Safety Management Scheme (**ESMS**) submission to Energy Safe Victoria (**ESV**) which incorporated a risk assessment of the adequacy of JEN's current internal technical standards, in particular the requirement for inspection and testing of earthing systems in zone substations and non CMEN areas within 10 years. ESV has reviewed and approved JEN's ESMS.

1.13.4.3 *Creation*

Earthing systems are initially installed as part of new installations of zone substation assets.

These earthing systems may be expanded if condition based monitoring dictates or if augmentation projects occur at a substation.

1.13.4.4 *Asset Operation and Maintenance*

This section provides information about the current asset maintenance program.

The current asset maintenance program involves:

- Condition based monitoring in the form of inspection and testing; and
- Reactive and corrective maintenance

At 10-year intervals the following shall be undertaken to ensure earth grids continue to comply with safety criteria:

- Sample inspections of underground conductors & conductor joints shall be conducted to check for any corrosion or damage. As part of this check, a “transfer hazard check” shall be conducted to ensure no new underground pipelines, metallic communications cables, and unauthorised connections have been made to the perimeter fence.
- A grid continuity test shall be conducted. This test can use portable instruments and measure between a main earth grid reference connection and each structure earthing point. This is particularly important for high energy dissipation points such as surge arrester, portable earth, and earthing switch earth connection points.
- An annual inspection shall be undertaken of all above ground structure earth to earth grid connections for all HV and LV equipment.

The following inspection requirements are to be adhered to for Earthing Systems:

- Check that earthing and bonding connections to equipment such as transformers, switchgear, cable sheaths, support framework, cubicles etc. are intact;
- Inspect flexible bonding braids for fracture or corrosion during maintenance and switching operation;
- Inspect main earth conductor above ground for signs of damage;
- Inspection of the ZMEN connection as part of the pole and line inspection program;
- Check the condition of any crushed rock inside the substation for thickness and cleanliness. If the rock layer is filled with soil or grit its insulating properties may be compromised; and
- Verify all neutral earth connections are intact.

Reactive and corrective maintenance is undertaken on earthing systems when inspection and testing activities have revealed that the system is damaged or degraded, or when a notification is received that an incident has damaged the earthing system (e.g. earths damaged by an excavator, copper theft).

1.13.4.5 *Asset Augmentation and Replacement*

As identified in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

A notional budget may be required to improve the performance of earth grids to maintain employee, contractor and the public safety, due to dangerous step, touch or transfer voltages. Non-compliance also exposes JEN to the risk of litigation due to injury or non-compliance penalties.

Table 4-69 lists the forecast capital expenditure augmentation volumes for earthing systems from 2024 to 2031.

Table 4-69: Notional Forecast Upgrade Volumes - Zone Substation Earthing Systems

Augmentation Volumes – Earthing Systems		Year							
	Unit	2024	2025	2026	2027	2028	2029	2030	2031
Upgrade zone substation earth grids	ea	-	1	-	1	-	1	-	-

A capital project prioritisation process is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how JEN prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-70 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure

Table 4-70: Specific Drivers - Zone Substation Earthing Systems

Driver	Risk/Opportunity Description	Consequence
Environment, safety and health	Earth potential rise	This poses a risk to the public and employees and is something that needs to be actively managed on an ongoing basis, to ensure that changes in short circuit levels are managed appropriately.
Asset integrity	Issues with theft of copper	On an annual basis, theft of copper (earthing) raises integrity issues for earthing systems that need to be managed on an ongoing basis.

The volumes of work required and associated capital and operational expenditure ensure that the consequences identified in the table above are addressed to maintain network performance and manage risks. It is a prudent approach and ensures that the long term interests of customers are maintained.

1.13.4.6 *Disposal*

Earthing systems are typically not removed from service, however should disposal be required; it is scraped according to the scrap material policy. Refer to JEM PO 1066 – Scrap Materials Policy for details.

1.13.4.7 *Future Improvements*

- Future improvement to the management of earthing systems will be to complete the CMEN distribution network earthing system program and the implementation of the ASC/REFCL system for resonant earthing at all high exposure bushfire zone substations. In addition, JEN plans to further install ASC/REFCL systems similar to the unit installed at ZSS SHM to enhance public safety. This is a JEN lead initiative with the next installation planned for ZSS FW. ASC installations will improve public safety and reduce the likelihood and consequence of arc flash exposure to JEN and Zinfra employees. The likelihood of a single phase fault developing into a 3 phase fault will be better controlled by an ASC, and minimised. It is envisaged that all JEN ZSS sites will ultimately be installed with resonant earthing.
- Decommissioning of EP will take place in the short term, as an NER does not exist for the 6.6kV distribution voltage.

- It is recommend to reassess the RCM analysis conducted back in 2000 to now follow the IEC 60300 0-3-11,12 and 14 RCM guidelines, and quantitatively determine the maintenance intervals for all sub-asset classes.
- The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

1.13.5 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information requirement to achieve JEN's business objectives at the Asset Class level. The ACS provide the context for and determine the information required to manage and operate an Asset Class.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives (Table 4-71). *The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-72 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class. Table 4-73 provides the information initiatives required to provide the future information requirements identified in Table 4-72. Included within Table 4-73 is the risk to the Sub-Asset Class from not completing the initiative.

All of the information required by the transformer Sub-Asset Class is available within JEN's current business systems.

Table 4-71: Earthing System Business Objectives and Information Requirements

Business Objective	JEN Information Sources	Externally Sourced Data
Maintain safety, availability and reliability of Earthing Systems	SAP DrawBridge Condition/maintenance reports Daily situation reports	VESI primary plant committee* Alerts – from DB's and Government Organisations and manufacturers Manufacturing manuals AS/IEC standards

*The Victorian Electricity Supply Industry (VESI) Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

Table 4-72: Earthing System Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Earthing System - Asset Creation	• Zone Substation Primary Design Standard • New asset project progress reporting. Completion recorded in SAP • Asset register in SAP		• High – Regulated to maintain supply reliability, safety and quality of supply.
Maintain functionality of Earthing Systems via inspections and audits	Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name • Address • SAP Maintenance Reports • Performance history - Daily situation reports - Investigation reports (ECMS) - Plant defect reports • DrawBridge - Single line diagrams - plant data - OEM manuals - design drawings/layouts • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP	• Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply
Maintain functionality of Earthing Systems via regulatory testing requirement (10 yearly interval)	• Regulatory testing tasks, schedules and progress in SAP • Scheduled task description, timing and completion recorded in SAP; Policies & Forms • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP • OPEX & CAPEX cost reporting recorded in SAP • Test reports • Fault current level calculation outputs	• Results are recorded in SAP scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. All documents to be scanned and stored in Drawbridge. • Access all information via electronic tablet in the field. • Update asset data in SAP for missing or incorrect data.	• High – Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	• Published Distribution Annual Planning Report available on JEN website		
Respond to Earthing System defects / faults to restore equipment operationally. Perform corrective maintenance.	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name • Address • SAP notifications and work orders activities performed and components replaced. • Details of work completed recorded in SAP • Performance history: - Daily situation reports - Investigation reports (ECMS) - Plant defect reports and maintenance reports • DrawBridge - Single line diagrams - plant data - OEM manuals - design drawings/layouts • Asset failure details and investigation reports. Stored in ECMS • OPEX & CAPEX cost reporting recorded in SAP	• Access all information via electronic tablet in the field. • All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.	• High: Regulated to maintain supply reliability, safety and quality of supply
ACS Review	• Condition data • Fault/failure data • Maintenance & replacement costs • AMS		• Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-73: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Access all information via electronic tablet in the field Update asset data in SAP for missing or incorrect data	To improve analysis and decision making Asset data available from business systems saving on site trips	Poor efficiency in accessing asset data	Asset data as per RCM and SAP requirements

5. CONSOLIDATED PLAN

1.13.6 ASSET INVESTMENT PLAN

The Asset Investment Plan (AIP) provides a snapshot of how JEN will be managed to achieve its Asset Management Plan (AMP) objectives and consequently JEN's strategic objectives. It also outlines the key asset strategies supporting JEN's goals and objectives and informs the proposed expenditure plans and programs of work. The purpose of the AIP is to:

- Detail the investment plan for the next seven years for the capital and operating expenditure programs of work including the drivers for expenditure, current issues and the strategies for managing current issues; and
- Outline the current and emerging financial risks and opportunities impacting on JEN and describe how JEN is positioned to mitigate or take advantage of the identified risks and opportunities.

The AIP defines the nature of the works to take place to manage JEN within the constraints of cost and risk whilst at the same time maintaining current levels of network reliability and safety. A high level view of program deliverables is provided that encompasses the major projects to be delivered to ensure supply security for our customers is maintained.

It also contains the rationale for asset management activities, operational and maintenance plans and capital investment (overhaul, renewal, replacement and enhancement) plans.

1.13.7 CAPITAL AND OPERATIONAL WORK PLAN

The Capital and Operational Work Plan (COWP) contains details on optimised capital and operational expenditures over a two year period. It aggregates the required actions emanating from the JEN AMP and maintains a line of sight through to the JEN Business Plan via the AMP as well as various ACSs.

