STRATEGY

JEN – RIN – SUPPORT – ELECTRICITY SECONDARY PLANT ASSET CLASS STRATEGY – 20250131

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PUBLIC

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DOCUMENT HISTORY

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1.0	25/10/2017	Combined zone substation ACS into one document and enhanced to new template
2.0	30/08/2018	Updates and addition to address Information, Risk, Spares and Criticality definition
2.1	12/04/2019	Updates based on feedback received from GHD
3.0	20/12/2019	Rewritten based on subsequent feedback from GHD
4.0	1/04/2022	Updated document number previously ELE AM PL 0062 and template
5.0	03/2024	Wholistic update and addition of Asset Portfolio Objectives
6.0	04/2024	General update of asset information and CAPEX & OPEX estimates
7.0	12/2024	ACS update – EDPR submission

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EXECUTIVE SUMMARY

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

This ACS document pertains to Electricity Secondary Plant, a term that denotes a range of equipment that is used in zone substations. Electricity Secondary Plant encompasses all the necessary on-site equipment and systems to protect and control Electricity Primary Plant (load carrying equipment such as transformers, circuit breakers and bus switches).

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

- Protection & Control equipment
- DC Supply System
- Communications Cabling
- Multiplexers and MPLS equipment
- Radio & Cellular
- Remote Terminal Units (RTUs) and Gateways
- Communication Network Devices
- GPS Clocks

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

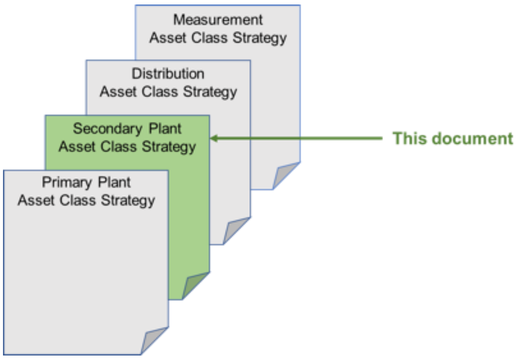
1. INTRODUCTION

This ACS covers the JEN secondary 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 secondary plant asset class.

Asset life cycles are considered in three stages: creation (acquisition), maintenance or replacement (as applicable), and disposal. Investment recommendations across each of these three stages are made 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 distribution assets in this ACS are categorised into the following sub-asset classes located in the following sections of this document:

4.1 Protection & Control Systems

4.2 DC Supply Systems

4.3 Zone Substation SCADA and Communications Systems

4.4 Operational Technology

1.1 PURPOSE

The purpose of the ACS Electricity Secondary Plant 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). Based on this information, this ACS contributes to short, medium and long-term planning.

This secondary plant ACS addresses:

- Secondary plant asset management practices;
- Sub-asset risk causes and consequences;
- Sub-asset performance against objectives, drivers, and service levels;
- Sub-asset class specifications and life cycle management of electricity secondary 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

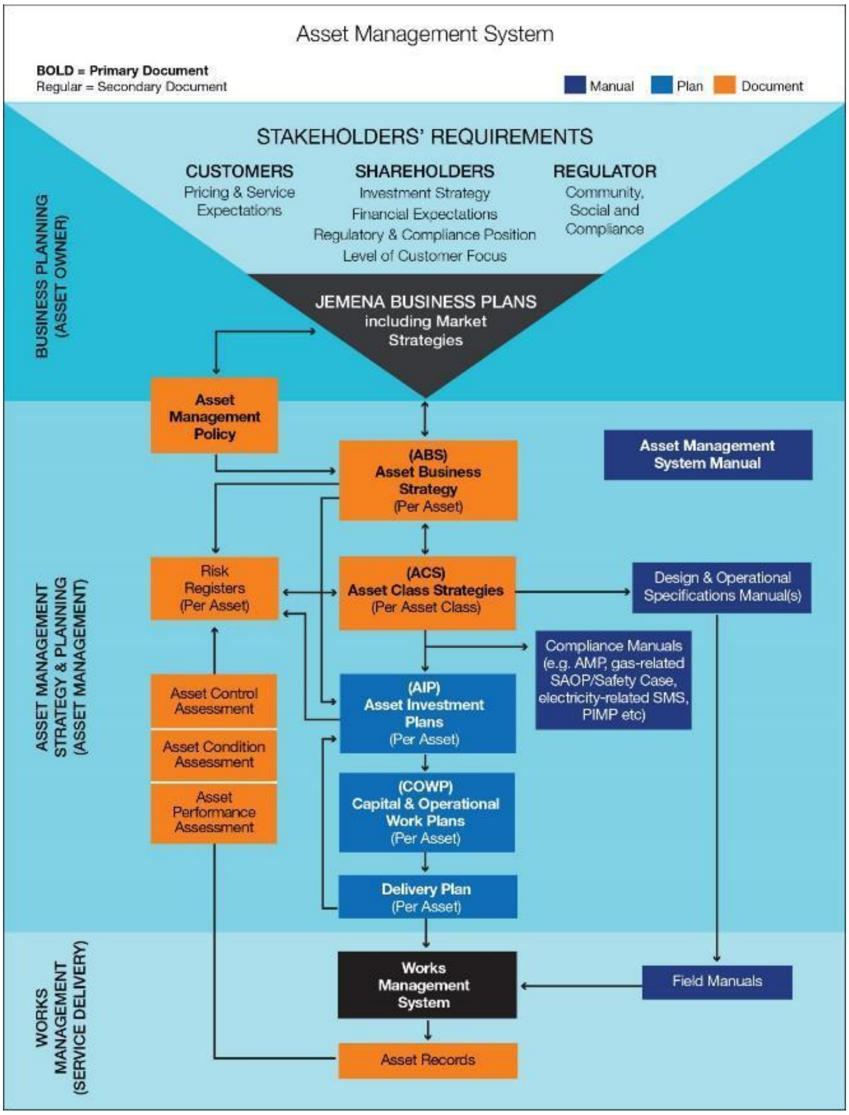
Asset management is the coordinated activity that we undertake to optimise the value of our electricity network when providing electricity distribution services to our customers. It involves balancing of efficient costs, opportunities and risks against performance. An AMS enables a systematic approach 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.

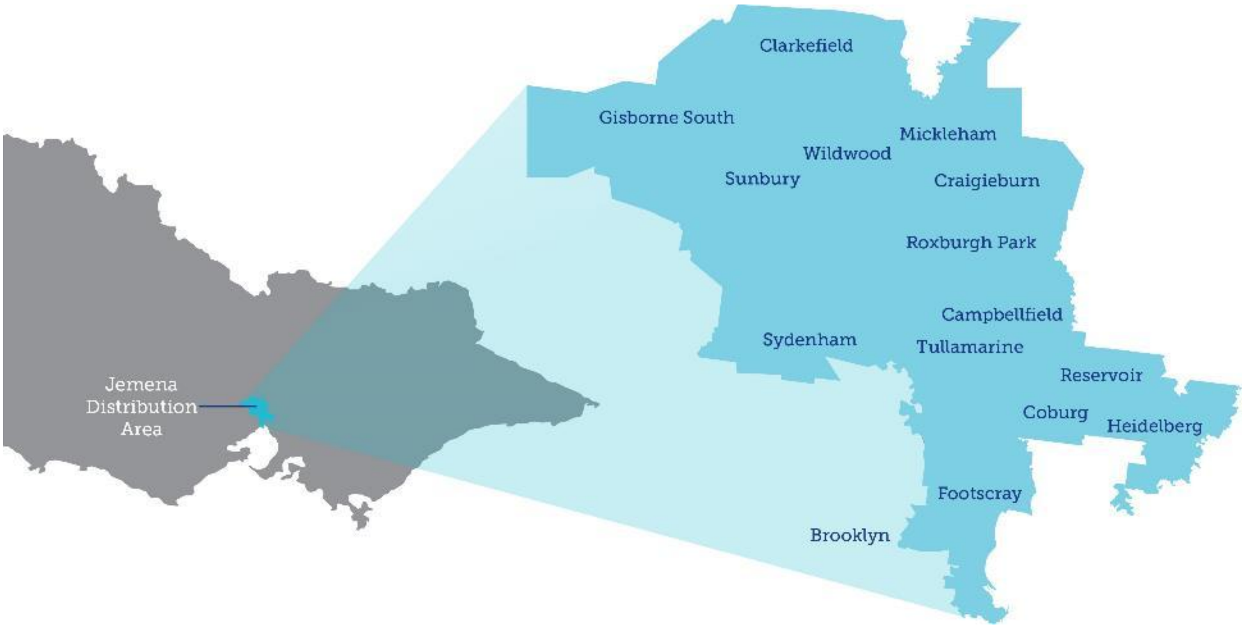
Figure 1-2 – JEN's Asset Management System



1.3 DESCRIPTION OF ASSETS COVERED

With sub-assets, such as protection and control relays or DC supply systems, there are risks of high consequence-of-failure impacting Health, Safety and Environmental (HSE) objectives and/or supply reliability. Back-up protection is intrinsically designed into zone substation secondary systems. When a fault occurs and the initial protection fails to function, the back-up protection scheme is designed to activate. The extent of that outage would be greater because the back-up scheme is upstream of the initial scheme.

Figure 1–3: JEN's geographical footprint



There are many secondary plant assets with varying degrees of severity if there is a failure.

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

- 1,836 Protection and Control Devices ranging in age from 0 to 60 years;
- (88) 78 Battery Banks and Battery Chargers for DC Supply Systems;
- 34 RTUs ranging in age from 1 to 26 years;
- 21 GPS Clocks ranging in age from 1 to 18 years;
- 56 Communications Network Devices ranging in age from 1 to 12 years;
- 83 Multiplexers ranging in age from 2 to 18 years;
- 263 Radio Transceivers and Cellular Modems ranging in age from 1 to 18 years; and
- 348 km of Communications Cable ranging in age from 3 to 75 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 and Operations – Electricity.

The ACS is reviewed every three years to ensure alignment with 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 and Approver
Secondary Team personnel	Protection and control equipment engineers
	DC supply system equipment engineers
	Zone substation SCADA system equipment engineers
	Operational technology communication system equipment engineers

2 STRATEGIC DRIVERS

2.1 JEN'S 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.

2.2 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 out by the:

- Australian Energy Regulator (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, adhere to the NER and meet safety obligations. There are ongoing compliance, analysis and reporting requirements that JEN is required to perform with regard to 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 cover:

- Promoting 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 co-ordinated and integrated designs are particularly focused on attributes of robust long life, security, reliability, cost effectiveness 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.

3.1 ASSET PORTFOLIO OBJECTIVES

Secondary plant equipment forms part of an over-arching scheme and philosophy that is adopted for the application. Individual sub-asset class strategies and equipment are then combined with a holistic approach to create an asset portfolio of equipment to meet Asset Management objectives.

3.1.1 DIGITAL SUBSTATION

A digital substation involves an integrated implementation of the Communication Networks and Systems in Substations standard (including IEC 61850 implementation at station bus and process bus levels). The integrated systems solution relies on several assets such as digital protection and control devices, SCADA systems and communications systems that work together on a common framework to deliver the required functionality of a digital substation. The standard defines the communication protocols for substation Intelligent Electronic Devices (IEDs) to facilitate interoperability of devices from different vendors.

Implementation of the standard is a direct response to addressing energy industry megatrends such as Digitisation and Decentralisation. Furthermore, the digital substation strategy enables Asset Management Objectives in Customer, Data, Operational Excellence and Innovation areas to be achieved.[1]

Benefits aimed to be realised by a digital substation are:

- Lower design and configuration costs

[1] ELE PL 0019, Jemena Asset Business Strategy 2020-2039

- Lower installation, testing and commissioning costs
- Interoperability between different vendor IEDs
- Greater system flexibility and scalability
- Increased efficiency in data handling and implementation of innovative solutions and smart grid features
- Improved safety with more sophisticated interlocking and condition monitoring
- Reduced maintenance costs
- Efficient system analysis and troubleshooting.

To realise these benefits, Sub-Asset Class strategies of the following equipment are to consider Digital Substation objectives:

- Protection and Control systems
  - IEDs
  - Auxiliary equipment (AC and DC)
- SCADA systems
  - RTUs
  - Engineering workstations / Human Machine Interface (HMI)
  - GPS clocks
- Communications systems
  - Network devices
  - Multiplexers
  - Communications cabling
  - Multi-Protocol Label Switching (MPLS)
- Standardise DC voltage across all sub-asset class.

3.1.2 DISTRIBUTION AND SUBSTATION MONITORING

The electricity market and distribution networks are undergoing rapid changes as it transforms towards a decarbonised future driven by technology and market innovations, policy and regulatory developments and changing customer needs. While details of this transformation remain uncertain, managing this transformation by resolving existing issues and mitigating risks in an efficient and cost-effective way will be the biggest challenge.

Technology advancements has changed the way customers use the network as the electricity market shifts towards a two-way service. Traditionally, JEN have good visibility of the HV network and relied on predictable customer behaviours and loads to manage LV networks. As the presence of Distribution Energy Resources (DER) increases, a greater insight into LV networks is required to manage load and power quality in real-time as a Distribution Network Service Provider (DNSP).

Distribution and Substation Monitoring objectives must address the challenges of DNSP and managing the two-way power flow of the network by implementing a program of works that caters for the evolution of networks. For example, requirements to operate Voltage Var Control (VVC) and Dynamic Operating Envelope (DOE) schemes will become prevalent in future networks and will need to be standardised to cover the operation of a dynamic distribution network.

To achieve JEN's Asset Management objectives in a changing market, Distribution and Substation monitoring equipment must consider Digital Substation integration and Operational Communications technology. These considerations are reflected in all Sub-asset class strategies.

3.1.3 EARTH FAULT MANAGEMENT

It is a requirement of JEN to achieve high levels of public safety and supply reliability through preventative and corrective maintenance programs which are designed to minimise and or eliminate the risk of fire ignition from the JEN supply networks.

To achieve this requirement, a Rapid Earth Fault Current Limiter (REFCL) strategic Program that supports JEN AMS and objectives has been developed. This Program proposes to implement REFCL technology at substations that either service Bushfire Risk Areas or encounter the worse performing supply reliability levels within JEN.

The REFCL Program realises JEN's strategic objectives as it:

- identifies through engineering analysis, the optimised list of zone substations where an asset management intervention investment provides the highest net benefit, considering risk, performance and cost;
- involves installing REFCLs to address the needs of the identified zone substations (and their distribution feeders), or where a viable and efficient network or non-network solution exists, using this alternative to defer capital expenditure in the program;
- seeks to improve reliability performance for JEN's worst-served customers, by minimising supply interruptions caused by transient phase-to-ground distribution feeder faults in poor reliability areas (including faults that can evolve into multi-phase or permanent faults, triggering secondary damage and upstream clashing);
- seeks to reduce public safety risks associated with distribution feeder faults (including fire-starts, live conductors on ground, and reduced exposure to fault energy impacts); and
- ensures the total lifecycle costs of the risk and investment is minimised for customers and the business, including prioritising sites according to worst reliability performance, highest safety risk and servicing of Hazardous Bushfire Risk Areas.

REFCL technology impacts the Earth Fault Management philosophy of a substation and its connected feeders therefore Sub-Asset Class strategies aligned with Digital Substation objectives should be considered as REFCL technology is deployed.

3.1.4 OPERATIONAL TECHNOLOGY

Operational Technology (OT) plays an important role in achieving JEN Asset Management objectives. Operational technology infrastructure combines advanced communication, sensing and metering infrastructure with existing or new networks to create smart networks.

The continued implementation of an Internet Protocol (IP) based Wide Area Network (WAN) via an optical fibre network at JEN zone substations and key sites (host SCADA, etc) delivers the services required for JEN to carry out its business operations and obligations as a DNSP.

New implementations of Operational Technology use Multi-Protocol Label Switching over IP (IP-MPLS). This provides high speed and high bandwidth capabilities for the SCADA, protection, control and monitoring networks. Implementing IP-MPLS technology allows corporate functions on the same network without adversely affecting the electrical and operational networks as virtualised sub-networks are created to maintain separation between networks.

IP-MPLS also supports existing communications protocols currently in use and the desired IEC 61850 standard that is implemented as part of the Digital substation objective.

Given the reliance Protection, Control and SCADA equipment has on operational technology, achieving all Secondary Plant Asset objectives will need to ensure the following Sub-Asset Class strategies are considered when project works are initiated:

- Communications systems
  - Network devices
  - Multiplexers
  - Communications cabling
  - Multi-Protocol Label Switching (MPLS)
  - Cybersecurity

4 SUB-ASSET CLASS STRATEGIES

The Sub-Asset Class Strategies provide an asset overview and identify the most appropriate strategies and plans for managing the assets over their lifecycles. Each sub-asset class strategy includes information on the asset management practices, including key strategies, options considered and plans that informs expenditure plans and work programs.

Specifically, the Sub-Asset Class Strategies address the following:

- Introduction - Function and Asset Description;
- Asset Profile – Life Expectancy, Age Profile, and Utilisation;
- Performance – Requirements and Assessment;
- Risk – Criticality, Failure Modes, Current Risks, Existing Controls and Future Risks;
- Life Cycle Management – Asset Creation, Asset Operation and Maintenance, Asset Replacement, Disposal and Spares; and
- Asset Information.

4.1 PROTECTION AND CONTROL SYSTEMS

4.1.1 INTRODUCTION

The protection and control equipment (also variously known as Relays or Intelligent Electronic Devices) are designed and configured to detect the presence of network faults and/or other abnormal operating conditions. These devices automatically initiate action to either isolate the faulted network by the opening of appropriate circuit breakers or to correct the abnormal operating condition by initiating some pre-defined control sequence. Protection and control ensure the safety of our staff and the community as correct operation of these devices limits the impact fault have on the stability of JEN and any potential damage to infrastructure.

Protection and control equipment is installed within zone substations and continuously monitors the output of transducers, sensors and instrument transformers (e.g. current transformers and voltage transformers). Protection and control equipment can also be found on the distribution network such as Automatic Circuit Reclosers (ACR) and fuses. These devices on the distribution network are required to be coordinated with zone substation protection and control equipment to ensure the philosophy is applied as intended.

In 2015, JEN commenced incremental implementation of IEC 61850 (consisting of partial station bus for X P&C schemes, at BMS and TMA) as part of achieving Digital substation objectives. IEC 61850 (full station bus for X and Y P&C schemes, plus partial process bus at 66kV level) has been rolled out at PTN and COO, with application of the standard at FW forthcoming.

The type of protection and control equipment applied varies from simple time delayed over-current relays to more complex differential and distance protection schemes depending upon the primary asset being protected or controlled, the type of fault to be detected and other considerations such as speed of fault isolation.

It is critical that every network fault is detected and automatically isolated by the opening of high voltage circuit breakers. This is achieved by correct operation of protection relays. It is a regulatory requirement (Clause C, NER Version 63, Section 5.1.9), as well as inherent to standard design practice in JEN and other utilities, that protection relay schemes are either duplicated or backed up by another relay. This design philosophy reduces the risk of a network fault not being isolated, but often the total time taken to isolate it by backup protection is longer and a greater number of customers are interrupted in isolating the fault. For example, consider a typical feeder protection relay backed up by a bus overcurrent protection relay: failure of the feeder protection relay to detect and isolate a feeder fault will result in the bus overcurrent relay operating and tripping off supply to the entire bus, impacting a larger number of customers than if the feeder relay had been effective.

In cases where both the initial relay scheme and backup scheme fail, then the fault is unlikely to be isolated. Failure of two devices is generally not catered for in design, and the potential for such a situation is mitigated through routine maintenance and monitoring. It is in breach of the Electricity Safety Management Regulations (Part 10, Division 2 of the *Electricity Safety Act 1998*) if substation plant is in-service without protection.

When new protection and control equipment is installed or existing assets are replaced, they are designed and installed in accordance with zone substation Secondary Design Standard (JEN ST 0600) and Protection and Control Settings Manual (ELE AM MA 0003). These standards produce a common proven platform for design, installation and testing, minimising the scope for errors.

This sub-asset class excludes the following:

- Protection and control equipment installed at seven AusNet Services terminal stations that are used to protect JEN sub-transmission lines. This equipment is owned by AusNet Services. Replacement of sub-transmission line protection equipment installed at JEN owned zone substations may also require a like replacement at the remote end by either AusNet Services (in the case of a terminal station line exit) or another distribution business' zone substation (e.g. CitiPower & Powercor).
- Any voice frequency (VF) or other legacy analogue remote trip equipment used for protection signalling between stations. This equipment is maintained and replaced according to the Communication Cabling sub-asset section elsewhere in this ACS. All new digital remote trip schemes will be implemented over JEN owned fibre optic communication channels via multi-function digital line current differential protection relays.
- Protection and control schemes that ship with zone substation transformers such as top oil and winding temperature monitoring, gas protection and cooling control schemes. These schemes form part of the Electricity Primary Plant ACS.
- Protection devices located on the distribution network such as fuses or ACR and kiosk internal protection. These schemes form part of the Electricity Distribution Plant ACS.