The COWP aids development of the JEN Delivery Plan, the purpose of which is for Service Providers to critically evaluate field resource availability with the program of work required to be delivered. Refer to Figure 1–2 for the JEN AMS which identifies where the COWP is positioned within the AMS document hierarchy.

6. GLOSSARY

1.14 ZONE SUBSTATION ABBREVIATIONS

Substation	Suburb	Substation	Suburb
AW	Airport West	MAT	Melbourne Airport
BD	Broadmeadows	NEI	Nilsen Electrical Industries
BMS	Broadmeadows South	NEL	North East Link
BY	Braybrook	NH	North Heidelberg
CBN	Craigieburn North	NS	North Essendon
CN	Coburg Nth	NT	Newport
COO	Coolaroo	PTN	Preston
CS	Coburg South	PV	Pascoe Vale
EPA	East Preston A	SBY	Sunbury
EPB	East Preston B	SHM	Sydenham
EPN	East Preston	SSS	Somerton Switching Station
ES	Essendon	ST	Somerton
FE	Footscray East	TH	Tottenham
FF	Fairfield	TMA	Tullamarine Airport
FT	Flemington	VCO	Visy Board
FW	Footscray West	YVE	Yarraville
HB	Heidelberg		

7. APPENDICES

1.15 APPENDIX A – PREVENTIVE MAINTENANCE CLASS FOR TRANSFORMERS

There are five classes of preventive maintenance.

Class 1

This class requires the overhaul of the OLTC mechanism based on the number of operations or time since the previous overhaul (every two to six years, depending on type). In areas where transformers are subjected to high humidity and heavy pollution, the overhaul period may be reassessed.

Overhaul includes greasing and lubrication, cleaning and checking of mechanical and electrical switches, checking the integrity of weatherproof seals, and a functional test of mechanical drives.

Class 2

This class requires a combined mechanism and diverter switch overhaul every six years or sooner if required by operating duty. If the history of the tap-changer indicates more regular inspection is required, the period of overhaul can be varied.

Overhaul requires checking diverter contact wear, connection tightness, inspection for sign of insulation failure, oil filtering, and a functional test of tap-changer drives.

Class 3

This class requires overhaul of the OLTC tap-selector. In a combined diverter/selector switch, the overhaul is carried out at the same time as the Class 2 maintenance. If the tap-selector is located in a separate compartment to the diverter switch and is therefore free of contamination by arcing residues in oil, then the condition of the selector switch is monitored annually via a DGA.

Class 4

This class includes a combination of Class 2 maintenance and an overhaul of the transformer's exterior (with a minimum to maximum maintenance interval of 4 to 6 years, respectively).

Overhaul work includes: main tank and radiator oil leak repairs via either tightening bolts or replacing gaskets; bushings, surge arresters, and neutral isolator cleaning; instrument and forced cooling checks; painting; and surge arrester insulation resistance checks.

Class 5

This class requires a workshop transformer overhaul. A major repair/refurbishment task, this class is only conducted when an internal core or winding fault is detected, or when the unit is to be upgraded to supply a higher load.

Typical works may include rewinding, a complete transformer dry-out, overhaul of bushings and tap-changers, gasket replacement, oil leak repairs, and painting.

1.15.1 MAJOR REPAIRS

Refurbishment

Refurbishment of aged zone substation transformers is labour-intensive and involves de-tanking the transformer and installing new windings, which is generally not economically viable when compared to replacement.

This class types viability is questionable to cost and replacement should be considered as an alternative.

Major transformer repair normally occurs in a workshop and is generally only required if the:

- transformer has developed an internal core or winding fault, or
- major paper insulation system is seriously degraded by moisture, affecting the transformer's reliability and life expectancy.

A major repair may also be performed when a transformer is being upgraded to carry a higher load, which typically includes internal work and external work.

Internal work involves:

- removing the core and coil assembly from the tank and checking tapping leads and connections and their associated supports;
- checking internal insulation for damage and defects;
- checking winding blocks and coil clamping;
- flushing the core and coil assembly and cooling ducts with insulating oil; and
- checking the insulation of all accessible core bolts and between the core and the core frame.

External work involves:

- replacing the tank lid, bushings and valve gaskets;
- overhauling the radiators, valves, conservators, oil gauges, and tap-changer drives; and
- filtering and reconditioning the insulating oil.

1.16 APPENDIX B – CONDITION-BASED MONITORING

1.16.1 CONDITION-BASED MONITORING

Component-specific condition-based monitoring involves the following transformer and zone substation components and equipment:

- oil sampling and testing;
- dissolved gas analysis;
- degree of polymerisation value;
- infra-red thermal imaging;
- high voltage bushing monitoring;
- tap-changers;
- winding temperature indicators;
- station service transformers; and
- NERs

1.16.2 OIL SAMPLING AND TESTING

Annual oil tests conducted to provide information about a power transformer's condition include:

- dissolved gas analysis;

- dielectric strength;
- acidity;
- water content;
- Inhibitor content;
- interfacial tension; and
- oil particle counts.

1.16.3 DISSOLVED GAS ANALYSIS

Transformer core and coils

Transformer oil DGA is conducted at least once a year and is more widely used to diagnose incipient faults or defects before they develop into major problems. The technique can also be used after a fault has occurred to assist with the diagnosis of the failure cause.

A DGA test, which measures the internal health of the core and windings:

- determines the volume and ratio of gases such as hydrogen, methane, ethylene, ethane, acetylene and carbon oxide dissolved in the transformer oil; and
- indicates a developing internal transformer fault as well as providing more general information about transformer insulation system ageing (depending on the composition and the amount of gases collected).

Tap changers

Tap-changers can also be monitored via a DGA. To deal with high levels of gas developed during normal switching operations, a series of gas ratios and criteria to interpret the oil test results have been specifically developed for OLTCs.

In terms of maintenance and monitoring:

- With the move to new tap-changer designs that require minimal maintenance, the introduction of a non-intrusive and cost-effective condition-monitoring test is considered prudent; and
- Oil sampling for DGA analysis is recommended annually (facilitated by units with gate valves).

1.16.4 DEGREE OF POLYMERISATION VALUE

The principle measure of a transformer's life is the condition of its insulating paper. The insulating paper's degree of polymerisation (DP) value is an indicator of its condition, which can be obtained from paper samples. Table 7-1 summarises the relationship between the DP value and the condition of the insulating paper.

Table 7-1: Relationship between DP Value and Transformer Paper Insulation Condition

DP Value	State of Insulating Paper
1,200	Fresh paper
800 – 1,000	Dried-out paper in a new transformer
700	Initial value for a new transformer in service
200	End of reliable use as an insulating material in a transformer

In terms of a transformer's DP assessment, a DP value:

- of 200 means the transformer is at end-of-life and requires replacement; and
- below 200 means a transformer is unreliable.

Transformer winding insulation failures have occurred at DP levels of 300, and the risk of failure depends on the probability of a fault occurring close to a zone substation.

For more information about how DP values are established, see Appendix C.

1.16.5 INFRA-RED THERMAL IMAGING

Infra-red thermal imaging of transformers is carried out as a part of the annual thermal inspection program to identify external problems associated with poor connections or auxiliary equipment operating at abnormally high temperatures.

1.16.6 HIGH VOLTAGE BUSHING MONITORING

Transformer bushing failures have been recognised as a common point of transformer failure creating a hazard to people in the surrounding area as well as damage to the transformer. As a result, a bushing condition monitoring program has been implemented to measure the DDF of 66 kV transformer bushings.

Undertaken on a five-year cycle, the DDF test indicates the condition of the bushing's insulation and can reduce the risk of explosive failure.

The results of this bushing condition monitoring program will directly feed into the bushing replacement program, and provision has been made in the capital expenditure program for the replacement of bushings with deteriorated insulation and excessive moisture content.

Legacy bushing types

The old State Electricity Commission of Victoria (SECV) standardised the 66 kV bushings for all power transformers manufactured before the 1980s. These bushings:

- are a synthetic resin bonded paper (SRBP) type used widely in many zone substation transformers; and
- were purchased on period contracts and supplied to transformer manufacturers to be fitted to the transformers during assembly.

Moisture penetration and DDF testing

Moisture penetration can lead to electrical discharge and failure and often results in explosion. The probability of moisture ingress increases with age, making DDF measurements for moisture content important. The measurements are compared to the DLA Testing Tan Delta Result Card as per Figure 7–1.

Twenty-one bushing defects have been identified by the condition monitoring program. In one case the DDF testing has measured a leakage current above recommended values and consequently the bushing was replaced.

The failure mode of oil impregnated (OIP) bushings is significantly worse than the SRBP type. As a result, all future 66 kV bushing replacements will ideally be of a resin impregnated (RIP) silicon rubber housed type.

Figure 7–1: DLA Testing Tan Delta Result Card

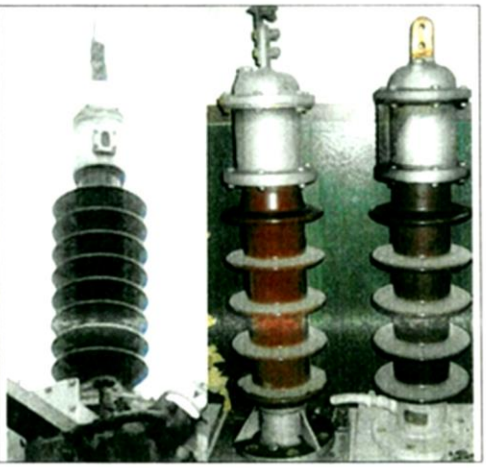
🟢	Pass	🟠	Bad Result – replace bushing soon	🔴	Fail – Bushing should not return to service

OIP Bushings (ABB GOB/GSA, after 1982)

Measured Result	Means...
Result > 0.7 %	🔴
Result <= 0.7 %	🟢
In frequency sweep, the maximum %PF is double the minimum %PF	🔴

RBP Bushings (all older types pre-1982, EE, MIC, etc)

Measured Result	Means...
C1 Result > 1.5 %	🔴
C2 Result > 5 %	🔴
C1 Result between 1% and 1.5%	🟠
C1 Result < 1 %	🟢
If any phase bushing C1 result is more than double another phase bushing C1 result	🟠
In frequency sweep, the maximum %PF > double the minimum %PF	🔴



1.16.7 TAP-CHANGERS

The number of tap-changer operations and their associated operating mechanisms varies on a daily basis, and their condition must be monitored and regular maintenance performed to ensure reliable operation.

Issues that can arise involve the following:

- High contact resistance inside tap-changers can result in overheating, resulting in transformer winding failure;
- Poor oil quality due to the accumulation of carbon particles can result in an internal flashover, which is expensive and requires several weeks to repair; and
- Mechanisms can develop mechanical defects leading to out-of-step (OOS) faults. Preventive maintenance has significantly improved the reliability of oil-immersed tap changers.

Common tap-changer fault types

The most common type of fault associated with tap changers is an OOS. This occurs when the voltage tap of one of the transformers in a bank is not synchronised with the others. When this occurs, the OOS relay trips the supply to the tap-changing control circuit to:

- reduce the risk of transformer overheating due to circulating currents; and

- prevent abnormal voltage excursions on the zone substation bus.

An OOS problem does not result in loss of customer supply, but it does require diagnosis from operating and test personnel to address the problem. One of the following faulty components generally causes OOS alarms:

- brake mechanisms;
- raise and lower contactors;
- OOS relays;
- voltage regulating relays;
- maintaining switches; and
- auxiliary switches.

A significant reduction in the incidence of OOS problems has been achieved via the regular refurbishment and replacement of aged and defective components

1.16.8 WINDING TEMPERATURE INDICATORS

Winding temperature indicators are devices that effectively model the transformer winding temperature. Winding temperature indicators also need to be as accurate as possibly, because they dictate transformer loading decisions, given the limits placed on a transformer's winding temperatures determine its overload capacity.

Specific winding temperature indicator issues include:

- Indicators fitted to transformers before the mid 1970's have up to a 15°C margin of error;
- The outputs from the indicators generate alarms via the SCADA system in the network control room; and
- Incorrect temperature indication can result in the transformers being over- or under loaded.

1.16.9 STATION SERVICE TRANSFORMERS

Station service transformers are visually inspected as part the monthly inspection regime and the annual engineering audit.

Station service isolating transformers are connected to the LV reticulation network. To ensure the reliability of station LV supplies, it is now standard practice to have two 22 kV/415 V station service transformers with an LV auto change-over scheme.

1.16.10 NEUTRAL EARTHING RESISTORS

NER maintenance occurs every four years. This involves a close inspection for defects such as cracked resistor welds and insulation contamination. Testing is limited to:

- contact resistance;
- NER total resistance; and
- insulation resistance measurements.

The insulator surfaces are also cleaned to avoid flashovers due to dust accumulating and combining with moisture in the air. Maintenance intervals will be adjusted due to environmental conditions as required.

1.16.11 RAPID EARTH FAULT CURRENT LIMITER (REFCL)

REFCL maintenance occurs every two years, to perform detailed inspections of the neutral reactor including functional testing of the reactor motor drive unit.

Annual engineering and monthly inspections by operators will also take place to identify defects such as cracked insulator, oil levels, oil leaks, operating temperatures, breather and reactor tank condition.

1.17 APPENDIX C – ESTIMATING TRANSFORMER DEGREE OF POLYMERISATION VALUES

A power transformer contains a significant amount of paper insulation and its condition varies. Deterioration is at its highest where temperatures are highest, and this occurs within the transformer windings, which is not accessible. As a result, where a transformer is in service the condition within the winding can only be estimated.

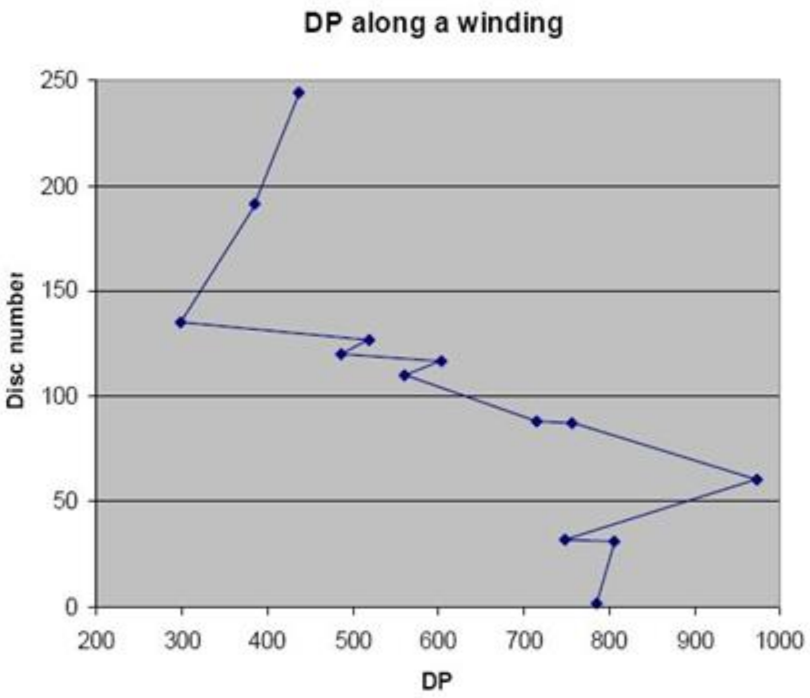
Diagnostic testing and historical data are the only means available to determine the condition of the transformer deep within the insulation structure without dismantling the unit.

Figure 7–2 shows the results from paper sample Degree of Polymerisation (DP) measurements taken from taken from different positions along the height of the winding of a dismantled transformer.

The DP value can vary significantly within a transformer:

- The hottest part of the transformer—the middle of the winding—exhibits the lowest DP value.
- The insulation at the base of the transformer remains cool for most of its life and typically suffers little degradation.

Figure 7–2: Degree of Polymerisation throughout a transformer winding



1.17.1 FURAN ANALYSIS

The DP can be assessed by either a:

- Furan analysis of the transformer oil, or
- direct paper sample measurements.

Furan analysis involves oil sample testing for the presence of the products of cellulose decay in a transformer. These tests can be undertaken routinely as part of the annual oil sample program and the DP values monitored and trended. However, the furan level should only be used as an indicator across a population to determine the transformers that have aged the most. Other testing is required to accurately determine the actual insulation condition of the transformers.

A direct paper sample is taken from a main transformer's windings and leads for DP testing whenever an opportunity arises.

1.17.2 COMPARISON OF DP ESTIMATION METHODS

JEN refurbished a number of transformers on the United Energy Distribution Network over the period between 2007 and 2010, and a large number of paper samples were taken. Table 7-2 shows a summary of the results and the different conditions within a power transformer.

Table 7-2: Summary of De-Tanked Transformer DP Values

Transformer[1,2]	DN #1	MTN #1	MTN #3	GW #3	MTN #2	RBD #1	RBD #3	Average
Average Lead	422	423	390	698	N/A	697	360	498
Average top winding	312	274	315	379	301	567	320	353
Furan-derived DP reading	613	645	661	636	683	677	645	651
Difference - lead and winding	111	148	75	319	N/A	130	40	137
Furan DP: winding DP ratio	1.97	2.35	2.10	1.68	2.27	1.19	2.02	1.94

1. Paper samples were collected from both the HV winding and the HV leads as these parts of the transformer structure are easily accessible.
2. Furan-derived DP readings were taken from 2007 DGA tests (earliest available).

Observations resulting from this testing include the following:

- On average, the estimated DP derived from furan levels is approximately twice that of the actual paper sample within the transformer winding;
- The average difference between the paper sample from the centre of the winding and the paper sample at the top of the winding (winding lead) is over 130DP;
- The lowest DP value of the insulation should be used as the overall condition measure of the transformer;
- Where the insulation is of the lowest strength will be the location with the highest likelihood of being the point of failure; and
- The insulation condition deep within the winding of an aged transformer is at least 100DP worse than the insulation at the top of the winding.

1.17.3 TRANSFORMER MOISTURE CONTENT BY PDC AND RVM

Polarisation and Depolarisation Current (PDC) and Recovery Voltage Measurements (RVM) are measurements of the dielectric response of a transformer's insulation system, which can be interpreted to give accurate transformer insulation system:

- moisture content assessments, and
- average DP value estimates.