4.1.1.1 *Sub-Asset Class Functionality and Types*

Zone substation protection and control equipment can be classified by protection and control functionality, namely:

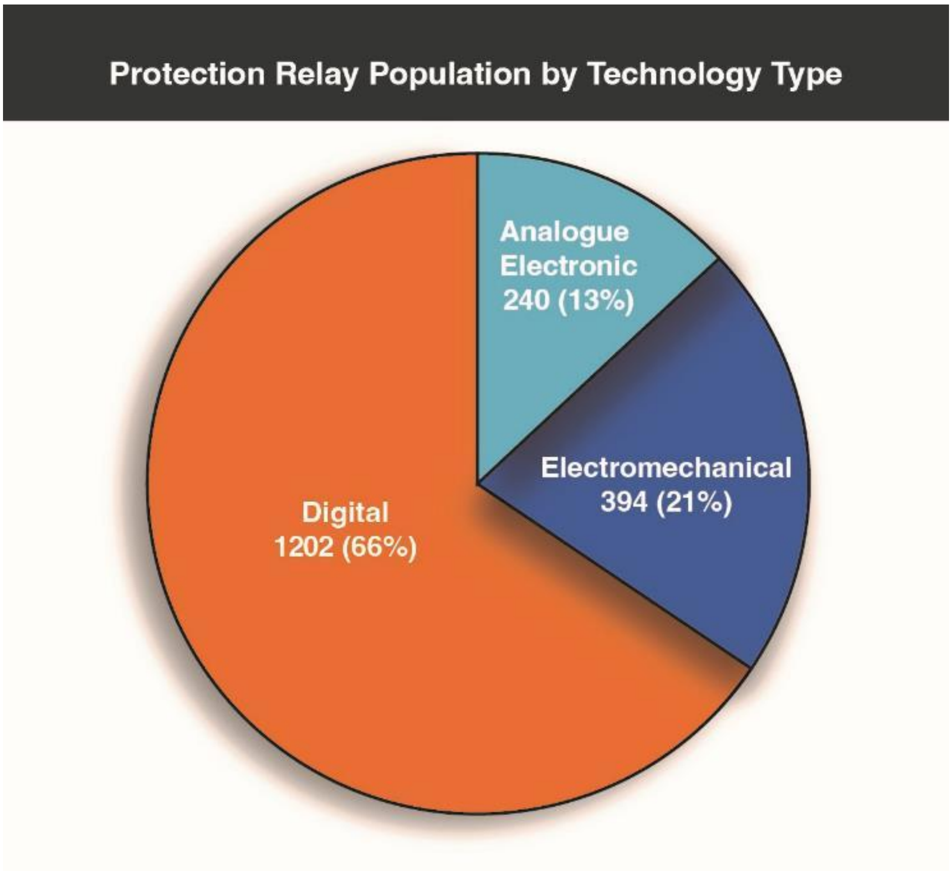
- Protection of feeders, transformers, capacitor banks, busses and lines; or
- Control of circuit breakers, transformer tap-changers for voltage regulation and of capacitor bank switching.

Protection and control technology has evolved and changed significantly over the past 70 years and can be categorised into the following:

- Electro-mechanical (1950-1970 relay generation);
- Analogue electronic (1970-1985); and
- Digital/numeric (1985-Present).

Figure 4–1 shows the relay population on the JEN by the type of relay technology.

Figure 4–1: JEN's relay population by technology type, December 2024



4.1.1.1.1 Electro-mechanical Relays

Electro-mechanical relays represent a mature and reliable technology that has been used extensively for many years in the electricity supply industry both locally and overseas. These relays use electro-mechanical components to provide the operating characteristics of the relay and are typically single function/single phase devices. Examples of this relay type include CDG11, ICM21, RI, PBO, RVL, CAG and VAT. Given their reliance on moving parts, electro-mechanical relays require regular preventative maintenance performed by experienced personnel. Some specific electro-mechanical relays such as the CDG range of inverse time overcurrent relays are still being manufactured today. However, they are no longer being purchased by JEN nor are they widely used within the electricity supply industry. This relay technology has no cost advantage (cost may be higher than the numerical equivalent) and digital relays have superior functional capability.

4.1.1.1.2 Analogue Electronic Relays

Analogue electronic relays are solid state or static relays, that is, there is no armature or other moving element associated with measurement and decision-making process of the device. The response of the relay is developed by electronic component designs without mechanical motion. The first generation in this trend utilised the transistor in discrete electronic component designs. The second generation introduced the Integrated Circuit (IC) and operational amplifiers. Many of these semi-conductor components, particularly in the early relays, are no longer produced. Examples of analogue electronic relays include models RACID and RADHA. This relay technology is now only applied in a few relay types (for example. 2C137 Master Earth Fault relays) and has limited usage into the future and has been superseded by digital relays.

4.1.1.1.3 Digital/numerical Relays

Digital relays are the next step after analogue electronic in the application of electronic technologies. Digital relays where first introduced into the network during the 1990s and provided even greater sensitivity, faster operation, enhanced flexibility, faster reset times, lower VA burden, greater accuracy and reduced size, all at a lower cost. They also offer many other ancillary functions such as programmable control logic, event recording, fault location data, operational metering, circuit breaker control, adaptive settings, remote setting capabilities, peer-to-peer communications and self-monitoring and diagnostic features.

Digital relays sequentially sample and convert the measured AC quantities (voltage and/or current) into digital signals (square wave binary voltages). Logic circuits or a micro-processor then compare the phase relationship of the square waves to make a trip decision. They are principally constructed from sensitive integrated electronic circuits. They usually have self-monitoring features which in turn reduce the need for preventative maintenance as the relay will report automatically when it is faulty. An example of such a relay type is the SPAJ.

Numerical relays are those in which the measured AC quantities are converted into numeric data on which a micro-processor performs mathematical/logical operations to make a trip decision. Application specific algorithms, which replicate various protection and/or control operating characteristics, define the functionality of the relay. Almost all relays marketed today are of numerical technology. Examples of such relay types include the SEL351S, GE L90, GE SR760, SIEMENS 7SD511. Although modern microprocessor based numerical relays are different from the early digital relays in terms of design, functionality and capabilities, they are grouped together for the purpose of this life cycle management plan. Digital and numerical relays incorporate comprehensive self-monitoring routines and therefore require less preventative maintenance than their predecessors, namely analogue electronic and electro-mechanical relays.

There are over 200 unique models of main protection and control equipment in-service across JEN with a total population of approximately 1,836 relays. Approximately 21% (394 relays) of JEN's relay population is remaining electro-mechanical technology. These relays were installed around 30 to 40+ years ago and were mostly imported from countries such as the United Kingdom with some being manufactured locally in Australia including some by the former State Electricity Commission of Victoria (**SECV**). Given their age, very few spare parts are available.

The remaining 79% (1,442 relays) of the population comprising relays is based on electronic technologies, with approximately 13% (240 relays) being analogue electronic relays and 66% (1,202 relays) being digital or numerical electronic relays. Most of these relays have been imported from the United States of America, China, United Kingdom and other European countries including Sweden, Switzerland, Germany and France.

4.1.2 RISK

Protection and control systems are designed to detect the presence of faults or other abnormal operating conditions and to automatically isolate the faulted network by opening appropriate high voltage circuit breakers. Interruptions to customers from faulty protection and control equipment are generally caused by either:

- Failure of the protection relay to act upon a genuine fault; or
- Maloperation of the protection relay under system normal conditions.

Failure or maloperation of protection relays can lead to risks in the following categories:

- Health and safety

  - Severe damage to high voltage apparatus and may also cause an extreme HSE incident to personnel, the community or environment.
- Operational
  - Limits business operations of the electricity distribution network with contingency plans enforced.
- Financial
  - Loss of supply (outages) can result in financial penalties based on frequency of occurrence, duration and number of customers affected.
- Reputation
  - Perception from industry and customer stakeholders can be negative should reliability and safety performance reduce.
- Regulatory
  - Obligations under legislation, regulation, rules and codes may be breached.

Due to the complex nature of implementing protection and control schemes, duplicated or backup protection schemes are designed to detect and isolate faults as quickly and reliably as possible. Furthermore, REFCL implementation adds another layer of complexity as the technology operates under a different protection philosophy and must be integrated such that conventional protection schemes can still be utilised. All protection and control schemes are aimed at mitigating the above risks due to protection failure or maloperation.

4.1.2.1 *Criticality*

The management of asset risk and asset management risk requires assets to be managed in respect to their materiality and criticality. An asset criticality assessment was conducted at the sub-asset class utilising JEN's Asset Criticality Assessment worksheet (ELE-999-PR-RM-003). Results of this assessment can be found in Appendix A. Asset criticality scoring was then used to rank critical assets which have the potential to significantly impact JEN's operational objectives. This helps prioritise implementation of risk mitigation and control measures.

Protection and control sub-asset class has an asset criticality score of AC4 (High) due to the operational and health and safety consequence associated with failures or maloperations. Protection and control equipment criticality (importance) is defined by:

- Impact on supply interruption when a protection fails to clear a genuine fault or mal-operates under system normal;
- Impact on network asset during faults (e.g. Power Transformers, Capacitor Bank, Circuit breakers, etc.) when a protection equipment fails to clear genuine network fault;
- Health and Safety risks associated with the failure of protection and control equipment for a genuine network fault; and
- Impact on compliance requirement with the Electricity Safety Management Regulation and the Victorian Electricity Distribution Code

4.1.2.2 *Failure modes*

Failure of protection and control equipment can appear as either:

- A non-operation, that is, it does not operate when required to do so; or

- An unwanted operation or mal-operation for either an in-zone fault (operated different to intention), out of zone fault or no fault at all.

4.1.2.3 *Current risks*

All risks are identified and managed in JEN's Compliance & Risk System (**OMNIA**).

The risk of protection equipment failing to operate or mal-operating are the two main risks associated with this sub-asset. Salient risks for this sub-asset class are:

- **Faulty protection relay fails to operate and isolate the network fault.** Consequence: 'Major'. Can result in death or serious injury (e.g. permanent disability, multiple hospitalisations, etc.) to personnel or a member of the public within proximity of assets exposed to hazardous voltages/currents due to uncleared fault. An additional consequence is **Fire Start**: potential to start a fire from downed conductors or conductors coming into contact with vegetation;
- **Faulty primary protection relay fails to isolate a network fault causing back up protection scheme to operate.** Consequence: 'Major'. Can result into loss of supply to large numbers of customers (approx. 15,000) for a long duration (approximately 60 minutes) leading to STPIS penalties;
- **Faulty protection relay mal-operates in absence of network fault.** Consequence: 'Major'**.** Can result into loss of supply to large numbers of customers (approx. 15,000) for a long duration (approximately 60 minutes) leading to STPIS penalties; and
- **REFCL technology inadvertently operates.** Consequence: 'Major'. Similarly to above, this can result in serious injury and or loss of supply to large numbers of customers. REFCL technology places operating constraints on distribution assets and the electricity distribution network. For example, only hardened and balanced networks can be protected by a REFCL device.

4.1.2.4 *Existing controls*

There are three existing controls:

- Those detailed in the recommended condition monitoring and maintenance tasks together with initiation of replacement projects for assets determined to be at risk of failure;
- Online Monitoring. Modern secondary equipment employs comprehensive self-monitoring functions and diagnostic features. These relays are capable of reporting back to JEN's Co-ordination Centre via SCADA when it is faulty; and
- Spares. JEN has a comprehensive spares management system in place for protection and control equipment which ensures the availability of healthy and serviceable spares in the event of protection equipment failure.

4.1.2.4.1 Control effectiveness

The three main principles of risk control are maintenance, online monitoring and spare management. These are proven to be highly effective.

Effectiveness of risk controls is informed by the track record of condition-based replacement projects. By comparing identified risks and measuring actual incidents, an assessment of the effectiveness of the existing controls is tabulated.

Table 4-1: Protection and Control Relay Information

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, safety & environment	Protection failure results in environmental damage or injury to personal	Asset Management strategy applied Replacement projects completed	Nil
Regulatory & compliance	Protection failure or mal-operation results in non-compliance notice	Asset Management strategy applied Replacement projects completed	Nil
Financial	Protection failure or mal-operation results in significant unplanned cost	Asset Management strategy applied Replacement projects completed	Nil
Operational	Protection failure results in loss of supply to customer OR Protection mal-operation results in loss of supply to customer	Asset Management strategy applied Replacement projects completed	One (Loss of supply to Coburg when Transformer protection mal-operated)

4.1.2.5 *Future risks*

Emerging risks for this sub-asset class are:

- Cyber Security: Unauthorised access to protection and control equipment could cause service disruption and compromise the protection and control system. Cybersecurity is being addressed at an enterprise level with strategies currently being investigated and considered when Protection and Control equipment is selected;
- Ageing equipment: This means the likelihood of failure or mal-operation increases, necessitating unplanned replacement;
- Deteriorating electro-mechanical relay populations: Online monitoring is not supported, therefore JEN does not immediately know when they fail. Spare parts become unavailable, necessitating unplanned replacement;
- Legacy design principles regarding summation of multiple CT cores: A couple of instances have highlighted legacy differential schemes are unable to stabilise the scheme against CT saturation caused by a through fault. This leads to relay mal-operation and complete loss of the zone substation. Mitigation works are required such as (a) installation of line CT to avoid paralleling multiple CTs outside the relay, (b) retrofitting the existing primary plant (e.g. Transformer or CB) with an adequate number of CT cores to avoid the use of interposing CT's and or avoid extending the Transformer Differential protection to protect the 66kV Bus;
- Non-availability of components for old relay from suppliers/manufacturers: Old relays tend to become unsupported and may necessitate unplanned replacement;
- Expenditure prioritisation: Constraint of funds may cause deferral of replacement programs;
- Damage caused by vandalism: There are increasing evidence of malicious damage to JEN's exposed fibre optic cabling. This can compromise the protection and control system; and
- Adverse network reliability performance: REFCL technology places operating constraints on the electricity distribution network where the protected network is defined by the desired earth fault

detection sensitivity. REFCL operations can lead to isolating the fault from the zone substation (for example the feeder CB). Further works with distribution assets are required to maintain current levels of network reliability when operating at superior earth fault detection levels.

4.1.3 PERFORMANCE

4.1.3.1 *Requirements*

Performance expectations are assessed against the following criteria:

- Operational availability of protection and control system;
- A stable and reliable electricity distribution network; and
- Zero adverse HSE impact.

Performance expectations are achieved through inspection, condition monitoring, preventative and corrective maintenance, condition-based asset replacement as well as monitoring of performance against budgeted targets.

JEN is required to report the number of protection and control equipment failures impacting reliability and/or health and safety to ESV every three months. This does not include relay failures identified during routine maintenance, continuous monitoring or annual inspection.

Protection and control equipment failures do not always result in impact to reliability and/or a HSE issue. There is a regulatory requirement for every protection relay to be either duplicated or backed up by another protection relay to mitigate the risk for its failure.

Performance measures used to monitor the performance of protection and control equipment are:

- 100% operational availability protection and control system. This is measured by recording the protection scheme's 'up time';
- 100% NER compliance with respect to outage repair times (e.g. repair fibre optic cable with 8 hours). This is measured by reviewing field crew Incident Notification documentation; and
- 100% zero HSE incidents.

Protection and control equipment is kept in-service continuously to monitor and detect the presence of network faults and/or other abnormal operation conditions.

4.1.3.2 *Life expectancy*

A protection and control scheme typically comprises of a main relay, associated AC and DC wiring, panel mounted switches, indicators and meters as well as auxiliary relays and other ancillary equipment necessary to provide the full functionality of the scheme. The main relay is the principal component in the scheme and is the most likely element to fail essentially determining the useful life of the protection and control scheme. This approach simplifies the analysis for determining asset life and strategy. Any maintenance or replacement of the main relay also includes all associated equipment necessary to provide the full functionality of the scheme.

Criteria used to determine the life expectancy of a protection and control relay are:

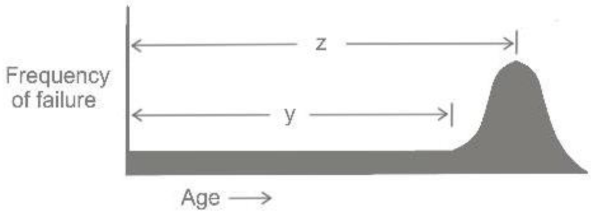
- Relay technology time horizon (e.g. electro-mechanical, analogue electronic, digital);
- Historical data derived from preventative maintenance results and failures/defects;
- Manufacturer's warranty;
- Degree of manufacturer support (repairs, spares, engineering expertise); and
- Industry norms.

The useful life of a relay depends on the type of relay however life expectancy is based on when the relays start exhibiting signs of irreversible deterioration in performance. The following table captured nominal relay life expectancy based on the type of relay technology.

Table 4-2: Nominal Relay Life Expectancy

Relay Technology	Nominal Life Expectancy
Electro-mechanical	40 Years
Analogue electronic	20 Years
Digital/numerical	20 Years

Figure 4–2: Relay life expectancy characterised using Weibull distribution



For a given population of relays of the same age and similar design and construction, the likelihood of failure during the useful life period 'y' is relatively low and assumed to be constant. At an age just beyond the useful life expectancy, the likelihood of failure and therefore the frequency of failure will also increase because of age related deterioration. As the population continues to age, the likelihood of failure is assumed to also increase resulting in a further rise in the frequency of failure. At an age 'z' the frequency of failure begins to reduce due to the reduction in the remaining population (and not due to a decrease in the likelihood of failure).

4.1.3.2.1 Electro-mechanical relays

Our data shows that 40 years is a realistic for electro-mechanical type relays. Manufacturer's estimates have been open ended with many claiming that electro-mechanical relays will continue to operate satisfactorily provided regular preventative maintenance is performed. The existing preventative maintenance cycle is 8 years for this relay type (an industry norm).

Details of electro-mechanical relay failure modes for different relay types are:

- CDG relays have shown significant timing errors that are an indication of the relay losing magnetism; significant timing errors reduce grading margins with upstream or downstream protection relays and greatly increase the risk of unwanted protection operations;
- TJV relays have also been observed to be losing their magnetism thereby adversely affecting their time current characteristic;
- The majority of the PBO relays were replaced, because they had shown significant timing errors. This is an indication of the relay losing magnetism. Significant timing errors reduce grading margins with upstream or downstream protection relays and greatly increase the risk of unwanted protection operations;
- RI relays have a continuously rotating disc and require that the disc bearing be lubricated regularly. The bearing wears, and periodically the disc pivot must be reground and polished to permit reliable timing. Facilities to do this are not available;

- CMG relays have bearings that suffer from stiction (static frication). That is, after a prolonged period of non-operation, a higher than expected current is needed for initial operation, although successive operations will be at the lower current value calibration point;
- DS5, DSF7 and DL4 relays are pilot wire relays in which relays are installed at both ends of a line and connected by a pair of wires (pilots) in a supervisory cable. Although the relays are of an age where continued reliable service is in doubt, the supervisory cables that connect the relay pair have deteriorated and failures are common. Pilot failure can cause both failure to operate for a fault and non-fault conditions. When a pilot failure is detected the relays can be transferred to an alternative pilot circuit through an exhaustive calibration process, however due to previous cable failures alternative circuits are far less likely to be available. Pilot wire relays are installed on all 66 kV lines except where they have already been replaced because of supervisory cable issues by digital current differential relays that operate on fibre optics or other digital bearers; and
- RDW and PCD relays are directional relays that allow overcurrent protection to operate when the current flow is in one direction only. Bearing problems with these relays may cause them to jam so that either an overcurrent operation occurs when not required or no overcurrent operation can occur.

Similar relay defects and performance issues have been observed across the Victorian electricity supply industry. In most instances these defects can be rectified during preventive maintenance (subject to availability of spare parts). However, the ability to rectify such problems during maintenance is becoming increasingly untenable. They have a limited range for mechanical adjustment and once exhausted it is not possible to keep the relay in-service.

4.1.3.2.2 Analogue electronic relays

The electronic components used in this relay technology are susceptible to electrical transients as well as temperature extremes that impact life expectancy. Many components semi-conductors are no longer manufactured. Additionally, age-related drift in component characteristics occur affecting relay measurements. This type of relay also requires an auxiliary DC power supply that is found to be a point of failure, particularly in relays of an older design.

Some analogue electronic relays nearing 20 years in-service age are exhibiting signs of end-of-life deterioration, namely:

- Output contacts on RACID relays fail to open;
- A 2C135 relay failed to operate due to an overheated resistor in one instance; and
- Another 2C135 relay minimum operating setting was found to have drifted.

Low manufacturer support and spare parts availability for analogue electronic relays is a constraint.

4.1.3.2.3 Digital/numerical relays

These relays require an auxiliary DC power supply to provide the relay’s sensitive electronics with the necessary low voltage supply rails (e.g. 5VDC). Auxiliary DC power supplies are known for their relatively poor reliability; in particular the electrolytic capacitors used for filtering the DC output are susceptible to premature failure. In addition, the auxiliary DC power supply also takes the brunt of most electrical disturbances in the zone substation DC supply system. Power supply reliability in relays of newer design appears to be more robust.

Recent discussions with relay manufacturers have provided a level of confidence that life expectancy is 20 years. The average age of this relay type in the JEN network is 11 years with the oldest digital relays being not more than 37 years. This means limited data exists to confirm the useful life expectancy more accurately. Digital relays are not expected to last any longer than the analogue electronic type of relay.

Some manufacturers issue regular service bulletins that notify of known problems in each relay make/model and typically include recommendations to address the problem. Problems in digital relays are typically caused by programming bugs and are usually addressed via a simple firmware upgrade. In rare cases, a hardware upgrade may be necessary. In some instances, the service bulletin does not directly impact the JEN application of the relay and no action is taken. Firmware versions are upgraded if there is a genuine risk to the safe and reliable operation of the protection and/or control scheme that uses the relay.

Earlier generation of digital/numerical relays such as SPAJ 140C, SPAJ 160 and GE SR Series relays have been failing across network recently due to power supply module failures. This has caused JEN to bring forward replacement works at selected zone substations.

Each generation of relay technology has introduced new capabilities and features that have enhanced the flexibility and functionality of the relay. Digital relays are designed with comprehensive self-monitoring and diagnostic systems that are integrated into the zone substation's remote alarm system such that any failure is immediately reported at the JEN Control Room via the SCADA network. This feature greatly reduces the risk of relay non-operation under a genuine network fault condition and avoids the situation of a latent condition persisting until becoming apparent by failure to operate when required. Digital relays are generally designed to be fail-safe, that is, not to operate if the relay detects an internal problem.

Strong manufacturer competition over the last 20 years in a rapidly developing digital technology environment has seen quick advances in processors and RAM capacity leading to an increasing rate of relay obsolescence as manufacturers continue to focus on technology evolution to remain competitive. This has meant that new and modern equipment has a shorter lifecycle compared to analogue and electro-mechanical relays with manufacturer support limited or not available for the particular type of relay, The fast pace of digital technology evolution can also impact spare relay stock requirements and relay setting file compatibility when relays are replaced.

4.1.3.3 *Age profiles*

Table 4-3: Age profile information by relay technology type, 2024

Relay Technology Type	Qty	Life Expectancy	Average age
Electro-mechanical	394	40	46
Analogue electronic	240	20	15
Digital/Numerical	1,202	20	10

As of December 2024, the average age of electro-mechanical relays in JEN is 47 years. Relays of this technology are still being installed in retrofitting cases however at very low numbers. These new relays have simple functionality and operating mechanisms which are technically fit-for-purpose. These installations can limit capital expenditure by avoiding replacements of entire systems. These new relays lower the average age of the installed relays of the electro-mechanical class of relays. Approximately 71% were installed prior to 1980 (i.e. have been in-service for 40+ years).

As of December 2024, the average age of analogue electronic relays in JEN is 16.5 years. Similar to electro-mechanical relays, this technology is still installed in low numbers in retrofitting scenarios. These new relays lower the average age of the installed relays of the analogue electronic class of relays. Approximately 31% of these analogue electronic relays were installed prior to 2006 (i.e. have been in-service for 13+ years).

The average expected operating life of protection and control equipment is around 40 years for electro-mechanical (EM), 20 years for analogue electronic (AE) and digital/numerical (DI) relays. The average age of installed electro-mechanical type relays is 47 years with some relays now approaching 50 years. The average age of analogue electronic type relays is 16.5 years and the average age of digital/numerical relays is 11 years.

Figure 4–3: Electromechanical Relays in service by year of installation, 2024

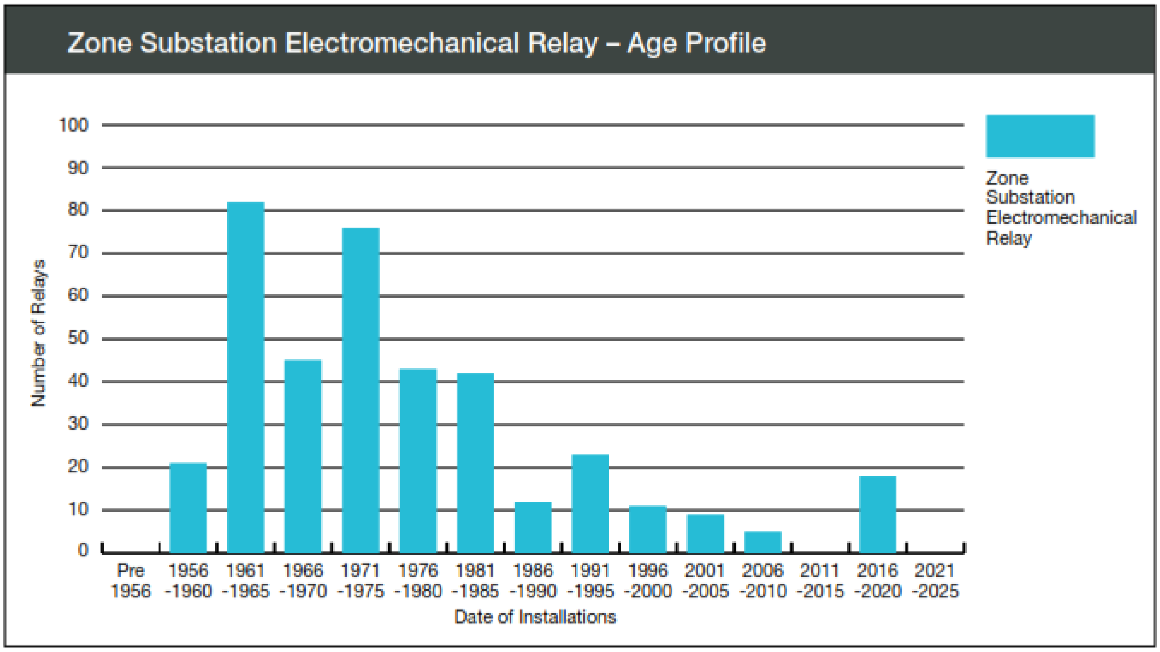


Figure 4–4: Analogue Electronic Relays in service by year of installation, 2024

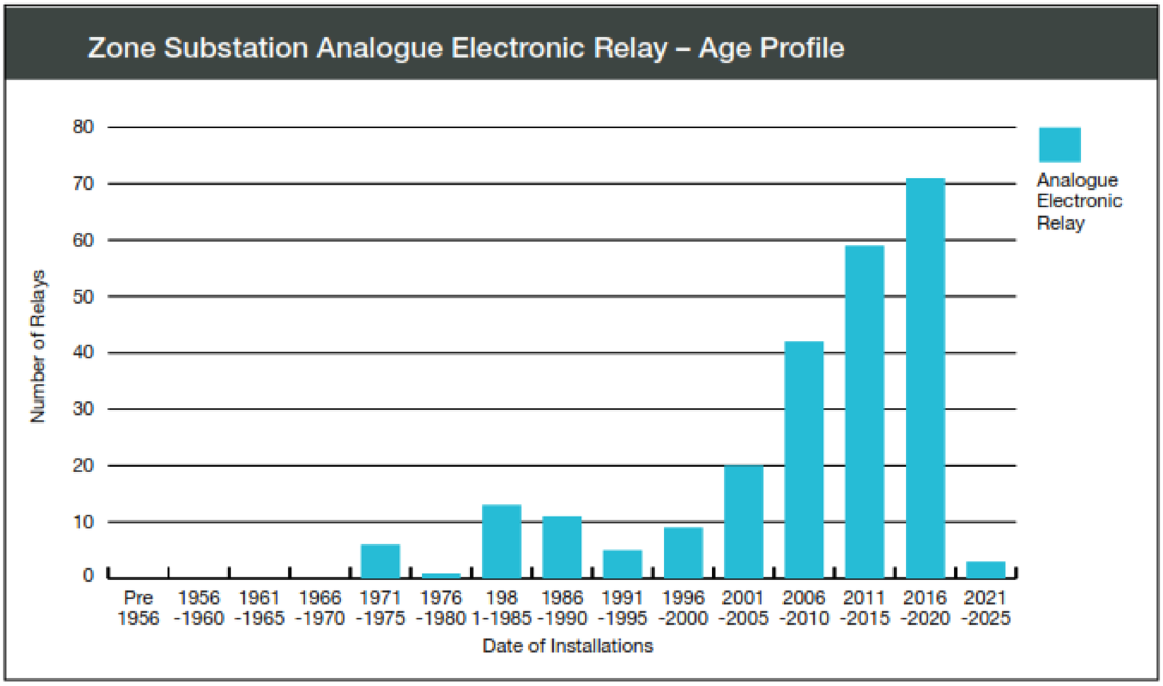
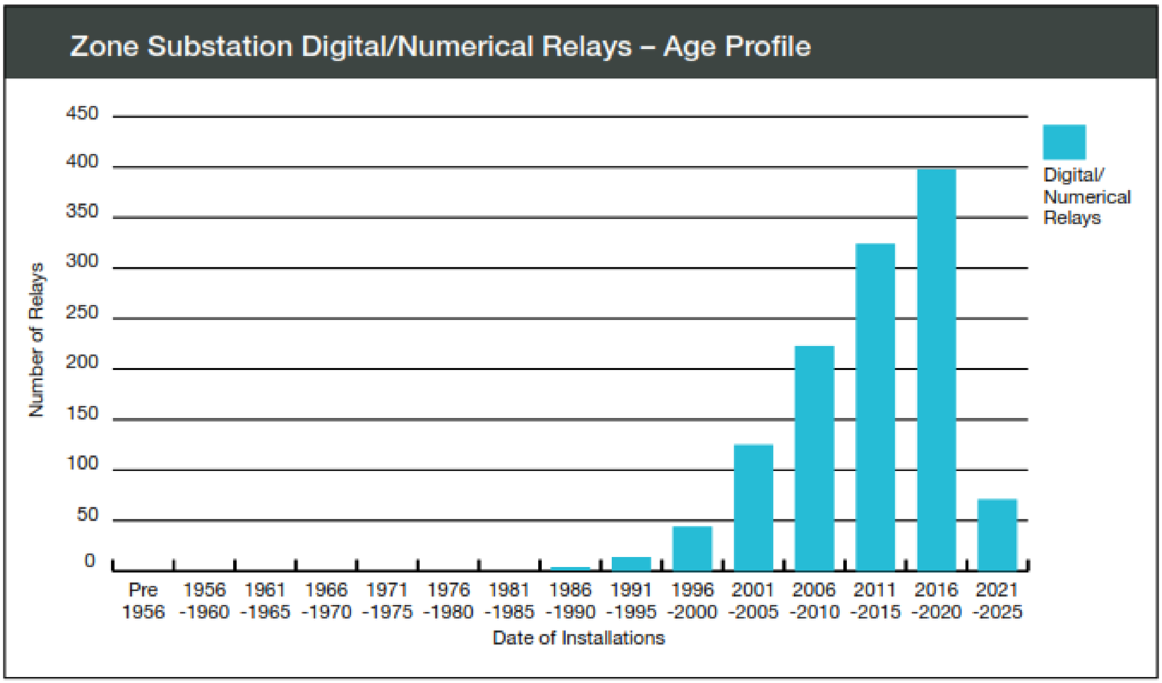


Figure 4–5: Digital Relays in service by year of installation, 2024

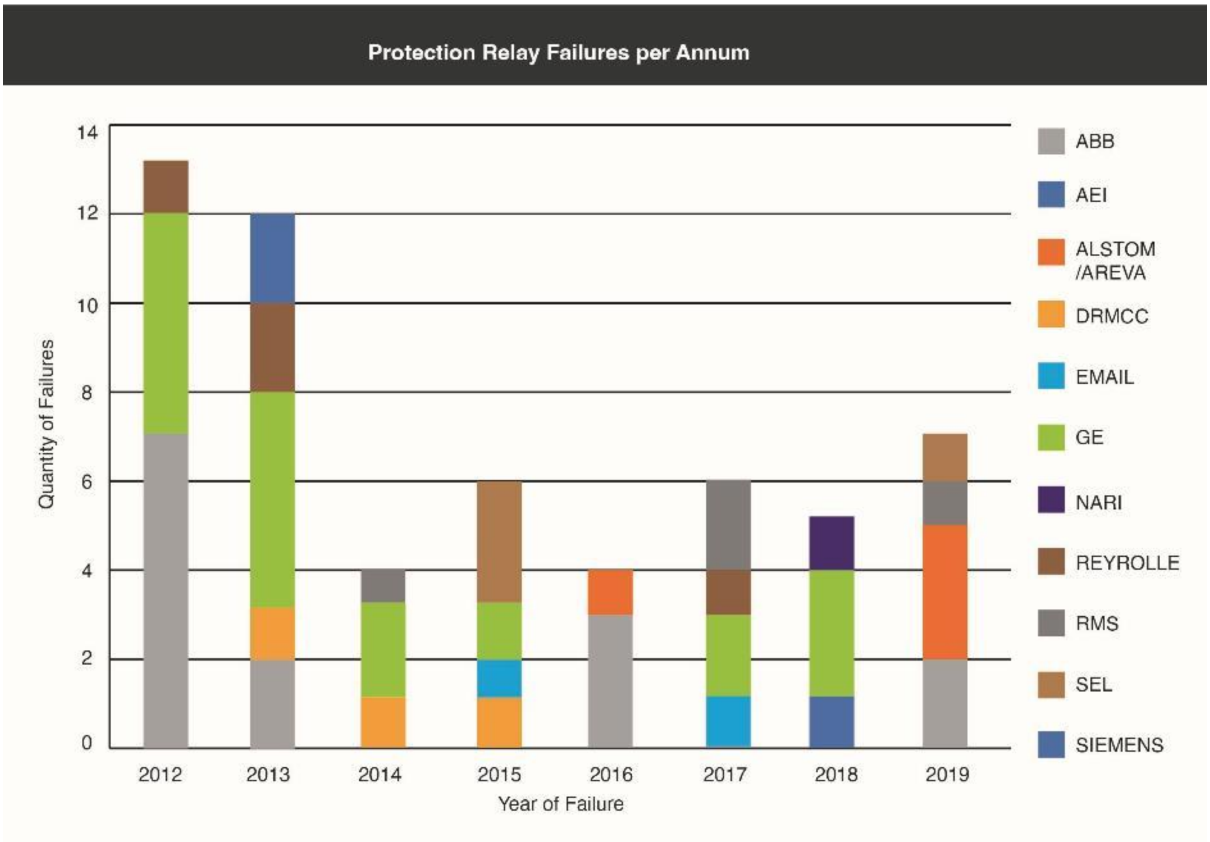


4.1.3.4 *Performance analysis*

When a protection relay fails or mal-operates, root cause analysis is performed. Findings are recorded and reported with associated network impact figures (e.g. SAIDI, SAIFI and MAIFI).

Figure 4–6 provides a snapshot of relay failures over the years.

Figure 4–6: Relay failures by year



There are several issues relating to the reliable operation of zone substation protection and control equipment, namely:

- SPAJ relays;
- GE SR relays;
- Deteriorating electro-mechanical relays; and
- Summation of multiple CT cores on Current Differential Protection Relays.

4.1.3.4.1 SPAJ and GE SR relays

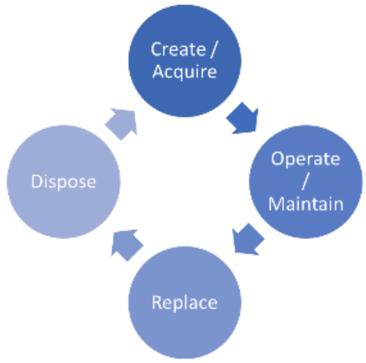
There are ongoing failures of SPAJ relays (ABB SPAJ140C and SPAJ160C) and GE SR relays (SR 750 and SR 760) are early generation digital relays installed on the network in the early 1990's. These relays have been failing recently due to power supply module problems. This problem lies within the manufacturer's design so repair is not a long-term solution. The relays are also out of warranty. These relays have been targeted for replacement.

4.1.3.4.2 Electro-mechanic relays

Many electro-mechanical relays older than 40 years are exhibiting signs of end-of-life deterioration. Recent periodic maintenance on these relays has shown significant timing errors, an indication of weakening in strength of the braking magnet. In most instances these timing errors have been rectified during preventive maintenance. As previously noted, most electro-mechanical relays have a limited mechanical adjustment and once that limit is reached it is not possible to keep the relay in-service. Broadmeadows (BD) zone substation has had its Electro-mechanic relays replaced with Footscray West (FW) substation currently underway. Zone substations North Heidelberg (NH), Coburg North (CN) and Coburg South (CS) with electro-mechanical relay installations have been targeted for relay replacement in the 2026-31 period.

4.1.4 LIFE CYCLE MANAGEMENT

4.1.4.1 *Creation*



Sub-assets in this class are effectively created via acquisition or the deployment of spares. The following scenarios trigger the need to acquire and connect new protection and control equipment:

- As part of new primary plant equipment installations
- Replace aged and deteriorated relays that have reached end of life
- Functional and/or performance improvement driven change
- Change in regulatory requirements
- Customer driven requirements (e.g. sensitive major HV customer, embedded generation, etc.)
- Safety driven network projects (e.g. installation of Neutral Earthing Resistor, installation of Restricted Earth Fault Current Limiter, etc.)
- Specific asset owner requirements

4.1.4.2 *Spares management*

The availability of spare protection and control equipment is a critical element of this sub-asset class strategy. Spare equipment is required in the event of a defect or failure to re-instate full or part functionality of the protection and control scheme in the shortest possible timeframe.

Previously there had been a limited number of spare relays for the relays in-service. System Applications and Products (SAP) has since been utilised to manage secondary equipment spares to address this issue. Additionally, a spares policy has been created to manage critical spares efficiently and effectively.

The objectives of the spares policy are:

- Minimise outage times of the protection and control scheme;
- Minimise network risks associated with any abnormal system arrangement that may be required in response to a protection and control equipment failure, e.g. failed feeder protection scheme would require the feeder load to be transferred away to adjacent feeder(s);
- Avoid or minimise field and engineering resources associated with re-instatement of the defective protection and control scheme;
- Manage re-instatement costs;
- Minimise any impact to customers; and
- Minimise the cost of holding spares, that is, to keep the total spares inventory to a minimum.

Like-for-like replacement of faulty relays is preferred. However, given the large number of different relay models currently in-service across the JEN, it is impractical both from a physical and an economic perspective to hold an identical spare for each unique model of relay.

Table 4-4: Quantities of protection and control spares

Relay Type	Quantities	
	Minimum	Maximum (as % of total population)
Electro-mechanical	2	5% (1 in 20)

Analogue electronic	2	2% (1 in 50)
Digital/numerical	1	2% (1 in 50)

The recommended maximum number of spares is a percentage of the total in-service population of the relay model or aggregate of similar relays models that can be functionally grouped.

The number of spare relays for in-service numerical relays is influenced by the time to repair, involving return of the relay to its offshore manufacturer and availability of sufficient spares in the meantime.

The recommended minimum number of spares are:

- **Case 1 -** The population of a unique relay model is equal to or greater than 20;
- **Case 2 -** The population of a relay grouping or 'family' is equal to or greater than 20;
- **Case 3 -** A spare already exists; and
- **Case 4 -** A special case.

4.1.4.2.1 Case 1

In this case, for example, a spare Schweitzer SEL-0351S6XHD4FB462 type relay would be kept as spare for a population of 20 plus identical SEL-0351S6XHD4FB462 type relays. This approach effectively eliminates the need for costly ad-hoc engineering and field effort during the changeover process as it permits a straightforward like for like replacement. The "0351S6XHD4FB462" identifier is the unique order code for the SEL351S relay used on the JEN network.

4.1.4.2.2 Case 2

Where it is possible to group several unique models of the same relay make into a 'family' such that a higher specification model can be used to replace any model within that family, then the higher specification model shall be used as the spare for that family. For example, an Areva MiCom P127 relay can be used as a spare for itself as well as the P126 and P125 relay models (this being the MiCom P12x family). Likewise, a P123 relay can be used as a spare for itself as well as the P122, P121 and P120 relay models. It is acknowledged with this option that some additional engineering and field effort may be required in the changeover process that would have otherwise been avoided with a true like for like replacement (option A). However, this approach recognises that there are many relay types (in small numbers) that can be grouped into families which will therefore minimise the overall number of unique relay spares required for the JEN.

If in the event a lower specification relay within the family fails and it is replaced with the higher specification spare, then a new spare will be procured to replenish the spare stock but the new spare will again be the higher specification relay. If the faulty lower specification relay can be repaired at a reasonable cost then it should be and then returned to spare stock. Careful management is needed for the possibility that the manufacturer may supply a new relay or return a repaired relay with upgraded (current production) firmware that is incompatible with standard setting files.

4.1.4.2.3 Case 3

If the spare already exists in stock (this will generally apply to the older electro-mechanical type relays). In this instance, the existing relay spare(s) will be retained up to the recommended maximum spares quantity.

4.1.4.2.4 Case 4

It is acknowledged that in some instances an identical spare will be required for a given relay model irrespective of the existing population, this being based upon an assessment of the relay risk profile among other things. In such circumstances a minimum of one identical relay spare will be sourced if it is practical.

As the relays in-service population increases (e.g. due to natural network growth or planned replacement projects), spare inventory shall increase proportionally. Spares will be sourced from one or more of the following sources:

- Purchase from supplier; and
- Free up spare(s) from existing in-service population via a planned relay replacement.

If a spare cannot be sourced, a contingency plan is formulated to:

- Document the best course of action: and
- Implement a proactive replacement plan (or the application of a universal spare).

Protection and control equipment spares are safely stored in a secure and stable environment at Tullamarine. The store location is readily and easily accessible 24 hours 7 days a week for appropriate field staff.

New or recycled equipment is subjected to a quality check before it is put into store. Spares that do not pass the quality check are repaired or disposed of.

A periodic maintenance regime will be applied to all spare protection and control equipment in accordance with manufacturer recommendations to ensure that the spare equipment is serviceable. Relays with auxiliary power supplies (analogue electronic, digital and numerical) are routinely energised (power cycled on/off) every 4 years to prevent dry out of electrolytic capacitors in the power supply circuits.

There is a spares management system in place to ensure that the recommended spares are held in storage. Traditionally, spares have been purchased as part of all capital projects that involve the installation of protection and control equipment. However, adoption of a new spares purchasing policy such that spares are only sourced when required to satisfy the minimum number of spares ensures that spare equipment is not purchased unnecessarily.

An audit of all JEN protection and control spares is carried every 5 years to determine what spares are needed and which spares are no longer required.

Based on the above, the requirement for spares is reflected in the capital expenditure forecast.

4.1.4.3 *Operation and maintenance*

Protection and control equipment maintenance is performed by trained and experienced personnel. The equipment used to test and service JEN's protection and control asset population is regularly inspected, calibrated and certified to the requisite specification and standard.

The results of all secondary plant maintenance tests are recorded and electronically stored for future reference. Test results are captured and collated in a proprietary software package, namely Doble's Protection Suite. Any abnormal performance results are analysed to determine any corrective actions.

This sub-asset maintenance program involves:

- Preventive maintenance; and
- Reactive maintenance.