A transformer's moisture content is a significant indicator of the transformer's condition and a major contributor to the rate of ageing of the paper insulation. PDC and RVM tests are an accurate measure of paper insulation condition and can be used to determine a transformer's end-of-life.

PDC and RVM testing is carried out so that in time all transformers are tested:

- once they reach the age of 45 years to assist with end-of-life prediction, and
- as required, to assist with the refinement of the retirement/replacement decision.

Test accuracy

The value of the test lies in the accuracy of the moisture assessment and in the close correlation achieved between the assessed average DP and the paper sampling result.

The test is more accurate than estimating the DP values from oil sample furan analysis, which tends to overestimate the actual value.

PDC and RVM testing is recommended to be scheduled to be performed on five transformers each year. Continue and further testing of the transformer will determined.

1.17.4 TRANSFORMER PAPER SAMPLES – ADDITIONAL INFORMATION

The ultimate determination of a transformer’s condition derives from remove a section of paper from the transformer winding for testing for its actual DP value, which is expensive and difficult to perform.

It is not possible to obtain paper samples from within the winding, which provide the true measure of the poorest DP condition. As a proxy, paper samples are taken from leads (end of the winding), which age at a lower rate and so are in a better condition than the winding.

Estimating winding condition from winding lead results

The data collected over the past decade has led to the development of the following rules, which are applied to the winding lead result and other non-invasive test results to estimate the condition within the winding:

- The DP value of the winding lead of an aged transformer is on average at least 100DP higher than the DP value in the winding. The DP value of the neutral lead of an aged transformer is at least 200DP higher than the DP value of the winding;
- Comparisons between the furan-derived DP and paper samples show that the figure (based on 2-FAL count) overestimates the condition of the transformer by approximately 300DP for an aged transformer; and
- The correlation between the results of PDC/RVM and furan-derived DP levels is that the PDC/RVM test result is around 250DP lower than the furan-derived DP level.

There are still margins of error within these tests, and it is not possible to determine the single worst DP value in the transformer to determine its exact timing without deconstructing the transformer. However, these estimates are likely to be conservative, and a true condition of a transformer may be worse than the condition assigned by applying these rules.

1.18 APPENDIX D – ASSET RISKS AND ISSUES

Other asset risks and issues apart from what has been already been covered in the ACS, include excessive noise, oil containment, Copper Sulphide corrosion and Polychlorinated biphenyl (PCB) contamination.

1.18.1 NOISE REDUCTION

Power transformers at zone substations create more noise at peak load periods and additional noise from cooling fan operation. While new zone substations are constructed so that noise is kept within allowable limits, older substations may not comply and noise attenuation measures may be required.

Non-complying zone substations

If a complaint is referred to the Environment Protection Agency (EPA) and a zone substation is found to be non-compliant, noise reduction works may be enforced.

New zone substation compliance

New zone substations will meet the requirements of the EPA regulations. Prior to construction, measurements of the background noise levels are taken and recorded. Noise limits are specified for major plant items to minimise noise levels (particularly transformers).

After construction and energisation, noise level measurements are taken for compliance. Generally, transformer noise containment enclosures or low noise transformers will be required where there is residential housing nearby.

1.18.2 OIL CONTAINMENT

Zone substation transformers typically contain 22,000 litres of insulating oil.

Action has been taken to reduce the risk of oil escaping, particularly through the construction of bunds for all power transformers.

A major escape of oil from a zone substation could result in significant clean-up costs and lead to prosecution by the EPA.

Oil leak prevention measures

While oil spill kits are stored at zone substations to address minor leaks, the effect of a spill can be minimised but not eliminated.

The preferred method to prevent further leakage into the ground includes:

- installing Humeceptor pits (or recommissioning the existing triple interceptor pits) which installing a [redacted] water filter to prevent the build-up of algae, and
- sealing the bunded areas around the transformers,

1.18.3 COPPER SULPHIDE

Table 7-3 lists the zone substations where transformer oil testing has identified potentially corrosive sulphur in the transformer oil. Further investigation into other transformer types (for example, instrument transformers) is required, and the phenomenon may affect other oil-filled HV plant. Monitoring of the annual DGA results for indicators of corrosive sulphur effect is necessary to prioritise further testing.

Table 7-3: Copper Sulphide Positive Transformers

Zone Substation	Transformer	Potentially Corrosive
Broadmeadows (BD)	No.4	Positive
Coolaroo (COO)	No.1	Positive
East Preston (EP)	No.2	Positive
Melbourne Airport (MAT)	No.1 and No.3	Positive
North Heidelberg (NH)	No.3	Positive
Sunbury (SBY)	No.1 and No.3	Positive

Copper Sulphide risk

The International Council on Large Electrical Systems (CIGRE) set up a working group in 2005 to investigate the formation of copper sulphide (Cu_2S) in transformer insulation. It is estimated that there have been 100 (large) unit failures from Cu_2S since the year 2000 around the world (except Japan).

Reaction process

It is believed the reaction is a two-stage process resulting in the following effects:

- Corrosive sulphurs react with bare copper to form complexes (containing copper and a disulphide);
- Reactive complexes decompose to form Copper Sulphide (Cu2S);
- Cu2S deposits form on conductors and paper insulation (Copper Sulphides are conductive and migration into the insulating medium can lead to localised electrical stress and heating); and
- Switching transients and impulses weaken the insulation, leading to failure.

The presence of sulphur does not mean the transformer will fail immediately, and enamelled copper is unaffected, however any insulation damage is irreversible.

Like most chemical reactions, heat increases the reaction rate. Oxygen is also necessary and is consumed during the reaction. DGA tests show a reduction (‘consumption’) of oxygen content and elevated levels of ethane and methane when copper sulphide is present.

Corrective action

Passivators have been added to all the affected JEN transformers to stop the reaction. Japan has been using passivated oils since the 1970s.

1.18.4 PCB CONTAMINATION

Polychlorinated biphenyls (PCBs) were used as an insulating liquid in electrical systems over a number of years, particularly in capacitors. PCBs represent an environmental risk and are carcinogenic. Before these risks were identified, some power transformer diverter switches and distribution transformers were contaminated with small quantities of PCBs.

Decontamination efforts

Significant effort has gone into the identification and removal where practical of all PCB contaminated transformer oil. Although no JEN transformer was PCB filled, some contamination was found, deriving from common oil handling equipment used during the manufacturing process and later for maintenance work.

Zone substation testing and identification

PCB contamination is categorised as:

- scheduled (greater than 50 parts per million, or
- non-scheduled (greater than 2 and less than 50 parts per million).

All power transformers and circuit breakers have now been tested for PCB contamination, with four transformers testing positive for low concentrations. A number of circuit breakers contain low levels of PCB and continue to be replaced with modern equivalents due to insulation condition.

All transformers, OLTC diverter switches and oil filled circuit breakers havebeen fitted with labels to identify the oil's PCB content, where a:

- green label identifies less than 2 parts per million;
- yellow label identifies greater than 2 and less than 50 parts per million; and
- red label identifies greater than 50 parts per million.

Handling procedures

Affected transformers have been affixed with warning signs. If internal oil work is required, special tankers will be used to ensure the PCB will not be transferred to other equipment. When the transformers are to be refurbished or if oil in the transformer main tanks is to be reconditioned, the oil will be managed in accordance with established procedures.

The Ferranti ES3 type tap changers also incorporated capacitors containing PCB in the tap-changer mechanism cubicle. In 1997, 35 ES3 tap changers were known to have these capacitors, fifteen of which leaked and contaminated the oil in the tap changer compartment. All capacitors in the tap changers were removed, the contaminated oils were replaced, and the residual PCB was assessed and found to be below the threshold level of contamination.

1.19 APPENDIX E – TRANSFORMER CONDITION HEALTH INDEX TABULATION

JEN Transformer Health Index

OUT OF DATE TESTS?