4.1.4.3.1 Preventative Maintenance

Preventative maintenance consists of continuous monitoring, inspection and testing for each of the relay types. Preventative maintenance tasks common across all relay types consist of:

- Visual inspection of relay for corrosion, rodent and insect damage, water and other physical damage;
- Remove any foreign objects such as excessive dust;
- Clean and adjust output contacts (electro-mechanical and analogue relay types only);
- Confirmation that applied settings reflect settings captured in RESIS;
- Min-op, Timing and Stability tests via secondary current injection (electro-mechanical and analogue relay types only);
- Functional checks of the relay such as trip checks, initiation of reclose and CB fail, targets, annunciations and alarms;
- Re-calibrate relays as required;
- Check inter-relay communications by assessing pilot wire on-loads or communication errors;
- Visual inspection of all scheme wiring, terminals, test links, panel mounted switches & indicating lights etc. Including checking tightness of all connections;
- Check insulation resistance of all wiring and cabling to earth and between electrically separate circuits;
- Confirm readability of labelling and clean or replace as required; and
- On-load tests to verify that equipment transformer (CTs and VTs) and other measuring transducers are providing the correct signals to the relay

Preventative maintenance tasks specific to **electro-mechanical relays** consists of:

- Check for setting drift by comparison with previous maintenance results;
- Re-calibrate relays as required;

Preventative maintenance tasks specific to **digital/numerical relays** consists of:

- Replace relay battery (if fitted) in accordance with manufacturers recommendations;
- Check, review and download all event and disturbance records;
- Confirm operation of relay watch-dog alarm and check receipt of station relay fail alarm at the Co-ordination Centre via SCADA.

Digital/numerical relays are designed to be essentially maintenance free with many of their internal operations being automatically checked by self-monitoring circuitry within the relay. Repeatability without settings drift is an inherent benefit of digital technologies and therefore traditional maintenance tasks such as Min-op, Timing and Stability tests via secondary current injection are not required for this relay type.

Zone substation secondary equipment, including protection and control equipment, is audited annually by the Secondary Plant team. Secondary equipment audit consists of:

- Visual inspection of all secondary equipment for cleanliness; and
- Visual inspection of all secondary wiring, terminals, test links, panel mounted switches & indication lights.

The aim is to minimise preventative maintenance as far as practicable. Maintenance intervals have been aligned with current industry standards. Maintenance requirements have been customised depending upon the relay type, condition of the relay and other factors including the relay age profile. Once maintained, it is assumed that the protection and control equipment will perform reliably at least up until the time that it is next maintained.

If a particular type or family of relay begins to exhibit symptoms of performance degradation, then that relay population will be more closely monitored. This may require an increase in the preventative maintenance frequency. The maintenance tasks may also be customised accordingly to address a specific issue or multiple issues.

Furthermore, if deteriorated protection and control equipment is not replaced at its nominal end of useful life, any known issues with the relay may require reduced intervals of preventative maintenance. For example, an increased rate of drift in a measurement characteristic can be addressed by more frequent recalibration. It is also acknowledged that the risk of relay failure may increase because of over maintenance.

Routine preventative maintenance is performed on protection and control equipment at a nominal 8-year interval excluding sub-transmission line protection schemes. Maintenance on sub-transmission line protection needs to be coordinated with AusNet Services. It is a requirement to maintain all 66kV line protection equipment every three years due to regulatory requirements imposed on the transmission business.

Table 4-5: Preventative maintenance intervals

Protection Scheme	Maintenance Cycle
66kV Line Protection Scheme (Line Differential and Pilot Wire Schemes)	Once every 3 years
All other Protection Schemes	Once every 8 years

Preventative maintenance plans are held in SAP and regularly reviewed to accommodate any planned relay replacement program. This ensures that maintenance is not unnecessarily performed on relays due for replacement

4.1.4.3.2 Reactive Maintenance

Protection and control equipment faults are typically identified after an investigation arising from an abnormal operation or lack of operation. They may also be identified during preventative maintenance or via some form of health condition monitoring with an alarm received in the Co-ordination Centre via SCADA. Faults are urgently addressed as they represent an issue or problem that may impact the performance and/or intended operation of the equipment.

Reactive maintenance consists of:

- Repair within 24 hours; and
- Replacement (with a spare) within 24 hours.

4.1.4.4 *Replacement/disposal*

Generally, there are three maintenance options available for life cycle management of this sub-asset which are:

- Run to failure (reactive);
- Schedule-based replacement (age-based); and
- Condition-based replacement (the most cost effective).

4.1.4.4.1 Run to failure

Run to failure means replacement occurs reactively upon failure (irrespective of age or condition). This option is not desirable because it would result in numerous unwanted failures potentially adversely impacting business operations and would conflict with operating at the required robust level of protection. Resultant ad-hoc replacement would require unplanned primary plant outages and reduce spare relay stock. Depending on spares stock levels, these spares could be exhausted after a few failures, with repair or purchase of older relays adding further risk if the spares are long lead items or no longer available. In that event, modern equivalent relays would need to be installed on a piecemeal basis resulting in higher design and installation costs than the alternative two options.

4.1.4.4.2 Schedule-based replacement

This option proposes to replace protection and control equipment at the end of design/product life in a controlled manner. However, to keep the asset in-service near the end of its design/product life may lead to a higher risk profile. To assist in managing this risk, a larger stock of spare relays and/or a repair facility is required.

4.1.4.4.3 Condition based replacement

This option represents the best value because it precludes the ‘run to failure’ option and improves on the ‘schedule-based replacement’ option. In addition to age, incorporating condition monitoring of the asset facilitates achieving an optimal trade-off between capital expenditure and operating expenditure. Some assets are easier to monitor than others, for example:

- Modern digital/numerical relays are designed with comprehensive self-monitoring and diagnostic systems which are integrated into the zone substation’s remote alarm system and any failures are immediately reported to the JEN Co-ordination Centre via the SCADA network; and
- Legacy electro-mechanical relays do not have self-monitoring features. But these relays are monitored via an annual zone substation inspection program and a comprehensive routine maintenance program. Therefore, a sudden failure of these relays is unlikely.

Other factors that contribute to the replacement of protection and control equipment are:

- functional and/or performance improvement driven change;
- changes in regulatory requirements;
- customer driven requirements (e.g. sensitive major HV customers);
- demand and/or performance driven network projects (e.g. transformer project, installation of neutral earthing resistor); and
- specific asset owner requirements.

The diversity in relay types used across JEN reflects the different design philosophies and purchasing practices employed in the past. The evolution of relay technology over the past 40 years is also a contributing factor to this diversity. For more efficient management of these assets into the future, it is desirable to reduce the number of unique relay models in-service across the network. To facilitate this longer-term objective, significant work on the development of secondary design standards continues which includes establishing a short list of preferred relay makes and models.

The replacement strategy applied to protection and control equipment is principally condition based using available asset data. Due to the critical nature of this equipment, the age of a relay plays a key role in determining the replacement as protection equipment should not be ‘run to failure’. The key criterion used to determine the replacement age is the nominal ‘useful life’ for each type of relay technology. Other criteria are spares availability, realistic repair expectations, orphan relays and maintenance workforce availability.

From a capital expenditure point of view, there are two condition-based replacement choices:

- Fragmented replacement; and
- Bulk replacement.

4.1.4.4.4 Condition-based replacement - Fragmented

Fragmented replacement would see the replacement of specific makes and models of protection and control equipment, that is, only those relays that are not fit for service based on condition or exhibiting symptoms of age-related deterioration. This gradual replacement of protection and control equipment within a zone substation may appear cost effective but it is not economic in the long term. A gradual relay replacement leads to variations in design and configuration settings in the exact type of relay supplied. Moreover, piecemeal replacement is expensive and not considered as a prudent asset management practice. An exception would be in having orphan or maintenance intensive relays eliminated.

Protection and control equipment is highly integrated with other components within the station including auxiliary supplies and primary plant equipment. Direct relay replacement may not be possible due to lack of spare relays or the inability to purchase new relays of an obsolescent type. Replacement with a new relay of a different type may be difficult and often impractical as it may affect other parts of the zone substation design. Most often sub-optimal designs are required to integrate new technology hardware into ageing legacy designs.

This approach is not an efficient use of design and field resources as they need to keep re-visiting the same site as each replacement project is identified. Furthermore, this approach does not eliminate the risk of condition/age related protection and control equipment failures, align with asset class objectives and is therefore considered unacceptable.

4.1.4.4.5 Condition-based replacement - Bulk at nominal end of life

As mentioned above, piecemeal replacement of deteriorated protection and control equipment may appear economic in the short term, but it is not considered a prudent approach because of the resultant variations in design and installation standards, management of station drawings and variations in relay type, firmware and hardware versions. A time-based strategy of bulk relay replacement at the assessed end of life is therefore preferred and has been adopted in this ACS. This approach is consistent with other electricity supply industry businesses and is considered good industry practice. Most of the protection and control equipment installed within JEN zone substations have a similar age profile supporting a bulk replacement approach.

The benefits of bulk relay replacement approach are:

- A significant reduction in overall project delivery cost due to a larger volume of work delivered at the same time. Replacement of deteriorated relays on a piece-meal basis is resource intensive and not cost efficient;
- Realise the benefits offered by the latest relay technology through a more holistic and integrated design. Like-for-like replacement is no longer practical or desirable as modern relays are multifunction devices allowing for many legacy (single function) relays to be replaced by a single package without additional cost. Another example is the ability to implement peer-to-peer communications between relays and the station RTU, thereby minimising the amount of hardwiring within the station;
- Facilitates the transition to new secondary design standards that achieve digital substation objectives and future standards such as IEC 61850;
- Avoids complicated interfaces between new and legacy designs;

- Reduces the risk of unwanted protection operations during site works that would result in the loss of supply to customers;
- Simplifies the replacement of wiring, panels, cubicles, cabling, instrumentation and other interface equipment associated with the aged protection and/or control scheme;
- Improvements in construction documentation i.e. engineering drawings;
- Occupational health & safety considerations e.g. many older zone substations have relays mounted on insulated panels made from an asbestos reinforced material. Restrictions on the cutting and drilling of holes in these asbestos panels makes piece-meal relay replacement very difficult, expensive and impractical;
- Facilitates simpler and more cost-efficient and effective life cycle management of the assets. Bulk replacement will prepare the zone substation for a similar bulk replacement in the future. This will ensure JEN is well positioned to take full advantage of new technological advancements as they develop in the future; and
- Eliminates risk of unwanted age-related protection and control equipment failures as the aged equipment is renewed (replaced) at end of life.

Replacing legacy electro-mechanical and analogue electronic relays with modern digital/numerical relays reduces preventative maintenance requirements because the newer digital relays are virtually immune from settings drift. In addition, digital/numerical relays include comprehensive self-monitoring functions so they can alarm for minor and major problems in real time. This reduces the risk of non-operation and unwanted operations of the relay failure by not leaving a relay in-service should internal problems occur. In the absence of comprehensive self-monitoring, the older relays carry the risk of failure without notice within the maintenance cycle period risking the network. Other benefits can be realised by replacing end of life protection and control equipment with modern digital relays such as:

- the provision of detailed event records;
- fault waveform capture capability;
- user definable protection characteristics;
- programmable logic;
- wider setting ranges;
- an ability to integrate with host SCADA using standard serial communications protocols such as DNP3 and IEC 61850;
- remote access capabilities;
- significantly less wiring; and
- smaller footprint due to the integration of many functions into the one relay.

The replacement of condition and aged-based protection and control equipment has been aligned with the planned replacement of high voltage plant and equipment at the zone substation wherever possible. This may involve the installation of new power transformers or high voltage switchgear, subject to a cost-benefit analysis. The alignment of asset replacement activities maximises the technical engineering benefits afforded by an integrated solution and minimises the project delivery costs.

Any faulty or decommissioned equipment is disposed of accordingly by a certified recycling company in accordance with JEN's Environment Policy (JEM PO 0397).

Relay replacement projects contend for inclusion in the capital works program. Business case proposals compete for priority in JEN's capital expenditure planning.

JEN looks at the sub-asset class capital expenditure and operating expenditure proposals considering the consequences of not undertaking proposed works in line with the following table.

Table 4-6: Sub-asset Class strategic drivers

Strategic Driver	Risk/opportunity Description	Consequence
Asset integrity	Failure of protection equipment	Increase in Expected Unserved Energy to customers (EUSE) Negative publicity that impacts the brand or confidence of stakeholders (e.g. HV customers) Loss of supply to large number of JEN customers for an extended period Loss of supply to major HV customers (e.g. airports, hospitals, factories, etc.) Major damage to zone substation primary plant (e.g. Power Transformer, Circuit Breakers, Capacitor Banks, conductors/cables, etc.)
Safety, health and environment	Failure of protection equipment during fault scenario	Serious injury Fatality

Historical capital expenditure and operating expenditure performance help inform expectations about future programs of work. JEN's relay population of electro-mechanical relays is approximately 22% and is nearing, or have exceeded, their design/product lifetime.

Recent failures have also shown that the condition of a number of relay models (e.g. SPAJ and GE SR series) have a known fault. As a result, beginning in 2016, replacement of those relays have been prioritised in ongoing project (until 2031).

Capital expenditure X information about protection and control equipment proposed for replacement to 2031 is tabulated below. The estimated replacement timeframe is subject to adjustment depending upon the need to undertake other associated works at a particular zone substation to achieve resource efficiency and minimise any disruption to electricity supply.

Table 4-7: Protection and control relay replacement Capital Expenditure

Location	Year	Reasons for replacement	Comments
FW	2025	Relay replacement, modular building approach, as part of FW Redevelopment project	
NH/NEI/ TTS	2026	Mitigate Risks Associated with the existing 66kV line Pilot Wire protection scheme.	To be coordinated with 66kV NEI loop augmentation and NELP operational supply projects
CN	2028	Mitigate Risks Associated with Deteriorated Relays - CN	New building is required at CN to facilitate relay replacement. To be completed as part of CN redevelopment project.
CS	2030	Mitigate Risks Associated with Deteriorated Relays - CS	To be completed as part of CS redevelopment project

Location	Year	Reasons for replacement	Comments
NH	2032	Mitigate Risks Associated with Deteriorated Relays - NH	To be completed as part of NH redevelopment project
NS	2032	Mitigate Risks Associated with Deteriorated Relays – NS. Serious concerns with the GE SR series relays.	Replace all outstanding relays at NS which were not replaced as part of the NS Transformer replacement project in 2017.
NT	2032	Upgrade NT relays - DRMCC replacement • VVC AVR Projects	Align with Primary plant replacement project (transformers and switchgear) at NT.
TH	2032	Replace TH relays (FLISR enable) and DC system • Replace all relays at TH	Align with Primary plant replacement project (switchgear) at TH.

4.1.5 FUTURE IMPROVEMENTS

Protection and control equipment has proved reliable as reflected by the low failure rates. However, as detailed earlier, certain electro-mechanical and analogue electronic relay types are exhibiting performance issues, most notably at or near their deemed useful life expectancy. In addition, early generation digital relays are also failing across the network due to issues with their power supply modules.

The asset register for all main secondary equipment including protection and control equipment installed in the JEN electricity network is captured in the asset management record system. As part of this sub-asset class strategy revision, the Equipment Database was reviewed for all protection and control equipment and sub-asset information was updated as required.

To better manage the relay population, a relatively simple and unique material equipment ID is being evaluated for each unique relay model in use on the JEN network.

Prioritisation of relay replacement projects considers data on relay defects, failure rates and the useful life of the rest of the secondary plant assets. An effective and efficient defect database is being updated to improve the accuracy of this critical input data into the asset class decision making.

To address emerging inherent risks of operating REFCL protected networks, works are required to better integrate REFCL technology with distribution assets such as ACRs and fuses. Such works to maintain or improve network reliability will require research and development activities involving installation and testing of new age ACRs compatible with resonant earthing philosophies.

4.2 DC SUPPLY SYSTEMS

4.2.1 INTRODUCTION

Direct Current (DC) systems supply secondary equipment in zone substations, customer substations and switching stations. Accordingly, the DC supply system is pivotal to the safe and reliable operation of zone substations and the connected high voltage distribution network under both normal and abnormal operating conditions.

The main components of DC supply systems are the battery bank and the charger (rectifier) with DC distribution boards and cables considered auxiliary items to the DC system. Rectifiers are classified as Type 1 in accordance with AS4044-1992 as they not only charge and maintain charge of batteries but also provide primary power to the DC system. If AC power supplying the rectifiers fail, the batteries will continue to supply the DC system load from all the secondary equipment connected. The battery bank must not be allowed to discharge beyond its rated design capacity as this will invariably compromise the reliable operation of zone substation protection and control equipment and potentially damage the batteries permanently. The battery bank cannot be switched out of service without the zone substation being shut down. This is not desirable and procedures are in place for safely replacing faulty batteries while the battery bank remains in-service.

DC supply systems are supported by cost efficient and effective maintenance, replacement and augmentation programs. JEN operates and maintains 240V, 110V, 50V and 24V DC Supply Systems across 28 zone substations, 5 customer substations and one switching station.

The scope of this sub-class asset strategy is limited to the battery banks and chargers only. Further, it excludes any DC Supply Systems installed in outdoor equipment (such as ACRs) and AusNet Services' terminal stations.

Two types of batteries are deployed within JEN's electricity distribution network:

- Flooded, or vented lead acid (VLA); and
- Sealed, or valve regulated lead acid (VRLA).

Table 4-8: Installed Battery Banks and Chargers

Substation	Description	Year of Manufacture	Manufacturer	Type
AW (Airport West)	240V Battery – X Strings 1 & 2	2017	Century Yuasa	VRLA
	240V Battery – Y Strings 1 & 2	2017	Century Yuasa	VRLA
	240V Battery Charger - X	2017	Century Yuasa	
	240V Battery Charger - Y	2017	Century Yuasa	
BD (Broadmeadows)	240V Battery – X Strings 1 & 2	2019	Century Yuasa	VRLA
	240V Battery – Y Strings 1 & 2	2019	Century Yuasa	VRLA
	240V Battery Charger - X	2019	Century Yuasa	
	240V Battery Charger - Y	2019	Century Yuasa	
BMS (Broadmeadows South)	110V Battery - X	2015	Century Yuasa	VRLA
	110V Battery - Y	2015	Century Yuasa	VRLA
	110V Battery Charger - X	2015	Century Yuasa	
	110V Battery Charger - Y	2015	Century Yuasa	
BY (Braybrook)	110V Battery - Control	2019	Hoppecke	Flooded

Substation	Description	Year of Manufacture	Manufacturer	Type
	50V Battery - Communications	2019	Hoppecke	Flooded
	24V Battery - Communications	2019	Hoppecke	Flooded
	110V Battery Charger - Control	2019	Century Yuasa	
	50V Battery Charger - Communications	2006	Brodribb	
	24V Battery Charger - Communications	2019	Century Yuasa	
CN (Coburg North)	240V Battery - Control	2006	Hoppecke	Flooded
	24V Battery - Communications	2007	Hoppecke	Flooded
	50V Battery - Control	2007	Hoppecke	Flooded
	240V Battery Charger - Control	2003	Brodribb	
	24V Battery Charger - Communications	1980	Westinghouse	
	50V Battery Charger - Control	1992	Brodribb	
	240V Battery Bank - Spare	2012	Hoppecke	Flooded
	240V Battery Bank Charger - Spare	2012	Brodribb	
COO (Coolaroo)	110V Battery - X	2022	Century Yuasa	VRLA
	110V Battery - Y	2022	Century Yuasa	VRLA
	110V Battery Charger - X	2022	Century Yuasa	Rectifier
	110V Battery Charger - Y	2022	Century Yuasa	Rectifier
	110V Battery – Control (Spare)	2006	Hoppecke	Flooded
	50V Battery – Control (Spare)	2006	Hoppecke	Flooded
	50V Battery – Communications (Spare)	2006	Hoppecke	Flooded
	110V Battery Charger – Control (Spare)	2006	Amp Control	
	50V Battery Charger - Control (Spare)	2006	Amp Control	
	50V Battery Charger – Communications (Spare)	2006	Amp Control	
CS (Coburg South)	240V Battery - Control	2019	Hoppecke	Flooded
	24V Battery - Communications	2019	Hoppecke	Flooded
	50V Battery - Control	2019	Hoppecke	Flooded
	240V Battery Charger - Control	2003	Brodribb	
	24V Battery Charger - Communications	2016	Brodribb	
	50V Battery Charger - Control	2005	Brodribb	
EP (East Preston)	240V Battery - Control	2017	Hoppecke	Flooded

Substation	Description	Year of Manufacture	Manufacturer	Type
	24V Battery - Communications	2017	Hoppecke	Flooded
	50V Battery - Control	2017	Hoppecke	Flooded
	240V Battery Charger - Control	2015	Battery Systems Australia	
	24V Battery Charger - Communications	2003	Battery Systems Australia	
	50V Battery Charger - Control	2003	Intelpower	
EPN (East Preston New)	110V Battery – X Strings 1 & 2	2015	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2015	Century Yuasa	VRLA
	110V Battery Charger - X	2015	Century Yuasa	
	110V Battery Charger - Y	2015	Century Yuasa	
ES (Essendon)	240V Battery - X	2019	Century Yuasa	VRLA
	240V Battery - Y	2019	Century Yuasa	VRLA
	240V Battery Charger - X	2019	Century Yuasa	
	240V Battery Charger - Y	2019	Century Yuasa	
FE (Footscray East)	240V Battery - X	2021	Century Yuasa	VRLA
	240V Battery - Y	2021	Century Yuasa	VRLA
	240V Battery Charger - X	2021	Century Yuasa	
	240V Battery Charger - Y	2021	Century Yuasa	
FF (Fairfield)	110V Battery – X Strings 1 & 2	2019	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2019	Century Yuasa	VRLA
	110V Battery Charger - X	2019	Century Yuasa	
	110V Battery Charger - Y	2019	Century Yuasa	
FT (Flemington)	110V Battery – X Strings 1 & 2	2018	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2018	Century Yuasa	VRLA
	110V Battery Charger - X	2018	Century Yuasa	
	110V Battery Charger - Y	2018	Century Yuasa	
FW (Footscray West)	240V Battery - Control	2006	Hoppecke	Flooded
	24V Battery - Communications	2012	Hoppecke	Flooded
	50V Battery - Control	2006	Hoppecke	Flooded
	240V Battery Charger - Control	2006	Brodribb	
	24V Battery Charger - Communications	2006	Brodribb	
	50V Battery Charger - Control	2006	Brodribb	
HB (Heidelberg)	110V Battery – X Strings 1 & 2	2023	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2023	Century Yuasa	VRLA
	110V Battery Charger - X	2023	Century Yuasa	

Substation	Description	Year of Manufacture	Manufacturer	Type
	110V Battery Charger - Y	2023	Century Yuasa	
MAT (Melbourne Airport)	110V Battery – X Strings 1 & 2	2016	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2016	Century Yuasa	VRLA
	110V Battery Charger - X	2016	Century Yuasa	
	110V Battery Charger - Y	2016	Century Yuasa	
NEI (Nilsen Electrical Industries)	120V Battery	2008	Hoppecke	Flooded
	24V Battery	2008	Hoppecke	Flooded
	120V Battery Charger	1986	Dimtronics	
	24V Battery Charger	1986	Dimtronics	
NEL (North East Link)	110V Battery – X Strings 1 & 2	2022	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2022	Century Yuasa	VRLA
	110V Battery Charger - X	2022	Century Yuasa	
	110V Battery Charger - Y	2022	Century Yuasa	
NH (North Heidelberg)	240V Battery - Control	2017	Hoppecke	Flooded
	24V Battery - Communications	2017	Hoppecke	Flooded
	50V Battery - Control	2017	Hoppecke	Flooded
	240V Battery Charger - Control	2007	Brodribb	
	24V Battery Charger - Communications	2016	Intelpower	
	50V Battery Charger - Control	2016	Intelpower	
NS (North Essendon)	110V Battery – X Strings 1 & 2 & 3	2017	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2 & 3	2017	Century Yuasa	VRLA
	110V Battery Charger - X	2017	Century Yuasa	
	110V Battery Charger - Y	2017	Century Yuasa	
NT (Newport)	240V Battery - Control	2022	Century Yuasa	VRLA
	50V Battery - Control	2022	Century Yuasa	VRLA
	240V Battery Charger - Control	2007	Brodribb	
	50V Battery Charger - Control	2007	Brodribb	
PTN (Preston)	110V Battery - X	2019	Century Yuasa	VRLA
	110V Battery - Y	2019	Century Yuasa	VRLA
	110V Battery Charger - X	2019	Century Yuasa	
	110V Battery Charger - Y	2019	Century Yuasa	
PV (Pascoe Vale)	110V Battery - Control Strings 1 & 2	2022	Century Yuasa	VRLA
	110V Battery Charger - Control	2011	Brodribb	

Substation	Description	Year of Manufacture	Manufacturer	Type
	12V Battery - Control (Spare)	2021	Hoppecke	
	240V Battery - (Spare)	2016	Intelpower	VRLA
	240V Battery Charger - (Spare)	2016	Intelpower	
SBY (Sunbury)	110V Battery – X Strings 1 & 2	2018	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2018	Century Yuasa	VRLA
	110V Battery Charger - X	2018	Century Yuasa	
	110V Battery Charger - Y	2018	Century Yuasa	
SHM (Sydenham)	110V Battery - Control	2022	Century Yuasa	VRLA
	50V Battery - Control	2022	Century Yuasa	VRLA
	50V Battery - Communications	2022	Century Yuasa	VRLA
	110V Battery Charger - Control	2007	Brodribb	
	50V Battery Charger - Control	2007	Brodribb	
	50V Battery Charger - Communications	2007	Brodribb	
SSS (Somerton Switching Station)	125V Battery - Control	2016	Century Yuasa	VRLA
	50V Battery - Communications	2016	Century Yuasa	VRLA
	50V Battery - SCADA	2016	Century Yuasa	VRLA
	125V Battery Charger - Control	2001	Amp Control	
	50V Battery Charger - Communications	2001	Amp Control	
	50V Battery Charger - SCADA	2001	Amp Control	
ST (Somerton)	250V Battery - Control	2008	Hoppecke	Flooded
	50V Battery - Control	2008	Hoppecke	Flooded
	50V Battery - Communications	2008	Hoppecke	Flooded
	250V Battery Charger - Control	2005	Brodribb	
	50V Battery Charger - Control	2008	Brodribb	
	50V Battery Charger - Communications	2008	Brodribb	
TH (Tottenham)	240V Battery - Control	2008	Hoppecke	Flooded
	50V Battery - Control	2008	Hoppecke	Flooded
	50V Battery - Communications	2008	Hoppecke	Flooded
	240V Battery Charger - Control	2008	Brodribb	
	50V Battery Charger - Control	2008	Brodribb	
	50V Battery Charger - Communications	2003	Brodribb	
TMA (Tullamarine Airport)	110V Battery - X	2015	Century Yuasa	VRLA
	110V Battery - Y	2015	Century Yuasa	VRLA

Substation	Description	Year of Manufacture	Manufacturer	Type
	110V Battery Charger - X	2015	Century Yuasa	
	110V Battery Charger - Y	2015	Century Yuasa	
VCO (Visy Board)	120V Battery - Control	2008	Hoppecke	Flooded
	24V Battery - Clean	2008	Hoppecke	Flooded
	24V Battery - Dirty	2008	Hoppecke	Flooded
	120V Battery Charger - Control	2022	Century Yuasa	
	24V Battery Charger - Clean	2022	Century Yuasa	
	24V Battery Charger - Dirty	2022	Century Yuasa	
WGT (West Gate Tunnel)	110V Battery - X	2018	Century Yuasa	VRLA
	110V Battery - X	2018	Century Yuasa	VRLA
	110V Battery Charger - X	2018	Century Yuasa	
	110V Battery Charger - Y	2018	Century Yuasa	
YVE (Yarraville)	110V Battery – X Strings 1 & 2	2013	Century Yuasa	VRLA
	110V Battery – Y Strings 1 & 2	2013	Century Yuasa	VRLA
	110V Battery Charger - X	2013	Century Yuasa	
	110V Battery Charger - Y	2013	Century Yuasa	

4.2.2 RISK

4.2.2.1 *Criticality*

> *The most critical component of a protection, control, and monitoring system is the auxiliary DC control power system. Failure of the DC control power can render fault detection devices unable to detect faults, breakers unable to trip for faults, local and remote indication to become inoperable, etc.*[2]

Asset criticality assessment was conducted at the sub-asset class level per the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). Results of this assessment are provided at Appendix A - Asset Criticality Assessment Worksheet. Asset criticality scoring was then used to rank critical assets which have the potential to significantly impact JEN's operational objectives. This helps prioritise implementation of risk mitigation and control measures.

The DC Supply System sub-asset class has an asset criticality score of AC4 (High) due to operational and health and safety consequences associated with failure. This sub-asset class has a high criticality, determined by its:

- High strategic impact on customer supply;
- Damage to assets and risk of injury to people, due to network faults not being isolated given high voltage circuit breakers cannot be automatically tripped without available DC supplies);

[2] Institute of Electrical and Electronics Engineers, Auxiliary DC control power system design for substations, 2007.

- Potential health and environmental impact issues resulting from battery rupture and associated resulting acid spill;
- Regulatory and compliance requirements. The Electricity Safety (Network Assets) Regulations 1999[3] stipulates that all network faults be isolated automatically and without delay - loss of a DC supply system would mean an inability to isolate faults; and
- JEN reputational damage.

4.2.2.2 *Failure modes*

High consequence risk realisation to personnel, damage to assets and network reliability can occur from:

- Failure of DC supply system equipment to supply uninterrupted DC supply to protection and control equipment; and
- Mal-operation of DC supply systems (DC supply quality outside acceptable range), which could damage batteries and protection and control equipment.

Contributing factors to failure of flooded VLA batteries are positive grid corrosion, loss of active material, internal shorts, loss of electrolyte and/or plate sulfation.

Contributing factors to failure of VRLA batteries are internal shorts, thermal runaway, dry out, grid corrosion and plate sulfation.

Contributing factors to failure of battery chargers are leaking capacitors, capacitor dryout, fuses or MCBs of capacitors may also blow or fail (leading to performance degradation such as high AC ripple content in DC output).

4.2.2.3 *Current risks*

The failure risks, types and consequences for DC supply systems are captured in the Risk Register – Secondary Plant in OMNIA and are inherently captured in all other sub-asset classes that the DC system supplies.

4.2.2.4 *Existing controls*

There are three existing controls:

- Condition Based Risk Management (CBRM). Inputs such as inspection and test results, equipment failure trends, SCADA alarms, manufacturer Mean Time Between Failure (MTBF) rating and industry experience are considered when developing CBRM outcomes.
- Online Monitoring. Modern DC supply systems employ comprehensive self-monitoring functions and diagnostic features. These relays are capable of reporting back to JEN's Co-ordination Centre via SCADA when it is faulty; and
- Spares. JEN has a comprehensive spares management system in place for DC system equipment which ensures the availability of healthy and serviceable spares in the event of protection equipment failure.

[3] Electricity Safety (Network Assets) Regulations 1999.

4.2.2.4.1 Control effectiveness

Existing controls are effective. Spares are held for flooded and VRLA type batteries, chargers and DC distribution boards are also held.

Some chargers have continued to operate satisfactorily beyond their lifetime expectation. Planned replacement is informed by performance factors such as ripple content in output (ripple is an undesirable deterioration of charger output).

4.2.2.5 *Future risks*

An emerging risk for this asset class is cybersecurity of IP addressable DC supply systems.

4.2.3 PERFORMANCE

4.2.3.1 *Requirements*

Performance expectations are assessed against the following criteria:

- Operational availability of secondary equipment such as protection, control, metering, SCADA and communication devices;
- Operational availability of primary equipment such as HV circuit breaker closing and opening operations (locally and remotely);
- Zero adverse HSE impact such as operational availability to supply control room emergency lighting, smoke detectors and security systems.

The DC supply system is designed to be in-service continuously to support the standing and momentary DC loads of the zone substation. The nominal design carryover time for JEN zone substation DC supply systems is 8 hours, in accordance with the JEN zone substation Secondary Design Standard (JEN ST 0600).

4.2.3.2 *Life expectancy*

The design life expectancy of flooded VLA batteries and VRLA batteries is typically 15 years and 10 years respectively.

The life expectancy assigned to older chargers manufactured before 1985 is 40 years while for the newer chargers manufactured after 1985, a life expectancy of 20 years has been assigned.

Life expectancy of batteries is influenced by operating temperature with a nominal operating temperature of 25 deg C selected. In accordance with IEEE Standard 450-2002, batteries follow a thermal degradation curve which is based on a widely accepted rule of thumb for lead-acid battery, the Arrhenius equation. Life expectancy of batteries is also adversely affected by AC ripple content in the DC output voltage from chargers and overcharging.

Cold temperatures reduce the available capacity whereas higher temperatures greatly reduce service life of batteries. Typical operating temperatures published by battery manufacturers are:

- **Flooded VLA cells:** (-) 20 deg C to +40 deg C (recommended 10 deg C to 30 deg C)
- **VRLA Cells:** (-) 15 deg C to +45 deg C (recommended 5 deg C to 30 deg C)

Life expectancy of chargers largely depends on the condition of internal electronic and electrical components.

Replacement decisions of batteries and chargers are based upon product lifetime expectations and in-service monitoring.

4.2.3.3 *Age profiles*

Approximate age profile notes show that:

- 82% (28 from 34) of the installed flooded batteries are close to their end of life.
- 30% (14 from 46) of the installed sealed batteries are close to their end of life.
- 26% (21 from 80) of the installed chargers are close to their end of life.

Figure 4–7: Age profile of batteries

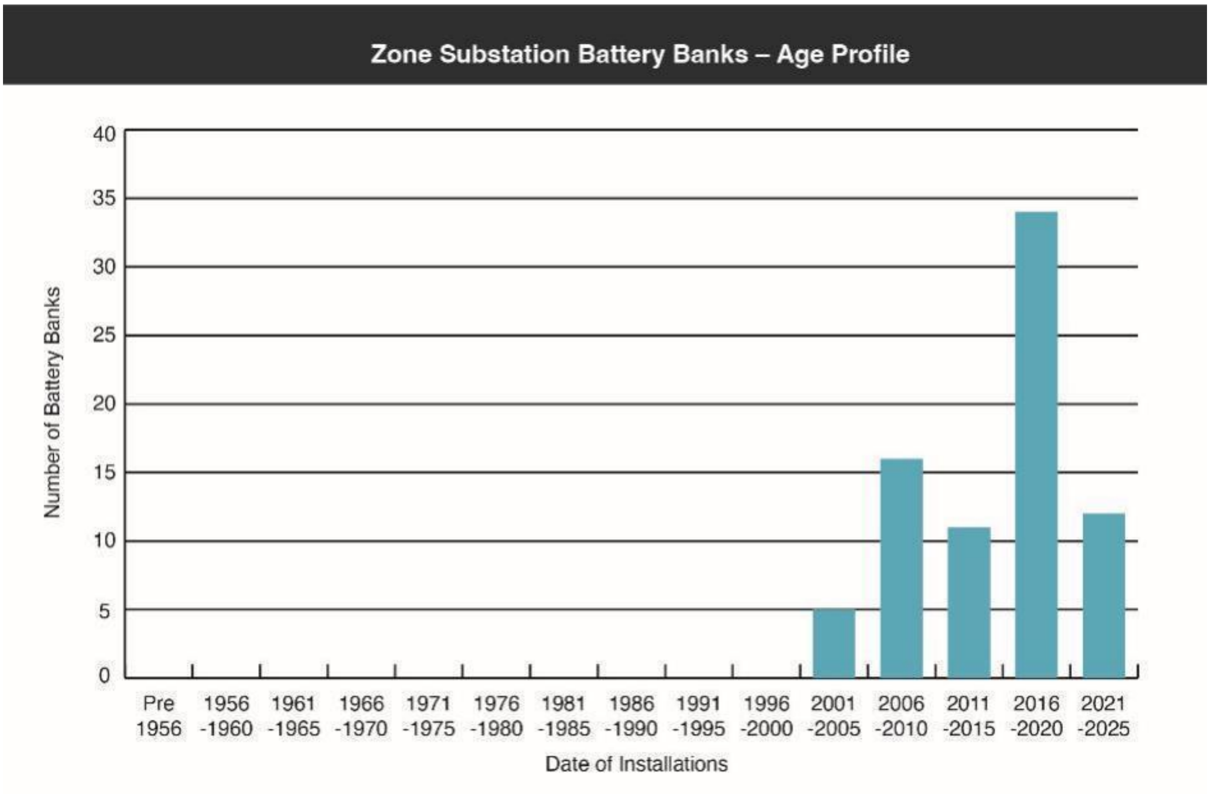


Figure 4–8: Age profile of chargers

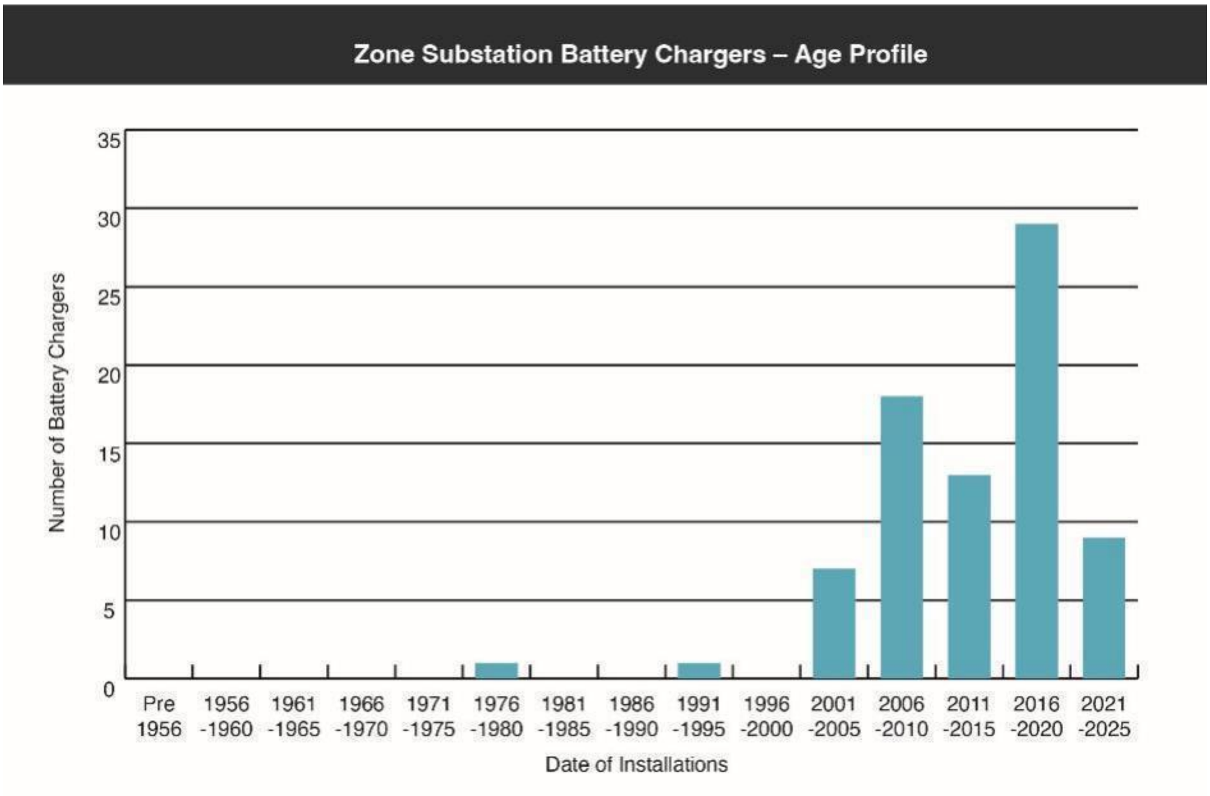


Table 4-9: Battery Chargers Age Profile Information

DC System Equipment	No of Sites Where Installed	No of Battery Banks & Chargers Installed	Life Expectancy	Average Age
Flooded Batteries , VLA	10	33	15	15
Sealed Batteries, VRLA	22	44	10	5
Chargers	32	77	20	12

4.2.3.4 *Performance analysis*

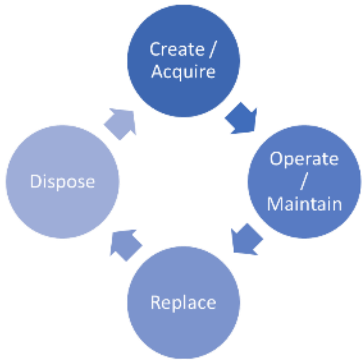
Based on analysis of asset performance information collated from SAP records and routine maintenance records, the current level of performance of this asset class is:

- Annual failure rate of batteries is <1%; and
- Annual failure rate of chargers (including rectifiers) is <2%

There have not been any significant performance issues experienced which is evident by the performance percentages above. Recent failures confirm that asset age is a determinant.

4.2.4 LIFE CYCLE MANAGEMENT

4.2.4.1 *Creation*



Working assets in this sub-asset class are effectively created via acquisition or the deployment of spares. The acquisition triggers for this sub-asset class are:

- New zone substation development works;
- Existing zone substations secondary systems upgrade; and
- Replacement of old assets whose condition has deteriorated and/or which have reached end-of-life

4.2.4.1.1 Spares management

The availability of spare DC supply system equipment is critical. Spare equipment is required in the event of a defect or failure to re-instate full or part functionality of the DC supply system in the shortest possible timeframe.

The objectives of the spares plan are to:

- minimise outage times of the DC supply system; and
- minimise the cost of holding spares.

Like for like replacement of batteries is rather straight forward and is the preferred approach, therefore battery spares are stocked accordingly. There are various types of chargers in service leading to multi-volt chargers being kept as spares. These spare chargers can be used for various DC voltage levels across the network.

Table 4-10: Quantities of DC Supply System Spares

Equipment Type	Quantities	
	Minimum	Maximum
Flooded lead acid batteries – single bank of 240V DC	1	2
Sealed lead acid batteries – single bank of 240V DC	1	2
Chargers	1	2
DC Distribution Boards (from 2021) • 240V DC • 110V DC • 50V DC • 24V DC	 1 1 1 1	 2 2 2 2

Spares are procured either by direct order from supplier or from equipment that has become free from existing in-service population via a planned replacement.

4.2.4.1.1.1 Batteries

- A spare 240V battery bank of flooded lead acid batteries is installed at Coburg North (CN) zone substation; and
- A spare 240V battery bank of VRLA batteries is installed at Pascoe Vale (PV) zone substation.

In addition, there are some flooded type battery banks which have been rendered spare at PV (2-off 50V and 1-off 130V) & COO (1-off 110V and 2-off 50V) zone substations after redevelopment of these substations. These batteries are currently kept charged by corresponding spare chargers at these sites.

4.2.4.1.1.2 Chargers

- 2-off multi-voltage battery chargers are held as spare. These can provide emergency supply for 24V, 50V, 110V or 240V applications. These are usually kept at CN and NT zone substation sites.

4.2.4.1.1.3 DC Distribution Boards

- Spare DC distribution boards of 240V, 110V, 50V and 24V have been sourced and are kept at the Tullamarine depot.

4.2.4.2 *Operation and maintenance*

The sub-asset maintenance program involves:

- Preventive maintenance; and
- Reactive maintenance.

4.2.4.2.1 Preventative Maintenance

The DC supply systems are inspected at 6 monthly and 12 monthly intervals depending on the type of equipment. Flooded batteries require more maintenance than VRLA batteries. Preventive maintenance schedules are created and maintained in SAP. These are based on:

- JEN's work practices;
- Manufacturers recommendations; and
- Australian Standards.

Condition monitoring has been applied to all new installations of DC Supply Systems. This involves measurement and trending of the following parameters:

- Battery voltage monitoring;
- Battery impedance monitoring; and
- Charger health monitoring.