	PDC/RVM Test Results	PDC/RVM Test Results	Oil Test Results	Paper Sample	Test Date	PDC/RVM Test Results	Oil Test Results	Oil Test Results	Oil Test Results	Oil Test Results	Oil Test Results	Oil Test Results	Oil Test Results	Oil Test Results	Bushing TYPE	Bushing Type	OIP Bushing Test Results		
Legend	**PDC/RVM: DP Estimate (± 25)**	**Paper Moisture(%) (@25°C)**	**Furan: DP Estimate**	**Paper DP (Paper Sample)**	**Test Date**	**Oil Conductivity (S/m)**	**Transf. Oil Sample (°C)**	**Oil Quality**	**Moisture in Oil# (ppm)**	**Acidity in Oil# (mgKOH/g)**	**DGA**	**Dielectric**	**Inter Facial Tension (IFT)**	**Copper Sulphide (Cu2S)**			**C1% PF at 10kV R Ph**	**C1% PF at 10kV W Ph**	**C1% PF at 10kV B Ph**
Good	>400	<1%	>400	>400				Good	<20	<0.05	✓	>50	>30	No	OIP	RIP	0.7	<0.7	<0.7
															RBP		1	<1	<1
Test, Evaluate & Monitor	250-400	1% - 3%	250-400	300-400				Fair	20-30	0.05-0.15	?	30-50	20-30		OIP	RIP	-	-	-
															RBP		1.5	1-1.5	1-1.5
Initiate Life Extension Program	<250	>3%	<250	<300				Poor	>35	>0.15	X	<30	<20	Yes	OIP	RIP	0.7	>0.7	>0.7
															RBP		1.5	>1.5	>1.5

Transformer	ZSS	OEM	YOM	PDC/RVM Test Date	PDC/RVM: DP Estimate (± 25)	Paper Moisture(%) (@25°C)	Furan: DP Estimate	Paper DP (Paper Sample)	Sample Date (DGA)	Oil Conductivity (S/m)	Transf. Oil Sample Temperature (°C)	Oil Quality (Using PDC/RVM results)	Moisture in Oil# (ppm)	Acidity in Oil# (mgKOH/g)	DGA	Dielectric	Inter Facial Tension (IFT)	Copper Sulphide (Cu2S)	Bushing Make	C1% DF at 10kV R Ph	C1% DF at 10kV W Ph	C1% DF at 10kV B Ph	Bushing Test Date
No.1	AW	A.E.I.	1966	May-12	495	3.2	600	-	16/11/2022	2.89´10^{-12} (@25°C)	14	Good	16	0.06	✓	49	23	No	RIP	0.280	0.282	0.285	12/03/2020
No.2	AW	W.E.T.	1981	May-12	535	2.0	645	-	16/11/2022	2.07´10^{-12} (@25°C)	12	Good	13	0.03	✓	55	24	No	RBP	0.354	0.367	0.347	29/01/2020
No.3	AW	A.E.I.	1966	May-11	480	3.2	558	-	16/11/2022	3.47´10^{-12} (@25°C)	17	Good	16	0.12	✓	54	18	No	RIP	0.306	0.309	0.310	29/01/2020
No.4	AW	W.E.T.	1988	06.06.18	600.0	0.8	694	-	16/11/2022	1.25´10^{-12} (@25°C)	21	Good	8	0.01	✓	68	34	No	OIP	0.638	0.625	0.625	3/06/2020
No.1	BD	E.E.	1973	1/05/2010	530	1.3	541	284	23/11/2022	1.66´10^{-12} (@25°C)	45	Good	11	0.02	✓	49	29	No	RIP	0.260	0.274	0.269	6/03/2019
No.2	BD	E.E.	1968	2015	515	1.6	548	237	23/11/2022	2.28´10^{-12} (@25°C)	40	Good	11	0.03	✓	54	28	No	RIP	0.325	0.321	0.322	4/03/2020
No.3	BD	E.E.	1968	2015	500	1.7	532	571	23/11/2022	2.43´10^{-12} (@25°C)	37	Good	11	0.03	✓	41	27	No	RIP	0.279	0.286	0.276	4/03/2020
No.4	BD	WILSON	2002	-	-	-	700	-	23/11/2022	-	50	-	5	0.02	✓	70	34	Yes	OIP	0.502	0.512	0.526	8/02/2021
No.1	BMS	ABB	2015	-	-	-	700	-	20/07/2022	-	11	-	5	0.01	✓	76	36	No	RIP	0.402	0.388	0.400	1/06/2020
No.2	BMS	ABB	2015	-	-	-	700	-	20/07/2022	-	10	-	5	0.01	✓	68	37	No	OIP	0.402	0.390	0.386	2/06/2020
No.1	BY	A.E.I.	1967	Apr-13	480	1.2	600	700	17/01/2023	1.99´10^{-12} (@25°C)	42	Good	21	0.01	✓	38	36	No	RIP	0.274	0.275	0.274	18/03/2020
No.2	BY	ABB	2006	-	-	-	700	990	17/01/2023	-	41	-	5	0.01	✓	73	39	No	OIP	0.442	0.448	0.477	30/06/2020
No.1	CN	A.E.I.	1967	May-10	370	3.9	503	-	4/05/2022	4.56´10^{-12} (@25°C)	22	Fair	17	0.14	✓	55	18	No	RIP	0.322	0.321	0.324	25/09/2019
No.2	CN	A.E.I.	1967	May-12	445	3.0	576	-	4/05/2022	2.37´10^{-12} (@25°C)	24	Good	14	0.09	✓	52	19	No	RIP	0.322	0.304	0.314	22/04/2020
No.3	CN	WILSON	1990	08.06.18	575	1.2	694	-	4/05/2022	2.08´10^{-12} (@25°C)	22	Good	9	0.01	✓	63	38	No	OIP	0.662	0.741	0.712	11/03/2021
No.1	COO	WILSON	2007	-	-	-	700	-	28/01/2022	-	28	-	5	0.03	✓	63	35	Yes	OIP	0.363	0.347	0.378	20/11/2015
No.2	COO	WILSON	2012	-	-	-	700	-	28/01/2022	-	27	-	5	0.01	✓	73	36	No	RIP	0.364	0.350	0.358	6/08/2019
No.1	CS	TYREE	1976	May-13	550	1.1	650	-	4/04/2022	1.8´10^{-12} (@25°C)	21	Good	8	0.02	✓	60	26	No	RBP	0.451	0.795	0.624	12/02/2021
No.2	CS	WILSON	1976	May-13	520	1.0	677	-	4/04/2022	1.81´10^{-12} (@25°C)	21	Good	7	0.02	✓	61	26	No	RBP	0.419	0.351	0.364	27/02/2021
No.1	EP	WILSON	1963	May-13	440	2.6	650	-	22/03/2022	2.25´10^{-12} (@25°C)	21	Good	18	0.07	✓	54	20	No	RBP	0.967	0.614	0.984	1/04/2023
No.2	EP	ABB	2006	-	-	-	700	-	22/03/2022	-	22	-	5	0.02	✓	74	36	Yes	OIP	0.394	0.395	0.398	10/02/2021
No.3	EP	GEC/MV	1959	-	-	-	588	-	22/03/2022	-	24	-	25	0.02	✓	38	30	No	RBP	0.718	0.752	0.744	28/08/2020
No.4	EP	ENGLISH ELECTRIC	1958	-	-	-	650	-	22/03/2022	-	20	-	10	0.03	✓	67	28	No	RBP	0.374	0.432	0.455	10/11/2021
No.3	EPN	WILSON	2015	-	-	-	700	-	16/10/2022	-	23	-	5	0.01	✓	44	42	-	RIP	0.338	0.331	0.331	28/08/2020
No.2	ES	WILSON	2019	-	-	-	700	1225	3/02/2022	-	20	Good	6	0.01	✓	48	35	No	RIP	0.330	0.320	0.330	16/03/2019
No.3	ES	WILSON	2018	-	-	-	700	1143	3/02/2022	-	18	Good	5	0.01	✓	56	37	No	RIP	0.340	0.340	0.350	14/08/2018
No.1	FE	WILSON	2010	-	-	-	700	-	12/01/2022	-	20	-	5	0.01	✓	57	37	No	OIP	0.530	0.488	0.439	6/04/2020
No.2	FE	AEI	1967	2014	460	4.3	604	430	6/04/2022	1.79´10^{-12} (@25°C)	13	Good	10	0.01	✓	60	39	No	RIP	0.419	0.412	0.415	18/07/2022
No.1	FF	WILSON	2018	-	-	-	700	1073	16/03/2022	-	26	-	5	0.01	✓	53	37	No	-	N/A	N/A	N/A	-
No.2	FF	WILSON	2019	-	-	-	700	1267	16/03/2022	-	26	-	5	0.01	✓	59	35	No	-	N/A	N/A	N/A	-
No.3	FF	E.E.	1960	-	-	-	468	250	23/03/2020	-	40	-	31	0.1	✓	35	20	No	-	N/A	N/A	N/A	-
~~Spare~~	~~FF~~	~~A.G.E.~~	-	-	-	-	-	-	~~11/04/2022~~	-		-	~~6~~	-	~~ü~~	~~64~~	~~20~~	~~No~~	-	~~N/A~~	~~N/A~~	~~N/A~~	-