For existing DC Supply System installations, battery internal impedance measurement has been performed since 2016 as a condition monitoring tool for battery health assessment for sealed batteries. In addition, battery capacity tests are planned to assess battery condition and battery remaining Ampere-hour (Ah) capacity.

Routine preventative maintenance of sealed or valve regulated lead acid type batteries is performed on a 6 monthly cycle. The tasks are:

- Visual inspection of the battery bank: checking for any damage to the container, any contamination or signs of leaking;
- Checking of terminals, connections and cabling;
- Measurement of individual battery cell voltages and bank voltage;
- Impedance measurements of each battery cell;
- Confirm readability of all labelling and signage and clean or replace as required; and
- Any additional maintenance task as defined by the battery manufacturer.

Preventive maintenance of flooded or vented lead acid type batteries is also performed on a 6 monthly cycle. In addition to the tasks performed for seals or valve regulated lead acid type batteries, the following tasks are also completed:

- Check water levels and top up with distilled water as required (record water usage);
- Measurement of specific gravity of each battery cell;
- Electrolyte specific gravity measurement for one cell from each battery block; and
- Check operation of battery exhaust fan.

A full description of the recommended operational conditions and maintenance schedules for flooded batteries is provided in Australian standard AS 4029.3, Stationary batteries – Lead Acid Part 3 Pure lead positive pasted plate type.

VRLA batteries require less maintenance because electrolyte levels remain effectively constant under normal operation as the battery is sealed. As a result, there is no requirement to top-up water levels.

A full description of the recommended operational conditions and maintenance schedules for VRLA batteries are provided in Australian standard AS 4029.2, Stationary batteries – Lead-acid Part 2 Valve-regulated type.

Preventative maintenance of battery chargers is performed on a 12-month cycle. The tasks are:

- Visual inspection of the battery charger: checking for signs of damage or deterioration;
- Removal of any foreign objects such as excessive dust etc.;
- Visual inspection of wiring, terminals, test links, panel mounted switches, indicating lights, instrumentation etc.;
- Measure DC output voltage to verify that the voltage output of the charger is within acceptable operational limits;
- Confirm operation of charger alarm(s) and check receipt of charger alarm at the Co-ordination Centre via SCADA; and
- Any additional maintenance tasks as defined by the battery charger manufacturer.

In addition, measurement of the charger DC output ripple is performed every 8 years (aligned with the maintenance regime for protection and control equipment in substations).

4.2.4.2.2 Reactive Maintenance

Reactive maintenance is carried out when faults occur or when defects are identified, resulting in the repair or replacement of assets. Flooded and VRLA type batteries are to be replaced by a similar type. Mixing of VRLA with flooded VLA batteries is not permitted.

DC system equipment faults are typically identified after an investigation arising from an abnormal operation or lack of operation. They may also be identified during routine preventative maintenance or via some form of health condition monitoring with an alarm received in the JEN Control Room via SCADA. Faults must be addressed as a matter of urgency as they represent issues or problems that will or have affected the performance and/or intended operation of critical protection and control equipment.

All equipment faults are fully investigated to identify and understand the root cause or failure mode.

Assumptions underpinning performance of this sub-asset class are:

- Ageing of all batteries across the whole installed base occurs at the same rate; and
- Both hardware and software related failures (e.g. in charger control circuits) have been considered.

Other factors (e.g. battery impedance and voltage measurement, battery capacity measurement etc.) are included, as applicable, in performance measures.

4.2.4.3 *Replacement/disposal*

There are three possible replacement modes available for this sub-asset:

- Run to failure (reactive);
- Schedule-based replacement (age-based); and
- Condition-based replacement (the most cost efficient and effective).

4.2.4.3.1 Run to failure

Run to failure means replacement occurs reactively upon failure (irrespective of age or condition). This mode is unacceptable for high criticality sub-assets like DC supply systems.

4.2.4.3.2 Schedule-based replacement

Schedule-based replacement, in this context, proposes that DC supply system equipment is replaced at the end of its respective design/product life. It can also mean replacement is driven by a large substation refurbishment project.

4.2.4.3.3 Condition-based replacement

Condition-based replacement is determined by CBRM data:

- Age of asset;
- Preventative maintenance records;
- Performance of asset; and
- Network Management System monitoring.

As per Australian Standard AS2676.2 (Guide to the installation, maintenance, testing and replacement of secondary batteries in buildings Sealed cells), ‘Physical characteristics, such as age, are often deciding factors for complete battery or individual cell replacement’. A similar suggestion is made in AS2676.1 for flooded batteries. Thus, age is a critical factor leading to performance degradation of batteries and is the principal criterion for planning replacement of batteries. However, scheduled replacement of equipment based solely on age is not considered best practice asset management because it may result in unnecessary costs.

It is preferable to replace DC supply systems equipment that is not fit for service based on condition or exhibiting symptoms of deterioration. This scenario is considered the most cost effective to meet performance requirements.

The life cycle of older types of chargers can be extended to some extent by preventive maintenance (e.g. regular inspection and replacement of critical components like electrolytic capacitors) in so far it is cost-effective.

Continuous monitoring of asset condition and availability is critical to the asset management strategy based on risk related to condition and age. In existing installations, some chargers are equipped with a charger failure alarm which is integrated into the SCADA system. For other chargers that do not have this functionality, a remote charger fail alarm monitoring feature is progressively being implemented. This will ensure that any charger failures are immediately reported to JEN Control Room via the SCADA network.

Remote access to DC supply systems is also being implemented in newer installations like Yarraville zone substation (YVE). This is being done to remotely collect long-term trending information on the health of batteries (based on voltage and impedance measurements) to further understand the performance and condition of battery systems.

While almost all existing installations have single non-redundant systems, redundancy has been mandated in the JEN Secondary Design Standard for all new installations and major redevelopment projects. A redundant system provides not only flexibility in operation and maintenance of systems but also promotes availability of systems.

Most existing substation battery banks and battery chargers are not duplicated. These consist of single systems which provide DC supplies ranging from 24V to 240V to support protection & control, SCADA and communication equipment and to operate legacy high voltage switchgear.

Typically, each system is constructed from standard 6V battery blocks connected in series to achieve the required voltage (for example 18 x 6V for a nominal 110V system). Additionally, in many older zone substations, more than one DC supply system has been installed, with each system being a standalone system and supplying separate loads, for example 50V systems are used for SCADA or communications equipment while 24V systems are used for VF inter-trip equipment. These legacy DC supply systems are being progressively phased out over time, and to achieve cost efficiencies, the timing is aligned with primary or secondary equipment replacements. In some cases, DC-DC converters are provided to convert 110V DC nominal voltages to 50V or 24V.

The zone substation Secondary Design Standard (JEN ST 0600) stipulates installing fully duplicated X & Y 110V DC Supply Systems for projects involving major redevelopment of secondary systems. These systems consist of 110V DC VRLA batteries and switch mode rectifier (SMR) chargers.

For replacement of existing DC Supply Systems which have reached end-of-life, the general policy is like-for-like replacement, with due consideration for:

- Reducing the overall number of make and model of equipment and standardising on a few makes and models in the installed base;
- Equipment with improved new technology (e.g. SMR chargers).

Occasionally, a battery experiences stresses that can cause the case to swell, crack or lose a cap. Batteries in this condition are considered ‘damaged’ and are subject to more stringent regulations. Damaged batteries pose the risk of releasing hazardous materials.

Current disposal practice is when batteries are retired or replaced, these are packed in accordance with the procedures for packing and transportation as recommended by JEN recycling service provider. The batteries are then transported and disposed by the recycling service provider.

Faulty charger equipment is returned, if appropriate, to the manufacturer for post failure analysis and repaired if economically expedient.

Any faulty equipment that cannot be repaired is disposed of accordingly by a certified recycling company in accordance with JEN’s Environment Policy (JEM PO 0397).

The capital expenditure replacement timeframe may be adjusted depending on the need to undertake associated works at the specific zone substation such as replacement of circuit breaker, transformers and secondary system equipment. Additionally, zone substation augmentation works may influence capital expenditure replacement timeframes for DC systems.

Table 4-11: DC supply systems forecast capital expenditure

Location	Year	Reasons for replacement	Comments
FW	2025	Replace zone substation battery banks and chargers approaching end of life	To be implemented as part of the current FW zone substation redevelopment project.

Location	Year	Reasons for replacement	Comments
ST	2031	Batteries (250V Control, 50V Control and 50V communication) approaching end of life.	Funded together under the battery and charger replacement project. NEI to be coordinated with NH/NEI/TTS 66kV line Pilot Wire protection scheme, 66kV NEI loop augmentation and NELP operational supply projects
TH	2031	Batteries (240V Control, 50V Control and 50V communication) approaching end of life 50V Charger approaching end of life.	
NEI	2031	Batteries (120V Control, 24V Control batteries) approaching end of life Replacement of charger.	
VCO	2031	Batteries (120V Control, 24V Dirty and 24V Clean) approaching end of life.	
YVE	2031	Sealed batteries (Duplicated X & Y 110V DC) approaching end of life.	
BMS	2031	Sealed batteries (Duplicated X & Y 110V DC) approaching end of life.	
TMA	2031	Sealed batteries (Duplicated X & Y 110V DC) approaching end of life.	
EPN	2031	Sealed batteries (Duplicated X & Y 110V DC) approaching end of life.	
CN	2028	Existing batteries (240V Control, 50V Control and 24V communication) and Chargers reaching end of life Replacement of existing DC supply system by new duplicated X & Y DC system, aligning with CN relay replacement project.	Replacement cost is included in the CN redevelopment project.
CS	2030	Chargers reaching end of life Replacement of existing DC supply system by new duplicated X & Y DC system, aligning with CS relay replacement project.	Replacement cost is included in the CS redevelopment project.
NH	2032	Chargers reaching end of life Replacement of existing DC supply system by new duplicated X & Y DC system, aligning with NH redevelopment project.	Replacement cost is included in the NH redevelopment project.

4.2.5 FUTURE IMPROVEMENTS

DC system equipment has proved reliable as reflected by the low failure rates however there are several systems nearing the end of age increasing the risk of failure. Apart from age to assess the risk of failure of DC systems, the following considerations can also be used as a leading indicator:

- Introducing battery capacity testing to determine when they decline below 80% rated capacity;
- Remote monitoring of flooded VLA batteries; and
- Automating trend analysis from hardcopy routine maintenance records kept by field personnel.

4.3 ZONE SUBSTATION SCADA AND COMMUNICATION SYSTEMS

4.3.1 INTRODUCTION

Zone substation SCADA / Communication systems provide real-time and historical information for the effective operation and monitoring of JEN. SCADA systems play a critical role in the management of assets (at the zone substation and in the field) and daily electricity network operations. SCADA systems comprise of the following equipment:

- Remote Terminal Unit (RTU);
- Zone substation (ZSS) Gateway, Station IO and Human Machine Interface (HMI); and
- Global Position System (GPS) Clocks

Devices such as IEDs connect to the RTU and are controlled via a range of protocols including analogue or discrete digital connections and TCP/IP based protocols such as DNP3.0 or IEC61850 depending on the type of the substation. RTUs are critical for the monitoring of JEN secondary systems in the field and zone substations. Performance of the RTU is measured through combined efforts of the JEN SCADA system, JEN Control Room and JEN field support teams.

The ZSS Gateway and HMI can either be stand alone or embedded. Communication between all zone substation secondary equipment and the SCADA host (JEN Network Operations Centre (NOC)) shall be via the ZSS gateway when a ZSS gateway (Digital substation) is implemented. As part of the gateway a station IO is implemented to facilitate control and monitoring of any hardwired connections. The ZSS gateway shall provide a local aggregation point where operators, testers and engineers can:

- visualise and monitor the electricity distribution system;
- view and acknowledge alarms;
- perform GOOSE signals isolation; and
- perform control of the primary and secondary systems.

GPS clocks are deployed to synchronise time stamping of IEDs and field SCADA devices. GPS clocks help maintain reliability of supply to customers as the loss of GPS clock data for synchronisation of IED and other zone substation equipment clocks can impact upon the ability to accurately analyse system events because there would be no time stamping recorded.

4.3.2 RISK

4.3.2.1 *Criticality*

Asset criticality assessments were conducted in line with the JEN's Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). Results of this assessment are presented in Appendix A.

The ZSS Gateway and RTU equipment has been assessed as AC2 - Moderate Criticality because the JEN RTUs facilitate communications between zone substation field SCADA devices, protection & control IEDs and the JEN Control Room.

The GPS clock has been assessed as AC1 – Low Criticality because their failure does not have an immediate effect and there is no possibility to impact customer supply.

4.3.2.2 *Failure Modes*

ZSS Gateway or RTU failures are likely to cause the JEN Control Room to lose visibility and control to these devices depending on the nature of the fault. In the event of faults, loss of connectivity to these devices could result in loss of remote monitoring capabilities and control functionality such as switching.

The failure risks, types and consequences of zone substation Gateway and RTUs are assessed based on historic failures. These issues are generally caused by power supply, processor modules, communications modules and input/output module failure. CPU performance, memory utilisation and other statistics are logged, with worsening trends flagged for intervention.

GPS clock functionality is considered lost if it fails to provide accurate time synchronisation data to field IEDs. This could be caused by several factors such as age-related deterioration of components or power supply failure. These hardware faults require repair or replacement of the unit.

Loss of satellite signal acquisition will also be considered a failure as unit time synchronisation will rapidly become inaccurate because the unit is unable to receive GPS synchronisation signals. GPS signal acquisition loss could be caused by factors external to the unit including failure of antenna or cabling, physical obstruction of antenna line of site to the sky or other interference.

Failure risks for GPS clocks is assessed as low impact and low likelihood given GPS clocks are generally very reliable. Failures are easily managed through rapid repair or replacement as they occur.

4.3.2.3 *Current Risks*

JEN zone substation SCADA system failure risks, types and consequences are captured in Risk Register – Secondary Plant in OMNIA.

4.3.2.4 *Existing Controls*

Existing controls for SCADA system equipment are essentially those maintenance tasks registered on SAP, together with performance and status monitoring.

Contingency plans are immediate response to system alarms by field crews to resolve the issues. If required, the failed equipment will be replaced with spares from stock.

4.3.2.5 *Future Risks*

Emerging risks for this sub-asset class are:

- Cyber Security. Unauthorised access to RTU connected IEDs could cause service disruption and compromise operation of the electricity distribution network; and
- Ageing equipment means the likelihood of failure or mal-operation increases necessitating unplanned replacement. Legacy RTUs such as Schneider C50, C60 and SCD5200 models are no longer supported. Legacy models are replaced with the current model which is backwards compatible.

4.3.3 PERFORMANCE

4.3.3.1 *Requirements*

The performance objective of this sub-asset class is to, in a cost efficient and effective manner, maintain reliability of supply to customers and facilitate the safe and efficient functioning of the JEN power system. Impact upon supply reliability can result from failure of ZSS Gateway or RTU (to communicate with the JEN field SCADA devices, protection relays and head end equipment).

JEN zone substation Gateways and RTUs are expected to operate continuously providing substation functionality and communications up to their rated specifications.

Gateways and RTUs are selected and installed in accordance with JEN's Communications Design & Installation Standard (JEN PR 0029).

GPS clocks must support satellite connectivity and provide 24/7-time synchronisation of protection relays to allow sequence of events analysis, defined up to the millisecond.

4.3.3.2 *Life Expectancy*

RTUs are expected to be 20 years each based on the manufacturer's estimation and industry experience. Several factors determine if an individual RTU has a good probability that it will continue to reliably perform. These are the CBRM factors which include age, condition, utilisation, effectiveness of risk controls and analysis of actual performance.

The life expectancy for the Abbey and Tekron GPS clocks are 7 and 20 years, respectively. The Abbey GPS clocks are an older technology and are being phased out. The newer Tekron GPS clocks are manufactured to align with the product life of an IED, i.e. 20 years.

4.3.3.3 *Age profiles*

There are 34 RTUs.

Figure 4–9: Age profile of the RTUs

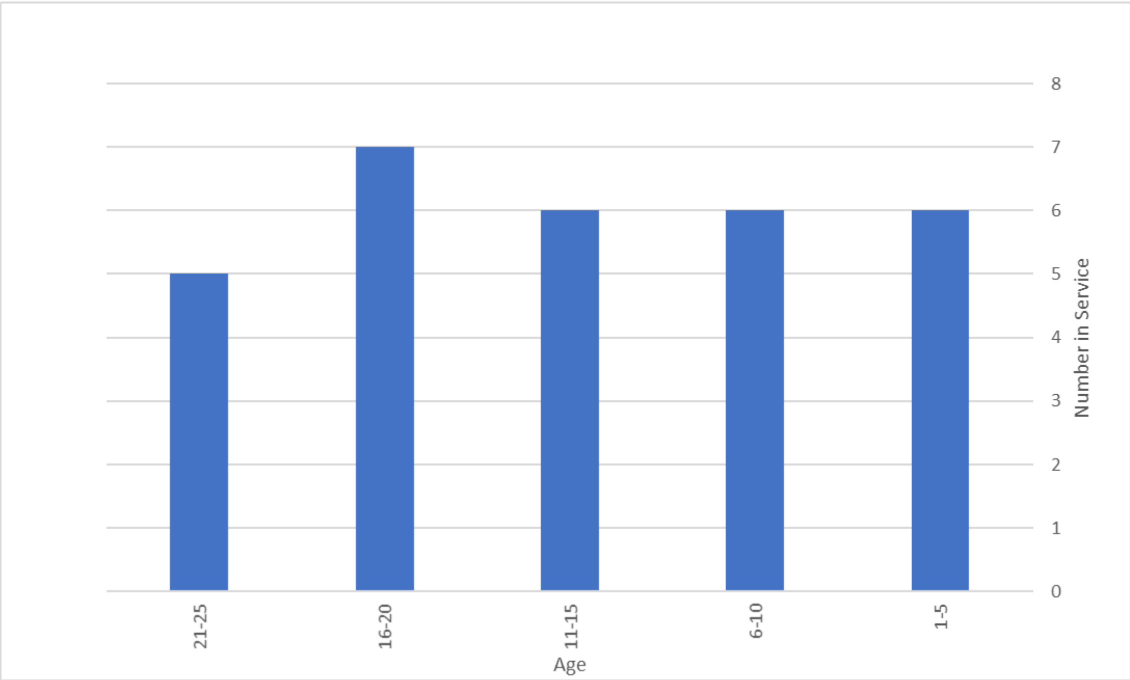


Table 4-12: GPS clocks install base by brand

Model	Quantity	Installed between	
Abbey B06-061	3	2005	2005
TEKRON GPS TCG 01	5	2005	2012
TEKRON GPS TCG 01 E	23	2012	2016
TEKRON GPS TCG 01 G	9	2015	2022
TEKRON GPS NTS03 -G	4	2020	2022

Figure 4–10: Age profiles for GPS clocks

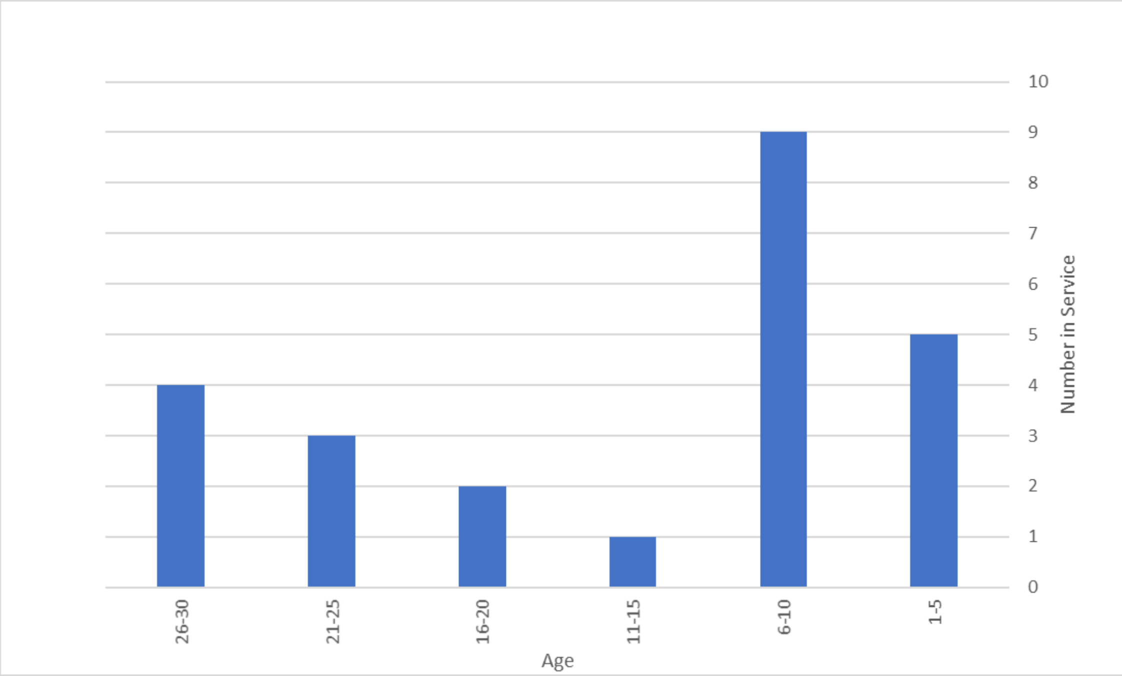


Table 4-13: GPS clocks age profile information

Sub Asset	Qty	Life Expectancy	Average age
RTU	34	20	6.4
Gateway/HMI		20	
GPS Clocks	44	7-20	10

4.3.3.4 *Utilisation*

The ZSS Gateways and RTUs are in-service continuously to enable monitoring and control. A GPS clock is utilised whenever there is a relay event and GPS data is required.

4.3.3.5 *Performance analysis*

There are 2 digital substation sites, where the IEC61850 standard has been implemented, that utilise a station gateway and station IO instead of RTUs. No gateway failures with these installations have occurred to date. Root cause analysis will be performed for each failure or mal operation of a zone substation gateway or RTU.

Zone substation RTU reliability performance continues to be good despite several RTUs approaching the average expected operating life of 20 years of age. RTU software faults are normally fixed by remote system rebooting and are not recorded in SAP.

The performance and reliability of GPS clocks have also been good with few failures attributed to faulty power supplies or resistive joints. No significant issues have been identified for more recent models such as the Tekron TCG-01 E and Tekron TCG-01 G series devices. Obsolescence has been identified with the Abbey B06-061 and TEKRON TCG 01 models.

The Abbey B06-061 is a legacy model in-service at 2 zone substations (East Preston and Footscray West). There is a capital expenditure plan to replace this model at Footscray West. No replacement plan has been made for East Preston because that zone substation shall be decommissioned in 2029.

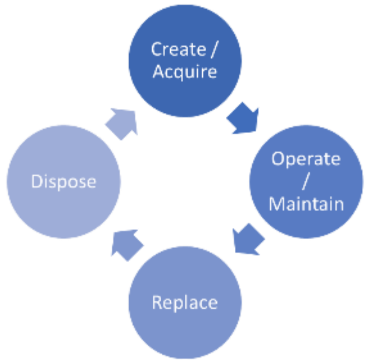
TEKRON TCG 01 GPS clocks installed at Newport and Somerton are experiencing similar issues to the Abbey B06-61 and replacements are also planned.

4.3.3.6 *Controls effectiveness*

The principal risk control is oversight of SCADA operation and events at the JEN Control Room. This is proven to be highly effective with any issues, alarms or events flagged for investigation.

4.3.4 LIFE CYCLE MANAGEMENT

4.3.4.1 *Creation*



Two scenarios trigger the need to acquire and install a new SCADA system equipment:

- To replace an RTU or GPS clock that is beyond economic repair; and
- The building, or refurbishment, of a substation, data centre or communications room facilities.

Table 4-14: RTU, Gateway and GPS Clock spares quantities

Equipment Type		Quantity	
		Minimum	Maximum
RTU	Schneider SCD5200 / SCD6000	2	4
	ABB	1	2
Gateway	Cooper Eaton SG-4260	1	2
GPS Clock	Tekron TCG-01	1	2
	Tekron TCG-03 G	**1**	**2**

Supplier lead times are typically 6-8 weeks.

4.3.4.2 *Operation and maintenance*

This sub-asset maintenance program involves:

- Preventive maintenance; and
- Reactive maintenance.

Preventative maintenance consists of continuous monitoring and scheduled inspection and testing:

- RTU operational status and fault statistics are monitored within the JEN SCADA system. The field SCADA team analyses these performance trends monthly;
- If SCADA hosts begin to receive error status flags from a zone substation RTU or gateway, the equipment would be monitored more closely;
- The operational status of the ZSS SCADA equipment along with the other communications assets are presented in the monthly asset operation report;

- A scheduled maintenance plan of JEN zone substation SCADA system equipment on SAP (two-yearly); and
- maintenance records are also kept in hardcopy.

Reactive maintenance consists of:

- Repair within 24 hours; or
- Replacement (with a spare) within 24 hours.

4.3.4.3 *Replacement/disposal*

Generally, there are three maintenance modes available for this sub-asset life cycle management. The alternative sub-asset replacement modes are:

- Run to failure (reactive);
- Schedule-based replacement (age-based); and
- Condition-based replacement (the most cost efficient and effective).

Run to failure means replacement occurs reactively upon failure (irrespective of age or condition).

Schedule-based replacement, in this context, proposes that each type of equipment within ZSS SCADA sub-asset class is replaced at the end of its respective design/product life. It can also mean replacement driven by a substation refurbishment projects, e.g. protection relay upgrade.

Condition-based replacement is determined by CBRM data:

- Age of asset;
- Preventative maintenance activities and record keeping;
- Performance of asset; and
- Network Management System monitoring.

Decommissioned equipment is disposed of by a certified recycling company in accordance with JEN's Environment Policy (JEM PO 0397).

Table 4-15: RTUs forecast capital expenditure

Location	Year	Reasons for replacement	Comments
CN	2028	A new Gateway SG4260 and IO IED will be installed, aligning with CN redevelopment project (including implementation of IEC61850 standard).	Replacement cost is included in the CN redevelopment project.
CS	2030	A new Gateway SG4260 and IO IED will be installed, aligning with CS redevelopment project (including implementation of IEC61850 standard).	Replacement cost is included in the CS redevelopment project.
BY	2032	The C50 RTU has been in-service for over 20 years and it is out of vendor support A Cooper station gateway SG4260 with the built in HMI functions will be installed to replace the C50 RTU. HMI functionality is required to be retained hence the installation of this nonstandard unit.	Align with Primary plant replacement project (transformers and switchgear) at BY.

Location	Year	Reasons for replacement	Comments
NEI	2026	An SCD6000 RTU will be installed to replace the SCD5200 based on the current JEN standard.	NEI to be coordinated with NH/NEI/TTS 66kV line Pilot Wire protection scheme, 66kV NEI loop augmentation and NELP operational supply projects
NH	2032	The SCD5200 RTU at NH has been in-service for over 20 years and it is out of vendor support. A new Gateway SG4260 and IO IED will be installed, aligning with NH redevelopment project (including implementation of IEC61850 standard).	Replacement cost is included in the NH redevelopment project.

Table 4-16: GPS clocks capital expenditure

Location	Year	Reasons for Replacement	Comments
FW	2025	As part of FW Redevelopment project	To be implemented with the FW Redevelopment Project.
CN	2028	No GPS clock in-service	Replacement cost is included in the CN redevelopment project.
CBN	2028	New zone substation to be established	To be installed as part of the Establish Craigieburn zone substation project.
CS	2030	Abbey B06-061 change out Out of vendor support, not working with the current deployed CS zone substation protection relays	Replacement cost is included in the CS redevelopment project.
BY	2032	No GPS clock in-service	Align with Primary plant replacement project (transformers and switchgear) at BY.

4.3.5 FUTURE IMPROVEMENTS

With the incremental implementation of the Digital Substation Objectives (IEC 61850 standard), various models of Gateways, ZSS IO, HMI and RTUs may come into play. It will be beneficial to standardise on one make and model (in order to achieve training, operation, testing, engineering and inventory efficiencies).

4.4 OPERATIONAL TECHNOLOGY

4.4.1 INTRODUCTION

Communications Systems are designed and configured to facilitate efficient interfacing between JEN assets (primary, secondary, metering and distribution) and the host SCADA system i.e. the JEN Network Operations Centre.

Operational Technology is generally used to describe all communication equipment and schemes which are used for operation of network such as JEN. The performance requirement of OT equipment is driven by reliability and availability.

All equipment used in Communications Systems are expected to operate continuously providing communications capacity within device specifications. Communications Systems infrastructure shall adequately meet communications requirements of protection and control; remote engineering access; and SCADA services with acceptable performance, reliability, safety and environmental impact.

Consequences of communications systems outages could mean:

- Loss of monitoring and system parameter data;
- Loss of visibility of device status;
- Inability to control network elements;
- Longer service restoration due to lack of system monitoring to assist with locating issues; and
- Longer service restoration time owing to manual switching operations.

This sub-asset class strategy aims to achieve efficiencies through:

- Strategic sourcing and effective evaluation of options;
- Optimisation of maintenance costs through an effective maintenance plan; and
- Utilisation of information about the asset (including risk, performance, life cycle management and expenditure estimates).

4.4.1.1 *Sub-Asset Class Functionality and Types*

The Communications System sub-asset class consists of the following equipment:

- Communications Network Devices
- Communications Cabling
- Multiplexer Systems
- iNET radio & cellular.

4.4.1.1.1 Communications Network Devices - Ethernet switches and Routers

Communication Network devices such as Ethernet Switches and Routers are located within each zone substation, at the network head end and in some cases in ACR cabinets. These devices forward and filter OSI layer 2 traffic between ports. Layer 2 traffic management utilised Media Access Control (MAC) addresses in packets. These devices have multiple ports allowing for a star or ring network topology. Additionally, Ethernet switches can be interlinked or cascaded.

Routers are layer 3 devices capable of forwarding traffic between networks by processing routing information included in the packet or datagram. These are located at the head end.

4.4.1.1.2 Communications Cabling - Copper cabling, Fibre-optic

JEN has a mix of copper and fibre optic cabling used for communications. Copper cables were the first type of technology used to establish communication systems within JEN however several installations have exceeded their end-of-life expectancy. These assets will be decommissioned systematically with related protection and control projects.

Fibre optic cables were first installed in JEN in 2001 and have replaced copper cabling as the type of communications systems cabling to be implemented.

4.4.1.1.3 Multiplexer Systems - Nokia multiplexers, Voice Frequency (VF) equipment

JEN's multiplexing is a complicated system using an X & Y ring topology with redundant loops for each line protection scheme. Multiplexing is used to increase the utilisation of communications cable assets given one cable core can be used to carry many circuits. The Nokia Multiplexer platform has been in service throughout JEN for over ten years and has grown to provide a resilient, cost effective and reliable communications solution for critical SCADA and tele-protection services.

VF equipment are legacy systems and are being superseded with multiplexers, hence no further VF installations will take place. Multiplexer installations began in 2001 with replacement plans considered for the upcoming EDPR period due to serval installations nearing or meeting their end-of life expectancy.

Owing to the obsolescence of MUX technology and dwindling support for MUXes, JEN has moved from Multiplexers to MPLS (Multiprotocol Label Switching) technology recently, and MPLS equipment will be installed in all major substation redevelopment projects or new substation projects.

4.4.1.1.4 iNET radio & cellular - GE MDS iNet radio transceivers, Cybertec 3G modems

The radio transceiver and cellular modem services consist of wireless distribution automation systems (GE MDS iNet radio network and Telstra 3G service) used for communications to:

- Automatic Circuit Reclosers (ACR) pole top radio;
- Remote Control Gas Switches (RCGS) pole top radio;
- Fault Indicators (FI) pole top radio;
- Power Quality Meters (PQM) cellular modems at end of feeder kiosk; and
- Ring Main Units (RMU) cellular modems in a kiosk.

Radio communications systems are designed with Access Points (AP) that group remote radio sites. Each remote site serves an ACR, a RCGS or a FI.

4.4.2 RISK

4.4.2.1 *Criticality*

Asset criticality assessments were conducted on a functional basis and followed the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003). Results of this assessment are presented in Appendix A.

Communications network devices have been assessed as AC2 - Moderate Criticality given they are deployed to supply communications services to field and zone substation SCADA devices for engineering access and monitoring and control.

Communications cable has been assessed as AC3 – Significant Criticality due to the cables providing highly critical communications services to JEN zone substations.

The multiplexer systems have been assessed as AC3 - Significant Criticality due to the multiplexers function of providing communication services over fibre optic cable to critical 66kV line protection schemes and major SCADA traffic to and from JEN zone substations. Dual X & Y multiplexer systems are installed at each zone substations for redundancy, representative of its criticality rating.

Radio transceivers and cellular modems have been assessed as AC3 – Significant Criticality given the JEN iNet radio and 3G service are deployed to supply SCADA communications to distribution automation devices such as RCGS, ACR, FI, PQM and RMU. If a communications failure occurs during an electricity network fault, restoration of supply could be delayed due to the loss of visibility to the status of the ACR, RCGS or FI.

4.4.2.2 *Failure Modes*

Failure of communications systems equipment can appear as either:

- A non-operation, that is, it does not operate when required to do so – such as a power supply failure and expected cuts in cabling; or
- An unwanted operation or mal-operation – such as temporary disconnections, data glitches or abnormalities.

4.4.2.3 *Current Risks*

JEN Communications System failure risks, types and consequences are captured in Risk Register – Secondary Plant in OMNIA.

The major risk associated with communications network device failure is loss of visibility and control to other secondary system equipment. During a network fault, this could cause the delay of service restoration. In the great majority of cases, physical issues with JEN primary equipment will result in operation of protection. Issues requiring rapid operator intervention are conceivable such as a high impedance fault that is not cleared by protection, one example could be downed wires on dry asphalt or the failure of protection to clear a fault.

The risk of communications cable and multiplexer failures are ‘Significant’ based on current JEN Risk Assessment standard. The major risk associated with this failure has been linked to redundancy losses of 66 kV line protection schemes. The likelihood and consequence of this type of failure occurrence are Possible and Severe respectively.

The risk of radio transceivers and cellular modems failure is ‘Significant’ based on current JEN Risk Assessment standard. The major risk associated with this sub-asset class failure has been identified as losing visibility and remote control.

4.4.2.4 *Existing Controls*

There are three existing controls:

- Those detailed in the recommended condition monitoring and maintenance tasks together with initiation of replacement projects for assets determined to be at risk of failure;
- Online Monitoring. Modern Communications system equipment has self-monitoring functions and diagnostic features that are capable of reporting back to JEN’s Co-ordination Centre via SCADA when it is faulty. Should a fault occur, an immediate response by field crew is conducted in which the device is repaired or replaced with consideration into the level of redundancy installed; and
- Spares. JEN has a comprehensive spares management system in place for communications system equipment which ensures the availability of healthy and serviceable spares in the event of protection equipment failure.

4.4.2.5 *Future Risks*

Emerging risks for this sub-asset class are:

- Cyber Security. Unauthorised access to JEN assets could cause service disruption and compromise the operation of the electricity distribution network from a lack of functionality, visibility and control;
- Ageing equipment such as copper supervisory cabling and 3G cellular services means the likelihood of failure or mal-operation equipment from end-of-life or retired telecommunication carriers services, in-turn increasing unplanned replacements or upgrades; and
- Network bandwidth utilisation is within capacity of communication links provided by the equipment and network latencies are adequate however with the implementation of Asset Portfolio Objections (Digital substation, Distribution and substation monitoring, REFCL and Operational Communications) bandwidth demand is expected to grow and will be influenced by third parties depending on the evolution of technology.

4.4.3 PERFORMANCE

4.4.3.1 *Requirements*

The critical nature of the JEN communications network necessitates redundancy within practical reason. Communications between zone substations are configured in loops and are fully redundant as per this requirement. Switches, IED and RTU connections within zone substations are not fully redundant. The availability and reliability of communications network devices servicing zone substations equipment is expected to be at the same level as that of head end equipment.

Communication network devices, cabling, multiplexers, iNet radio and cellular devices are expected to operate continuously and up to the capacity required by the connected Protection, Control, DC and SCADA equipment. The aim is to avoid 'single contingency' for >9hrs. However, depending on the nature of the fault, it may take longer for JEN contractors to mobilise. In these instances, the fault must be rectified within 24 hours.

All operational communications equipment is selected and installed in accordance with JEN's Communications Design & Installation Standard (JEN PR 0029).

4.4.3.2 *Life Expectancy*

Communications network devices, Multiplexers, Radio transceivers and cellular modems are expected to be 20 years each based on the manufacturer's estimation and industry experience. Several factors determine if these devices will continue to perform reliably. These are CBRM factors such as age, condition, utilisation, effectiveness of risk controls and analysis of actual performance.

The life expectancy for communications cabling is 50 years, supported by empirical evidence (in the case of copper cabling) and the manufacturer's estimation. Factors that can impact life expectancy of cables are as follows, noting that copper cabling is more susceptible to these impacts:

- Water ingress for underground cables;
- Heat and weather conditions for overhead cables; and
- Age related deterioration.

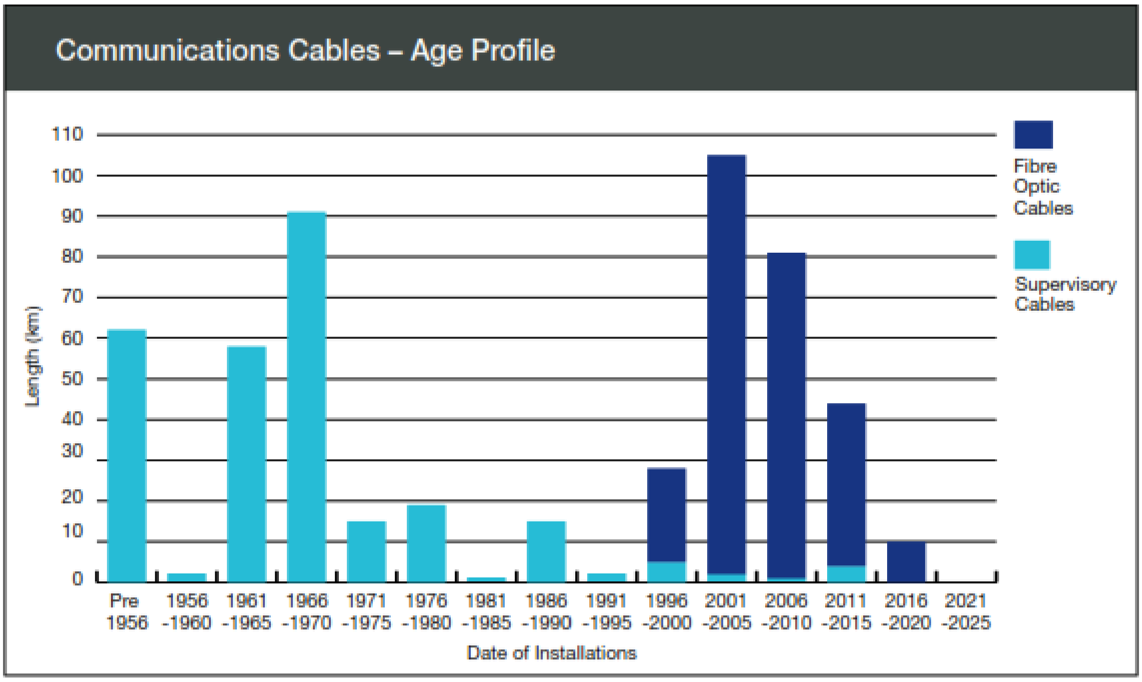
4.4.3.3 *Age profiles*

Table 4-17: Age profile for JEN deployed communications network devices

Model	Quantity	Installed between	
Ruggedcom switch	29	2006	2010
Ruggedcom switch	9	2011	2015
Other comms devices	10	2011	2015
Ruggedcom switch	126	2016	present

The copper supervisory cables have all been in-service in JEN for close or over 50 years. These cables shall be retired when the protection relays and other associated equipment are replaced with more modern equipment using fibre optic cable. The current in-service copper supervisory cables have a total length of about 48 km and were installed between 1943 and 2001.

Figure 4–11: Communications cabling by year installed



The total number of Multiplexers currently in-service is 83.

The total number of iNet radio transceivers currently in-service in JEN is 194 and their installation dates are:

- 8 were installed between 2001 and 2005;
- 80 were installed between 2006 and 2010;
- 105 were installed between 2011 and 2015; and
- 1 was installed between 2016 and 2018.

The total number of 3G modems currently in-service in JEN is 69 and their installation dates are:

- 28 were installed between 2011 and 2015;
- 41 were installed between 2016 and 2018.

4.4.3.4 *Utilisation*

Operational Communications equipment are in-service continuously to enable monitoring and control.

4.4.3.5 *Control effectiveness*

The principal risk control is oversight of SCADA operation and events at the JEN Control Room. This is proven to be highly effective with any issues, alarms or events flagged for investigation.

Furthermore, self-monitoring features of Operational Communications equipment and design redundancy in the applied system have been proven effective.

4.4.3.6 *Performance analysis*

Communications Network devices are classified in terms of reliability, bandwidth, latency and network capacity. Device performance is logged by automated processes and compared with historical performance and similar devices. Devices with worsening trends in performance are closely monitored and considered for replacement. Historical defect data captured on SAP shows approximately one fault occurred per year since 2012. Root cause analysis is performed for each failure however no adverse trends have been identified.

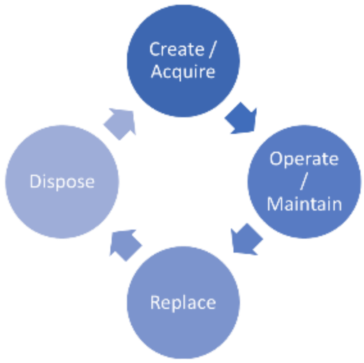
Communication cable failures are usually caused by cables being cut. Typically, underground cables are cut due to excavation and building over cables work. For overhead cables, cutting is generally the result of vehicle collision or sabotage. If the root cause of a cable failure or mal operation is unknown, an investigation would be carried out to determine the root cause with findings allocated to network impact figures (e.g. SAIDI SAIFI and MAIFI). Based on the fault register and supplied by operation staff, the average communication cable failure encountered was 2 events every year for the last 6 years.

When a multiplexer fails or mal-operates, an investigation is carried out to determine the root cause with findings allocated to network impact figures (e.g. SAIDI SAIFI and MAIFI). Based on the fault register in SAP and supplied by operation staff, the average multiplexer failures encountered was 2 events every year for the last 6 years.

No significant adverse condition issues have been identified for iNet radio and 3G services in JEN. Replacement technologies for iNet radio are under investigation with 4G service to be deployed to replace 3G moving forward. When iNet radio or cellular equipment fails or mal-operates, an investigation is carried out to determine the root cause with findings allocated to network impact figures (e.g. SAIDI SAIFI and MAIFI). Based on the fault register in SAP and supplied by operation staff, the average iNet radio and 3G failures encountered was 6 and 1 respectively per year for the last 7 years.

4.4.4 LIFE CYCLE MANAGEMENT

4.4.4.1 *Creation*



Establishment of new Operational Communications equipment is completed in accordance with JEN Communications Design & Installation Standard (JEN PR 0029). More specifically, new radio transceivers and cellular modems are design and installed in accordance with A Guideline for JEN field workers and contractors working in the vicinity of radio frequency fields (JEN GU 0103).

Three scenarios trigger the need to acquire and install new Operational Communications equipment:

- To replace a communications network device that is beyond economic repair;
- A new communications node; and
- The building or refurbishment, of a substation.