No.1	FT	WILSON	1970	2014	500	2.1	656	-	27/01/2022	2.06´10^{-12} (@25°C)	44	Good	32	0.05	✓	30	21	No	RBP	0.525	0.505	0.522	29/03/2023
No.2	FT	WILSON	1970	2014	495	2.1	665	-	7/10/2022	2.23´10^{-12} (@25°C)	40	Good	7	0.05	✓	72	20	No	RBP	0.514	0.519	0.518	30/03/2023
No.1	FW	A.E.I.	1966	May-13	435	2	631	-	11/04/2022	1.98´10^{-12} (@25°C)	22	Good	16	0.02	✓	42	28	No	RIP	0.360	0.347	0.353	6/06/2020
No.2	FW	A.E.I.	1966	May-13	380	2.2	631	-	3/05/2022	1.83´10^{-12} (@25°C)	23	Good	14	0.02	✓	74	27	No	RBP	0.997	0.853	1.024	8/04/2020
No.3	FW	E.E.	1971	May-11	365	1.6	569	-	27/01/2022	3.54´10^{-12} (@25°C)	58	Good	10	0.11	✓	59	18	No	RBP	0.422	0.372	0.388	9/04/2020
~~No.1~~	~~HB~~	~~W.E.T.~~	~~1966~~	~~May-11~~	~~230~~	~~4.9~~	~~650~~	~~260~~	~~7/02/2022~~	~~7.73´10^{-12} (@25°C)~~	34	~~Fair~~	~~18~~	~~0.03~~	~~✓~~	~~42~~	~~28~~	~~No~~	~~RBP~~	~~0.544~~	~~0.839~~	~~1.038~~	~~13/06/2020~~
No.2	HB	WILSON	2023		-	-	-	-	3/04/2023	968.3E-15 (@23°C)	27		5	0.01	✓	71	37.1	-	RIP	0.320	0.309	0.303	14/01/2023
No.3	HB	W.E.T.	1966	May-14	295	2.8	645	500	7/02/2022	3.44´10^{-12} (@25°C)	32	Good	18	0.02	✓	33	28	No	RBP	1.094	0.971	1.075	14/06/2020
No.1	MAT	WILSON	2002	-	-	-	700	-	29/03/2022	-	20	-	5	0.02	✓	65	34	-	OIP	0.508	0.504	0.569	10/03/2023
No.2	MAT	WILSON	2002	-	-	-	700	-	29/03/2022	-	20	-	5	0.02	✓	64	37	-	-	-	-	-	-
No.3	MAT	WILSON	2015	-	-	-	700	-	29/03/2022	-	21	-	5	0.01	✓	60	37	-	-	0.310	0.305	0.305	25/10/2021
No. 1	NEL	WILSON	2021	-	-	0.8	>1000		3/02/2022		20		8	0.01	✓	76	34	No	RIP	0.312	0.327	0.311	9/02/2022
No. 2	NEL	WILSON	2021	-	-	0.8	>1000		3/02/2022		25		8	0.01	✓	72	32	No	RIP	0.317	0.308	0.304	31/01/2022
No.1	NH	TYREE	1973	2015	605	1	677	-	2/05/2022	2.32´10^{-12} (@25°C)	19	Good	11	0.01	✓	59	28	No	RBP	0.379	0.565	0.557	23/05/2023
No.2	NH	TYREE	1973	2015	600	0.9	688	-	2/05/2022	2.04´10^{-12} (@25°C)	20	Good	10	0.01	✓	60	27	No	RBP	0.389	0.411	0.407	24/05/2023
No.3	NH	WILSON	2005	-	-	-	700	-	2/05/2022	-	18	-	5	0.01	✓	73	34	Yes	OIP	0.464	0.447	0.455	24/05/2023
No.1	NS	WILSON	2017	-	-	-	700	-	28/09/2022		12	-	5	0.01	✓	47	41	-	-	N/A	N/A	N/A	-
No.2	NS	WILSON	2017	-	-	-	700	-	18/11/2022		30	-	5	0.01	✓	66	40	-	-	N/A	N/A	N/A	-
No.3	NS	WILSON	2017	-	-	-	700	1032	28/09/2022		12	-	5	0.01	✓	56	41	-	-	N/A	N/A	N/A	-
No.1	NT	E.E.	1949	May-12	450	1.8	588	520	28/11/2022	3.08´10^{-12} (@25°C)	20	Good	16	0.03	✓	49	30	No	RBP	0.995	0.989	1.136	17/02/2021
No.3	NT	E.E.	1949	May-12	375	2.3	600	-	28/11/2022	4.17´10^{-12} (@25°C)	20	Good	19	0.03	✓	33	29	No	RBP	0.557	0.625	0.689	18/02/2021
~~No.1~~	~~P~~	~~J&P~~	~~1958~~	-	-	-	~~572~~	-	~~12/04/2017~~	-		-	~~30~~	~~0.04~~	~~ü~~	~~55~~	~~29~~	~~No~~	~~RBP~~	~~0.771~~	~~0.883~~	~~0.752~~	~~19/11/2015~~
~~No.1 Reactor~~	~~P~~	~~A.E.I.~~	~~1958~~	-	-	-	~~688~~	-	~~12/05/2017~~	-		-	~~8~~	~~0.02~~	~~ü~~	~~63~~	~~27~~	-	-	-	-	-	-
~~No.2~~	~~P~~	~~J&P~~	~~1958~~	-	-	-	~~466~~	-	~~12/04/2017~~	-		-	~~33~~	~~0.23~~	~~?~~	~~40~~	~~16~~	~~No~~	~~RBP~~	~~0.778~~	~~0.698~~	~~0.829~~	~~17/03/2016~~
~~No.2 Reactor~~	~~P~~	~~A.E.I.~~	~~1957~~	-	-	-	~~688~~	-	~~12/05/2017~~	-		-	~~10~~	~~0.02~~	~~ü~~	~~71~~	~~29~~	-	-	-	-	-	-
No.1	PTN	WILSON	2019	-	-	-	700	-	22/03/2022		18		5	0.01	✓	58	38	-	RIP	0.336	0.352	0.335	20/05/2019
No.2	PTN	WILSON	2019	-	-	-	700	-	23/03/2022		18		5	0.01	✓	70	38	-	RIP	0.357	0.368	0.348	22/05/2019
No.1	PV	WILSON	2011	-	-	-	700	-	28/01/2022	-	40	-	5	0.01	✓	75	34	No	RIP	0.346	0.338	0.317	18/04/2018
No.2	PV	WILSON	2012	-	-	-	700	-	28/01/2022	-	38	-	5	0.01	✓	51	37	No	RIP	0.300	0.305	0.312	19/04/2018
No.3	PV	BRYCE	1964	May-10	320	2.9	580	-	22/03/2022	5.08´10^{-12} (@25°C)	25	Fair	24	0.05	✓	40	25	No	RBP	1.096	0.868	1.121	5/03/2021
No.1	SBY	WILSON	2002	-	-	-	671	-	1/02/2022	-	22	-	9	0.04	✓	60	24	Yes	OIP	0.464	0.483	0.512	10/11/2022
No.2	SBY	WILSON	2018	-	-	-	700	-	1/02/2022		23	-	5	0.01	✓	58	35	No	RBP	0.748	0.813	0.734	9/02/2016
No.3	SBY	WILSON	2000	-	-	-	700	-	1/02/2022	-	23	-	13	0.02	✓	36	35	Yes	OIP	0.552	0.563	0.515	3/02/2021
No.1	SHM	ABB	2008	-	-	-	700	-	1/02/2022	-	21	-	5	0.01	✓	65	38	No	OIP	0.426	0.442	0.429	23/02/2021
No.2	SHM	WILSON	2010	-	-	-	700	-	1/02/2022	-	23	-	5	0.01	✓	49	38	No	RIP	0.312	0.302	0.300	24/02/2021
No.1	ST	WILSON	1985	2017	670	1.5	636	-	3/11/2022	1.98´10^{-12} (@25°C)	16	Good	11	0.02	✓	47	26	No	RBP	0.445	0.473	0.501	2/03/2021
No.2	ST	WILSON	1985	2017	695	1.3	661	-	3/11/2022	2.05´10^{-12} (@25°C)	16	Good	8	0.01	✓	50	28	No	RBP	0.474	0.451	0.463	3/03/2021
No.3	ST	WILSON	1996	-	-	-	482	-	3/11/2022		16	-	5	0.08	✓	73	19	No	OIP	0.392	0.391	0.358	4/03/2021
No.1	TH	W.E.T.	1984	2017	590	1.5	683	-	29/07/2022	2.21´10^{-12} (@25°C)	26	Good	11	0.02	✓	38	25	No	RBP	0.493	0.446	0.343	25/02/2021
No.2	TH	W.E.T.	1984	2017	475	2.1	671	-	29/07/2022	2.44´10^{-12} (@25°C)	22	Good	12	0.06	✓	58	21	No	RBP	0.596	0.586	0.589	24/02/2021
No.1	TMA	ABB	2014	-	-	-	700	-	14/10/2022	-	18	-	5	0.01	✓	52	39	-	RIP	0.280	0.264	0.263	25/08/2020
No.2	TMA	ABB	2014	-	-	-	700	-	14/10/2022	-	18	-	5	0.01	✓	45	39	-	RIP	0.253	0.184	0.236	25/08/2020
No.1	YVE	WILSON	2013	-	-	-	700	-	29/07/2022	-	23	-	5	0.01	✓	61	36	No	RIP	0.316	0.310	0.305	17/04/2020
No.2	YVE	WILSON	2013	-	-	-	700	-	29/07/2022	-	23	-	5	0.01	✓	72	34	No	RIP	0.356	0.323	0.338	20/04/2020
No.4	YVE	WILSON	2000	-	-	-	700	-	29/07/2022	-	23	-	5	0.01	✓	65	34	-	OIP	0.520	0.508	0.501	6/02/2021

1.20 APPENDIX F – TRANSFORMER CYCLIC RATINGS

LCR	Limited Cyclic Rating
C	Cyclic Rating
NP	Name Plate Naming

ZS Station	No. of Tx	No.1 Tx Rating (MVA)			Tx CB	No.2 Tx Rating (MVA)			Tx CB	No.3 Tx Rating (MVA)			Tx CB	No.4 Tx Rating (MVA)			Tx CB
		LCR	C	NP		LCR	C	NP		LCR	C	NP		LCR	C	NP	
AW	4	36	34	30	45.7	38	36	30	45.7	36	34	30	45.7	48.8	45.5	40	47.6
BY	2	37.4	34	30	47.6	42.9	39.6	33	47.6								
BD	4	40	38.9	30	45.7	40	38.9	30	45.7	40	38.9	30	45.7	42.9	39.6	33	76.2
BMS	2	45	42	33	47.6	45	42	33	47.6								
CN	3	41.3	37.2	30	45.7	41.3	37.2	30	45.7	42.9	39.6	33	47.6				
CS	2	44	40	33	45.7	44	40	33	45.7								
COO	2	42.9	39.6	33	47.6	45	42	33	47.6								
EPN	1	45	42	33	76.2												
EP A	1&3	32	30	27		18	17	13									
EP B	2&4	32	30	27		18	17	13									
ES	2	36	36	27	47.6	36	36	27	47.6								
FF	3	15.6	14.5	13.5	28.5	15.6	14.5	13.5	28.5	15.6	14.5	13.5	28.5				
FT	2	36	33	30	30.5	36	33	30	30.5								
FE	2	45	42	33	30.5	37.4	34	30	30.5								
FW	3	36	33	30	45.7	36	33	30	45.7		36	30	45.7				
HB	2	32.4	32.4	30	47.6	32.4	32.4	30	47.6								
NT	2	41	41	38	76.2	41	41	38	76.2								
NS	3	15.4	14	13.5	47.6	14.7	13.4	13.5	47.6	14.5	13.2	13.5	47.6				
NH	3	39.1	37.6	30	45.7	39.1	37.6	30	45.7	39.1	37.6	30	45.7				
PV	3	45	42	33	47.6	45	42	33	47.6	15	13	10	47.6				
P	2	26.2	20.3	20	13.7	26.2	20.3	20	13.7								
ST	3	38	38	33	47.6	38	38	33	47.6	38	38	33	47.6				
SBY	3	21	19.5	16	30.5	13.4	12.8	10	19.3	21	19.5	16	30.5				
SHM	2	45	42	33	47.6	45	42	33	47.6								
TH	2	49.5	49.5	45	47.6	49.5	49.5	45	47.6								
TMA	2	45	42	33	47.6	45	42	33	47.6								
YVE	2	45	42	33	76.2	45	42	33	76.2								

1.21 APPENDIX G – TRANSFORMER BUNDING STATUS

Sub	Oil Containment	Notes
AW - Airport West	Yes	
BD - Broadmeadows	Yes	
BMS - Broadmeadows South	Yes	
BY - Braybrook	No	A triple interceptor pit was installed when the second transformer project was completed. The need for a Humeceptor is to be evaluated.
CN - Coburg North	Yes	
COO - Coolaroo	Yes	
CS - Coburg South	No	Part of the switchgear upgrade project Merri creek approx. 2km away.
EP - East Preston	No	Bunding & Humeceptor will be part of the station rebuild.
EPN - East Preston	Yes	
ES - Essendon	Yes	
FE - Footscray East	Yes	
FF – Fairfield	No	Completed except for the No.3 transformer.
FT - Flemington	No	Part of the future 3rd transformer project.
FW - Footscray West	Yes	
HB - Heidelberg	Yes	
MAT- Melbourne Airport	Yes	
NEL – North East Link	Yes	Also fitted with a [redacted] water filter.
NH - North Heidelberg	Yes	
NS - North Essendon	Yes	
NT - Newport	Yes	
PTN- Preston	Yes	
PV - Pascoe Vale	Yes	
SBY - Sunbury	Yes	
SHM - Sydenham	Yes	
ST - Somerton	Yes	
TH - Tottenham	Yes	
TMA - Tullamarine	Yes	
YVE - Yarraville	Yes	

1.22 APPENDIX H – ZSS ROOF CONDITION

ZSS	Roof Condition	Initial Action	Comments	Action - 19/08/2015	Progress - 16/06/2016
NS	East metal deck- Significant surface rust - refer photo	Do nothing – 11kV Switch Room building roof will be replaced as part of 2016/17 Transformer Replacement Project.	**Priority 1:** Require a quote to replace 8m of flashing on the south-East end of the roof. Also repair 8m of roofing on the North –East end of the roof. See Rob for details.	Complete ASAP in 2015 - first priority. Ensure that no water is leaking onto the switchgear. Replace the roof in 2016 as part of the transformer project - Simon to get a price from Daniel Lau. In NS SoW.	
NT	Significant moss growing on roof. No visible signs of leaks.	Remove moss and clean roof (using high-pressure cleaner).	**Priority 2:** Quote to Remove 3 sections of ridge capping. Clean all dirt and rubbish out. Install new ridge capping if the old one cannot be re installed.	PO created and work scheduled for 13-14 October. Works completed: 1. 3 sections of ridge capping removed. 2. All dirt, leaves etc cleaned from under ridge capping. 3. All 3 ridge cappings replaced with new over sized ridge capping.	Work completed 13-14 October 2015. PM Order 5136021.
EP	Paint flaking off all over the roof	Repaint the roof as the switch room will remain in service until 2021/22.	**Priority 3:** **Switch House A:** Repair rust on roofing sheets - eves at west end. Replace rusted gutter at West end. Go over whole roof sheets and replace loose nails with roofing screws. Spot treat rust spots. **Switch House B:** Spot treat rust spots with rust paint – there's not many rust spots. Re silicon 2 roof wind fans to stop leaks. Push out dent in one roof sheet.	Action as per quote. Speak to Darren Trafford as he is managing the EP site. Complete in 2015.	
ES	Old roof has surface rust over majority of surface. Suggest painting roof to prolong life span of sheets.	Treat surface rust by painting.	**Priority 4:** **Quote 1:** repaint entire roof with Rust Grip paint as you have recommended. Can you provide some documentation or specs on the paint please. **Quote 2 :** repaint entire roof with a locally available exterior grade rust inhibiting paint.	Repaint roof as per quote. Complete in 2015. Need to update the ACS Buildings & Grounds to include the condition of the roof and the issue for each ZSS. Need a BC to replace the roof in the near future - could be as part of the transformer replacement project? Check scope. Decided to wait until transformer project in 2018/19 and replace for an estimated $35k (estimate from James Michael). Roof expected to last next 4 years. Monitor.	Continue to monitor condition until replacement in 2018/19.
BD	Surface rust in some areas	Do nothing – control building will be demolished as part of control building and relay replacement project in 2016.		Treat rust. Use a wire brush, kill rust and then apply rust protective paint. Explore market to find a suitable product.	
CN	Some surface rust on roof	Treat the surface rust. Building will be extended in 2018/19 to accommodate the relay upgrades.		Treat rust. Use a wire brush, kill rust and then apply rust protective paint. Explore market to find a suitable product.	
FT	Flashings and several areas on roof have surface rust.	Treat rust on roof and flashings to prolong life. Roof will be in-service until at least 2021.		Treat rust. Use a wire brush, kill rust and then apply rust protective paint. Explore market to find a suitable product. Replace capping where it is severely rusted, otherwise spot treat.	
PV	Significant surface rust on mess room roof	Replace the roof as the rust damage looks extensive.		Comms equipment inside. Add to ACS for roof replacement. Replace in 2016? Check budget and prioritise. Inspect annually.	Initiate a Gate 3 or do as part of minor capex works in 2016/17. Replaced in 2017
AW	Small amount of surface rust	Do nothing – control building will be demolished as part of control building and relay replacement project in 2016.		Need to revisit treating the roof if the project is deferred. To be reinspected annually. Add to Standard Job to inspect the condition of the roof, as part of gutters or static line inspection.	
FE	No evidence of corrosion/deterioration.	None. Roof to be replaced as part of switchgear replacement project in 2018/19?		No action required. Look at BC for FE to check if the roof needs to be replaced.	
FW	Surface rust covering roof area – suggest to paint with rust grip to prolong roof life. Gutters not rusted but needs painting on outside - existing paint peeling off.	Monitor roof condition to determine if action is required prior to roof replacement.		Check BC if it includes roof replacement. If so, monitor condition until project is completed.	
P				Revisit and take photos at P.	
TH	No evidence of corrosion/deterioration but dirt against flashing may cause problems in the future.	Remove dirt and clean roof (using high-pressure cleaner).		Cleaning to be scheduled. **CAUTION** - do not use pressure cleaner to avoid driving water under flashing into the switchroom.	
SSS gate	Pedestrian gate	The pedestrian gate can be opened via the internal Push Bar relatively easy with the use of a bar, stick etc. through the cyclone fencing. We need to amend this as it is a safety risk. Do you have any ideas how we can fix this issue (i.e. install sheets on the surrounding cyclone fencing so objects cannot be put through the fence to gain access to the push bar mechanism (although it will still be accessible from the top), a different type of emergency exit mechanism)?		Fixed.	
YVE	No evidence of corrosion/deterioration.	None.		No action required.	

1.23 APPENDIX I – CRITICAL SPARES ASSESSMENT

Note: predicted minimum spares may be adequately addressed by the existing inventory management process.

Inventory Information								Asset Use and Failure Consequence					Stock Decision	Total Cost (Risk Cost, Purchase Cost and Holding Cost)							Predicted Minimum Spares Required
Part Description	Current Min Stock Level	Current Max Stock Level	Purchase Cost	Economic Reorder Level	Holding Cost of Spare Part ($)	Delivery Lead Time (Days)	Substitute Parts	No of Assets Using Part	Utilisation of the Asset (%) *(What percentage of time is this part required)*	Mean Time Between Failure (years)	Failure Risk Cost Per Day	Estimated Spare Consumption Per Year	Is it economically feasable for item to be stocked?	Lambda T	0	1	2	3	4	5	Min
Zone Substation Transformer	0	0	[redacted]	0	1000	240	no	66	100%	20	0	0.1	N	2.2	0	770000	1540000	2310000	3080000	3850000	0
Zone Substation Circuit Breaker	29	29	[redacted]	0	100	180	no	468	100%	20	0	0.1	Y	11.5	0	77000	154000	231000	308000	385000	0
Zone Substation Disconnectors and Buses	0	0	[redacted]	0	10	90	no	766	100%	20	0	0.1	Y	9.4	0	20200	40400	60600	80800	101000	0
Zone Substation Instrument Transformer	3	3	[redacted]	0	50	180	no	532	100%	20	0	0.1	Y	13.1	0	11000	22000	33000	44000	55000	0
Zone Substation Capacitor Banks	0	0	[redacted]	0	10	90	no	38	100%	20	0	0.1	Y	0.5	0	4200	8400	12600	16800	21000	0
Zone Substation Buildings and Grounds	0	0	[redacted]	0	0	90	no	30	100%	20	0	0.1	N	0.4	0	750000	1500000	2250000	3000000	3750000	0
Zone Substation Earthing System	0	0	[redacted]	0	0		no	30	100%	20	0	0.1	Y	0.0	0	400000	800000	1200000	1600000	2000000	0

1.24 APPENDIX J – ASSET CRITICALITY ASSESSMENT WORKSHEET

ASSET CRITICALITY ASSESSMENT WORKSHEET

ASSET AND BACKGROUND INFORMATION	
Site Name	General
Asset Class	Primary Plant
Sub-Asset Class	All
Date of Original Assessment	15-May-18
Date of Last Review	19-Jul-18
Reviewed By (where applicable):	

Risk Ref. No.	Description of Asset or Asset Grouping	Description of Risk	Consequence Category (Operational, HSE, Reputation etc.)	Description of Consequences	Current Controls	Criticality Score	Criticality Rating
1	Zone Substation Transformer	The risk associated with failure of zone substation transformers i.e. fails to insulate and/or carry load, resulting in: • Injury • Plant damage • Environmental damage (oil spill) • Loss of supply	Operational, HSE	Consequence: Health, Safety & Environment / Operational **Major** due to: • Potential loss of life to staff or contractor • Loss of electricity supply to >2% customers (6,500) > 24 hours	As per ACS	AC4	High
2	Zone Substation Grounds	Potential for unauthorised access within Jemena zone substations, resulting in trip hazards, equipment failure due to vandalism, initiation of fire and/or oil spill	Operational, HSE	**Major** due to: - total permanent disability (staff or contractors), multiple hospitalisations, permanent disability and/or life-threatening injuries affectic member(s) of the public - Loss of electricity supply to >2% customers (6,500) > 24 hours Likelihood: Rare due to lack of incidents occuring within the last 10 years within the JEN network	As per ACS	AC4	High
3	Disconnectors and Buses	The risk associated with the failure of disconnector and buses i(.e. fails to insulate, etc.) resulting in • Plant fails to insulate • Plant fails to open or close, High resistance connection • Catastrophic plant failure (Porcelain) • Plant rating (overload or under-rated)	Operational, HSE	**Major** due to: • Potential life threatening injury to staff, contractors or public • Loss of electricity supply to >2% of customers (6,500) > 24 hours Likelihood: Rare due to lack of incidents occurring within the last 10 years within the JEN network	As per ACS	AC4	High
4	Switchgear	The risk associated with the failure of switchgear i.e. operation malfunction or explosive failure, resulting in: • Injury • Plant damage • Environmental damage (oil spill) • Loss of supply • Financial impact varies based on consequence and can be between $200K	Operational, HSE	**Major** due to: • Potential loss of life to staff or contractor • Regulatory investigations or government review • Loss of electricity supply to >2% of customers (6,500) > 24 hours Likelihood: Rare due to lack of incidents occurring within the last 10 years within the JEN network.	As per ACS	AC4	High
5	Capacitor bank failure	The risk associated with failure of capacitor bank, resulting in: • Poor power factor and regulatory non-compliance • Explosion of capacitor unit and tank rupture, resulting in expulsion of porcelain fragments and shrapnel • Explosion of reactor unit and tank rupture, resulting in oil leak (may also contain PCB) and possible fire start	Operational, HSE	**Minor** due to: • General regulatory queries regarding supply quality • No violation, breaches, fines or penalties Likelihood: Likely due frequent loss of capacitor banks	As per ACS	AC1	Low
6	Instrument transformer failure	The risk associated with failure of instrument transformer, resulting in: • Failure to adhere to regulations or code requirements • Expulsion of porcelain fragments and shrapnel • Loss of oil and fire start	Operational, HSE	**Serious** due to: • Medical treatment injury or lost time injury (staff or contractors) • Loss of electricity supply to >1% customers (3,200) > 6 hours	As per ACS	AC2	Moderate
7	Zone Substation Earthing	The risk of electric shock to internal employees, contractors or the public caused by inadequate substation HV earthing system (i.e. high resistance earth, step & touch potential under fault conditions, non-operation of HV protection)	Operational, HSE	**Major** due to: - potential life-threatening injuries to staff, contractors or member(s) of the public - inability to detect earth faults preventing operation of HV protection systems Likelihood: Possible due to a chance that it could happen in the next 5 years and increasing incidence of theft.	As per ACS	AC4	High

1.25 APPENDIX K – CONDITION BASED RISK MANAGEMENT

CBRM inputs and outputs

Critical CBRM inputs include:

- the engineering knowledge and practical experience of the assets from within the asset owner;
- asset specification, history (faults, failures, generic experience, maintenance records), duty, environment, test and inspection results;
- understanding of degradation and failure modes, and
- experience of building CBRM models.

CBRM outputs include:

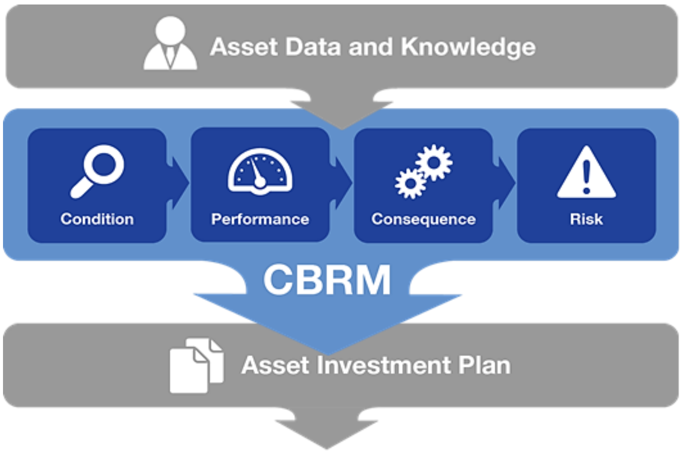
- Part 1 – Condition, which provides:
  - health indices, health index profiles, probability of failure (POF) and failure rates; and
  - estimates of future failure rates with different interventions.
- Part 2 – Risk, which provides:
  - quantification of current and future risk for asset groups with different interventions (expressed as a monetary value);
  - criticality, involving changes priority within an asset group; and
  - comparison/optimisation across asset groups.

CBRM procedures

Figure 7–3 shows an overview of the CBRM. The CBRM process followed by JEN to develop the model was:

- Determine an asset health index (HI) and ageing rate for each power transformer;
- Determine the probability of failure for each power transformer;
- Determine the consequences of failure;
- Evaluate the associated financial risk, and
- Assess future scenarios and options

Figure 7–3: CBRM Overview

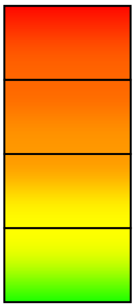


CBRM Health Index (HI)

The final Health Index (HI) profile for the asset class is calculated at year 0 (current year) and at any other arbitrary year in the future to determine the asset replacement volumes for each specific asset class. A maximum health index cap of 7 is assigned for every asset class to indicate the need of replacement. This is illustrated schematically in Figure 7–4 below.

Figure 7–4: Concept of Health Indices

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 represents the extent of degradation as follows:

- Low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal ageing, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the PoF remains very low and the condition and PoF would not be expected to change significantly for some time.
- Medium values of health index, in the range 4 to 7, represent significant deterioration, with degradation processes starting to move from normal ageing to processes that potentially threaten failure. In this condition, the PoF, although still low, is just starting to rise and the rate of further degradation is increasing.

High values of health index (>7) represent serious deterioration; i.e. advanced degradation processes now reaching the point that they actually threaten failure. In this condition the PoF is now significantly raised and the rate of further degradation will be relatively rapid.