Supplier lead times are typically 6-8 weeks, Like for like replacement is preferred, however JEN holds the following spares shown in Table 4-18.

Table 4-18: Spares quantities of communications network devices

Equipment	Quantities	
	Minimum	Maximum
Ruggedcom switch	2	3
Ruggedcom router	1	1
Engineering HMI	0	0
iNet radio transceivers	3	6 (3% of total in-service population)
Cybertec 4G modems	2	4 (5% of total in-service population)
Fibre Optic Cable • Single mode (48 core) • Overhead	2 kms	
Fibre Optic Cable • Single mode (48 core) • Underground	2 kms	
Fibre Optic Cable • Multi-mode	300 m	
Patch Leads • Single mode (2 core) • Various lengths	100	
Patch Leads • Multi-mode (2 core) • Various lengths	100	
AVARA Multiplexers	2	
MPLS Units	2	

4.4.4.2 *Operation and maintenance*

This sub-asset maintenance program involves:

- Preventive maintenance; and
- Reactive maintenance.

Preventative maintenance consists of monitoring, inspection and testing:

- Communications network devices, radio transceivers and cellular modem services operational status and fault statistics are continuously monitored by the Communications Infrastructure Team and presented in a monthly asset operation report;
- Cable attachments to poles and accessories are visually inspected annually;
- SAP is updated to reflect all observations and issues observed during the inspections, using asset inspection procedures and documentation;
- The results of the inspection and observations are reported to the Asset Manager in the monthly Asset Maintenance Performance report; and
- Any potential issues requiring remediation works are initiated and managed through the Service Order process in SAP.

It is the responsibility of the Services and Projects Field SCADA & Communications team to ensure that the maintenance records in SAP are accurate at all times.

Reactive maintenance consists of:

- Repair within 24 hours; or
- Replacement (with a spare) within 24 hours.

4.4.4.3 *Replacement/disposal*

Generally, there are three maintenance modes available for this sub-asset life cycle management. The alternative sub-asset replacement modes are:

- Run to failure (reactive);
- Schedule-based replacement (age-based); and
- Condition-based replacement (the most cost effective).

Run to failure means replacement occurs reactively upon failure (irrespective of age or condition).

Schedule-based replacement, in this context, proposes that each type of equipment within Operations Communications sub-asset class is replaced at the end of its respective design/product life. It can also mean replacement is driven by a substation refurbishment projects, e.g. protection relay upgrade.

Condition-based replacement is determined by CBRM data:

- Age of asset;
- Preventative maintenance activities and record keeping;
- Performance of asset; and
- Network Management System monitoring.

Copper supervisory cables in JEN will eventually be replaced with fibre optic cables. Overhead copper supervisory cable will be removed from poles post-retirement from service. The removed cable shall be disposed in a safe manner so that they do not represent any risk to the distribution network, staff and the public. It shall be the responsibility of JEN Services and Projects teams to ensure appropriate procedures are followed for the disposal of the removed copper supervisory cable.

JEN underground constructed copper supervisory cable shall be abandoned safely and ensured that they are terminated, air-gapped and earthed at the interface between the ground and above ground atmosphere.

Decommissioned equipment is disposed of by a certified recycling company in accordance with JEN's Environment Policy (JEM PO 0397).

Table 4-19: Forecast capital expenditure – Network Devices

Location	Year	Reasons for Replacement	Comments
NH/NEI/TTS	2026	One (1) Ruggedcom switch was installed at TTS in 2006 and it needs to be replaced in 2024; Two (2) new Ruggedcom switches need to be installed at NH to meet the communications requirement based on the current JEN standard. Replacement of supervisory cable from NH to NEI to TTS to be removed and replaced with digital differential protection	To be implemented with NH/NEI/TTS 66kV line Pilot Wire protection scheme replacement project.
CBN	2028	New Ruggedcom Ethernet switches, routers and other communications equipment required as this is a new JEN zone substation development.	To be installed as part of the Establish Craigieburn zone substation project.
CN	2028	New Ruggedcom Ethernet switches, routers and other communications equipment need to be installed to meet the communications requirement of the IEC 61850 zone substation.	To be implemented with the CN Redevelopment Project.
CS	2030	New Ruggedcom Ethernet switches, routers and other communications equipment need to be installed to meet the communications requirement of the IEC 61850 zone substation.	To be implemented with the CS Redevelopment Project.
JEN	2028	Expansion and strengthening of communications network to meet demand	Further strengthen the comms network to enable the addition of more network devices
Various (19 ACRs, 23 Gas switches and 4 ZSS)	2031	Program proposed to mitigate cyber security risks with existing PSCN switches and routers with inadequate security measures nominated for replacement	
NH	2032	New Ruggedcom Ethernet switches, routers and other communications equipment need to be installed to meet the communications requirement of the IEC 61850 zone substation.	To be implemented with the NH Redevelopment Project and coordinated with NH/NEI/TTS 66kV line Pilot Wire protection scheme replacement project.

Table 4-20: Forecast capital expenditure – Cabling

Location	Year	Reasons for Replacement	Comments
Various	2029-2031	Fibre optic cabling approaching end of life Removal of redundant copper supervisory cabling	Staged replacement of fibre optic cable and removal of redundant copper supervisory cabling To be coordinated with applicable zone substation works

Table 4-21: Forecast capital expenditure – MUX and MPLS

Location	Reasons for Replacement	Comments
FW	Two (2) new MPLS systems are required to meet the communications channels requirement for the IEC61850 implementation at FW and BLTS.	To be implemented as part of the FW Redevelopment project.
CN	Two (2) new MPLS systems are required to meet the communications channels requirement for the IEC61850 implementation at CN.	To be implemented with the CN Redevelopment Project.
CS	Two (2) new multiplexer systems are required to meet the communications channels requirement for the IEC61850 implementation at CS.	To be implemented with the CS Redevelopment Project.
NH / NEI	MPLS equipment to be installed to facilitate new 66kV line protection scheme	To be implemented with NH/NEI/TTS 66kV line Pilot Wire protection scheme replacement project.
WMTS, BTS, BD, SBY, SHM, BY, ES, NS, PV, BMS, FT, NT, YVE, FE, PTN, EPN,	Current MUX technology installed to facilitate data exchange in our Operational Technology network is nearing obsolescence with secondary protection and control devices moving towards MPLS technology. Limited support and parts available in market of mux equipment	Staged replacement program to be coordinated with applicable secondary works at affected zone substation or terminal station.

FF, HB, KTS		

Table 4-22: Forecast capital expenditure – iNET radio and cellular

Location	Year	Reasons for Replacement	Comments
Sunbury, Craigieburn, Roxburgh Park, Somerton and Ivanhoe	2026-2031	Existing communications network constraints are leading to adverse safety, performance and asset failure risks. Upgrades and replacements are required to the Operational Technology Communications Network to relieve capacity constraints and facilitate accurate and reliable data exchange between field and zone substation devices.	Staged program to be coordinated with applicable distribution works and secondary works at affected zone substation or terminal station.

4.4.5 FUTURE IMPROVEMENTS

With the incremental implementation of the Digital Substation (IEC 61850 standard), Distribution and Substation Monitoring, various equipment types typically used may no longer be able to facilitate the greater functionality required by Secondary systems. As we continue to capture necessary information in SAP for efficient performance analysis, it will be beneficial to also standardise one make and model for types of Operational Communications equipment so that training, operation, testing, engineering and inventory efficiencies can be realised. The standardisation of equipment type ensures we improve on our current Operations Communications infrastructure and also ensures we integrate new equipment and technologies based on industry market trends and achieve our Asset Portfolio Objectives described in Section 3.1.

4.5 INFORMATION REQUIREMENTS

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

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives (Table 4-23). Table 4-24 identifies the current and future information requirements to support the Sub-Asset Class critical decisions and their value to the Asset Class.

Table 4-25 provides the information initiatives required to provide the future information requirements.

Table 4-23: Information requirements – Business Objectives

Business Objective	JEN Information Sources	Externally Sourced Data
To minimise the damage to network assets and risk to personnel due to network faults	SAP ERP (enterprise resource planning) DrawBridge (drawing management) RESIS (where applicable) Protest Database (where applicable) SCADA ECMS	Manufacturer technical manual Industry fault history Alerts from manufacturer SAI Global – AS/IEC standards

Table 4-24: Information requirements – Critical Business Decision

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Asset creation	• Specification and tender responses • Asset registers in SAP • Asset information in RESIS (as applicable) • Zone substation Secondary Design Standard • JEN IEC61850 Network Design Guide • JEN Communications Design & Installation Standard • New asset project progress reporting. Completion recorded in SAP		• High **–** Regulatory obligation to maintain network continuity and security of supply and safety
When to maintain and replace equipment	Asset register in SAP with details of each asset: • Functional Location • Manufacturer Model • Equipment Description • Installation Date • Technology type • Location/Address • Basic asset specification (as applicable) - Unit transmission loss	• Require published figures of failures (worldwide) • Predictive analytics of asset condition based on a consolidated view of data • Performance indicator for the device (% of availability) as applicable	• High – Regulatory obligation to maintain network continuity and security of supply and safety

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	- Bending radius - Interface type - System capability - Applicable standard • Cable path (as applicable) • Overhead or Underground installation (as applicable) • Asset Defect Register: - Event description - Model - Date and time - Notification Number - Recorded details of work order activities performed and components replaced • Maintenance records - Test results/reports - Tester comments - Condition monitoring & observations - Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP - Manufacturers maintenance manuals • DrawBridge: - Applicable Conceptual and Detailed drawings • Performance History: - Daily Situation Report (DSR) - Incident Investigation Reports (ECMS)	• Photographs of device attached to SAP equipment (as applicable) • Unit cost of replacement • Migrate condition & performance reports/data into SAP to improve analysis and decision making. • Improved recording of inspection and audit reports in SAP including updating missing data and spares holding.	
Respond to defects to restore equipment operationally. Perform corrective maintenance	• Alert via NOC or Daily Situation Report • Asset Defect Register	• All defect data to be collected and stored within SAP to enable effective root cause and performance analysis	• High: Regulatory obligation to maintain network continuity and security of supply and safety
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

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 4-25: Information requirements - Information Initiatives to Support Business Operations

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Require published figures of device failures (worldwide)	To improve analysis and decision making.	Unable to effectively manage the life cycle of the asset	Reliable and accurate device failure data
Predictive analytics of asset condition based on a consolidated view of data	To improve analysis and decision making.	Unable to effectively manage the life cycle of the asset	Reliable and accurate device failure data
Performance indicator for the device (% of availability) as applicable	To measure the performance of the asset against a standard business target (e.g. KPI)	Unable to effectively manage the life cycle of the asset	Performance target endorsed by business
Photographs of device attached to SAP equipment	Avoid unnecessary site visit to validate asset data	Unable to effectively manage the life cycle of the asset	Clear records of device attached to SAP equipment
Unit cost of equipment replacement.	To better budget CAPEX forecast for future replacement.	Inaccurate CAPEX forecast leading to insufficient/over budget.	Accurate unit cost of System equipment replacement by scheme.
Migrate Condition & Performance reports/data into SAP.	To improve analysis and decision making.	Poor efficiency in accessing asset data and possible risk of maintenance inefficiencies.	Asset Data as per SAP requirements.
Improved recording of inspection and audit reports in SAP including updating missing data and spares holding.	To improve analysis and decision making. Avoid unnecessary site visit to validate asset data	Poor efficiency in accessing asset data and possible risk of maintenance inefficiencies.	Asset Data as per SAP requirements.

5 CONSOLIDATED PLAN

5.1 ASSET INVESTMENT PLAN

The Asset Investment Plan (AIP) provides a snapshot of how JEN will be managed to achieve its 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 expenditure 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 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.

5.2 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 ACS.

The COWP aids the 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

6.1 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 North	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

7.1 APPENDIX A – ASSET CRITICALITY ASSESSMENT

ASSET AND BACKGROUND INFORMATION		
Site Name		**General**
Asset Class		**Secondary Plant**
Sub-Asset Class		**All**
Date of Previous Assessment		**21-Aug-18**
Date of Last Review		**16-Aug-23**
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	Comments
1	Protection and Control Equipment - Electro-mechanical, Analogue electronic and Digital/Numerical relays	Risks associated with running protection control relays to failure, resulting in loss of supply / affecting supply reliability	Operational	**Major** due to potential for loss of electricity supply to >2% customers (6,500) > 24 hours	Condition monitoring and maintenance tasks, Online monitoring, Spares	AC4	High	Protection and control systems are highly critical to the safe and reliable operation of the network. Failure to isolate faults will invariably result in severe damage to high voltage apparatus and present a serious health and safety hazard to both operational personnel and the public.
2	DC Supply System - Batteries and Battery Chargers	The risk associated with the loss of duplicated DC supply leading to loss of protection and control schemes.	Operational	**Major** due to potential for: • Total permanent disability (staff or contractors) • Multiple hospitalisations, permanent disability and/or life-threatening injuries affecting member(s) of the public	Condition Based Risk Management (CBRM), Online monitoring, Spares	AC4	High	The major risks associated with failure of a substation DC supply system are: • Damage to assets and risk of injury to people, due to network faults not being isolated (as a result of inability to automatically trip high voltage circuit breakers); and • Potential health and environmental impact issues resulting from battery rupture and associated resulting acid spill
3	Zone substation SCADA Systems - ZSS Gateway and RTU equipment	Failure of a ZSS Gateway and Remote Terminal Unit during a network fault (power supply, processor module, communications module and input or output module) This compromises the fault investigation because it prevents JEN from finding the root cause(s), resulting in recurrences of a similar fault	Operational	**Serious** due to loss of electricity supply to >1% of customers (3,200) up to 3 hrs delayed restoration (worst case a fault occurs on bus) During normal conditions - Risk is considered Minor due to station still in operation even with loss of visibility until attendance to site to rectify	Maintenance tasks, Performance and status monitoring, Contingency/Response plans, Spares	AC2	Moderate	JEN ZSS Gateway and RTU supplies communications between JEN ZSS field SCADA devices, protection & control IEDs and JEN SCADA hosts & JEN COC. Any ZSS Gateway or RTU failure will cause JEN COC to lose visibility and control to these devices. In the event of faults, losing control and visibility to these devices could result in lack of remote monitoring capabilities hence any network control functionality such as switching cannot be performed remotely. This can present extended outages to a large number of customers and requires the deployment of field resources to perform network switching

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	Comments
4	Zone substation SCADA Systems - GPS Clocks	Failure of the GPS clock time stamp due to age, power supply, loss of satellite synchronisation during a fault. If time stamping is incorrect during a fault, the whole purpose of the GPS clocks functionality is lost. This compromises the fault investigation because it prevents JEN from finding the root cause(s), resulting in recurrences of a similar fault	Operational	**Minor** due to potential loss of electricity supply to < 1,000 customers up to 6 hours	Maintenance tasks, Performance and status monitoring, Contingency/Response plans, Spares	AC1	Low	Any GPS clocks failure will cause the secondary system devices lose synchronisation to accurate clock source. In the event of faults, losing synchronisation to accurate clock source means no accurate time sequence of event to be tracked on the secondary system devices to investigate the root cause of the faults. Without removing the root cause(s) of the faults immediately, the faults could reoccur.
5	Operational Communications System - Network Devices	Failure of network device due to power supply and processor failure under fault and normal conditions.	Operational	**Serious** due to potential loss of electricity supply to >1% of customers (3,000) >3 hours delayed restoration During normal conditions - Risk is considered Minor because a zone substation will still be in operation without communications to the control room.	Condition monitoring and maintenance tasks, Online monitoring, Spares	AC2	Moderate	Any communications network device failures will cause JEN control room losing visibility and control to the devices which are directly connected to the failed network device. In the event of faults, losing control and visibility to these devices could result in lack of remote monitoring capabilities hence any network control functionality such as switching cannot be performed remotely. This can present extended outages to a large number of electricity consumers and require the deployment of field resources to perform network switching.
6	Operational Communications System - Cable	Failure of copper supervisory cable or fibre optic cable	Operational	**Severe** due to loss of electricity supply to >1% of customers (3,200) up to 3 hours delayed restoration (worst case a fault occurs on bus)	Condition monitoring and maintenance tasks, Online monitoring, Spares	AC3	Significant	Copper supervisory cable and fibre optic cable provide highly critical communications services to JEN zone substations. All communications circuits for JEN 66kV line protection schemes are established over these cables. Because of their vital requirements within the network, JEN communications cable network has been designed and implemented with redundancy. All communications cables should access a JEN zone substation with dual cable routes via diverse cable paths to prevent single point of failure occurs to JEN communications cable network. If in any case, a fibre cable is subjected to an outage (usually fault caused by truck or high vehicle collision), the down time for crew to re-establish the link and get it up and running is a maximum of 24 hours.

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	Comments
7	Operational Communications System - Multiplexer	Failure of multiplexers supporting line protection schemes	Regulatory & Compliance / Brand, Reputation & Stakeholders	**Severe** due to: • Regulator requires formal explanations & remedial action plans • Fines or penalties from legal issues, breaches or non-compliances due to loss of redundancy of subtransmission line for more than 8 hours (it is a regulatory requirement for this condition not to exceed 8 hours) which could lead to power loss to multiple zone substations • Significant adverse public attention and/or heightened concern from stakeholders	Condition monitoring and maintenance tasks, Online monitoring, Spares	AC3	Significant	JEN Multiplexers and associated cards provide fibre optic cable services to critical line protection links and major SCADA traffic between two zone substations. Because of their vital requirements within the network, there are always two multiplexers per zone substation for the secondary path that is established to service the Y protection, in case of any failure along the primary line section servicing the X protection. For this reason, having 100% functionality on a constantly running asset is crucial. Multiplexers are employed in JEN mainly providing communications services for 66 kV line protection schemes. The multiplexing system has been designed and constructed with redundancy. Should both multiplexers supplying communications links to the protection schemes for the same 66 kV line fail, the 66 kV line should be shut down.
8	Operational Communications System - iNET Radio & 3G Service	Failure of the iNet radio transceivers or 3G modems due to power supply failure during a fault or normal conditions	Operational	**Severe** due to loss of electricity supply to >1% of customers (3,200) up to 3 hours delayed restoration (worst case a fault occurs on bus) During normal conditions - Risk is considered Minor due to loss of electricity supply to <1,000 customers up to 6 hours delayed restoration (worst case a fault occurs on bus) Likelihood: Rare due to redundant links in the network allowing alternate path for services.	Condition monitoring and maintenance tasks, Online monitoring, Spares	AC3	Significant	JEN iNet radio and 3G service are deployed to supply SCADA communications to distribution automation devices such as RCGS, ACR, FI, PQM and RMU. Any link failure will cause JEN control room lose visibility and control to these devices. In the event of faults, losing control and visibility to these devices could result in lack of remote monitoring capabilities hence any network control functionality such as switching cannot be performed remotely. This can present extended outages to a large number of customers and requires the deployment of field resources to perform network switching.

Score	Criticality Rating	Consequence Rating	Description	Consequence Category						
				Financial		Operational	Health, Safety & Environment	Employee	Regulatory & Compliance	Brand / Reputation / Stakeholders
				EBITDA / Cashflow	Recoverable Value					
AC5	**Extreme**	**Catastrophic**	Potential disastrous impact on SGSPAA strategies or operational activities. Widespread stakeholder concern / interest.	[redacted] [redacted]	[redacted] [redacted]	Loss of electricity supply to 2 Zone Substations >24 Hrs or >15% Customers (49,000) >24 Hrs. Loss of gas supply to > 20% Customers (220,000). Business interruption for > 30 days (network / pipelines).	1 or more fatalities (staff, contractors or member(s) of the public). Significant destruction of key internal asset or third-party property. Harm to the natural environment and/ or cultural heritage that cannot be remediated .	Skill set/ capability of >35% of business critical roles lost within a 6 month period	Major regulatory restrictions and/or govt. interventions. Possible loss of licence to operate. Frequent regulatory or policy violations / breaches Major litigation, with a possibility of punitive damages. Significant fines, prosecutions and jail terms possible.	Sustained and hostile public campaign. Reputation impacted with majority of key stakeholders. Sustained and critical stakeholder criticism.
AC4	**High**	**Major**	Significant impact on SGSPAA strategies or operational activities. significant stakeholder concern / interest.	[redacted] [redacted]	[redacted] [redacted]	Loss of electricity supply to > 2 % Customers (6,500) >24 Hrs. Loss of gas supply to > 1% Customers (11,000). Business interruption for 7 – 30 days (network / pipelines / offices).	Total permanent disability (staff or contractors). Multiple hospitalisations, permanent disability and/or life threatening injuries affecting member(s) of the public. Significant damage to internal assets or third-party property. Harm to the natural environment and/ or cultural heritage with remediation difficult (multi-year management).	Skill set/capability of 20 – 35% of business critical roles lost within a 6 month period	Regulatory investigations or govt. review. Some regulatory or policy violations / breaches. Litigation involving significant senior management time. Major fines or penalties and prosecutions possible.	Significant adverse public attention and/or heightened concern from stakeholders. Reputation impacted with significant number of stakeholders. Significant stakeholder criticism/negativity.
AC3	**Significant**	**Severe**	Moderate impact on SGSPAA strategies or operational activities. Moderate stakeholder concern / interest.	[redacted] [redacted]	[redacted] [redacted]	Loss of electricity supply > 1% Customers (3,200) > 24 Hrs. Loss of gas supply to > 0.1% Customers (1,100). Business interruption for 1 - 7 days (network / pipelines / offices).	Single permanent partial disability (staff or contractors). Medical aid required for member(s) of the public. Some loss of or damage to third party property. Harm to the natural environment and/ or cultural heritage that can be remediated (<1 year management).	Skill set/capability of 10-20% of business critical roles lost within a 6-month period	Regulator requires formal explanations & remedial action plans. Fines or penalties from legal issues, breaches / non-compliances.	Persistent public scrutiny. Reputation impacted with some stakeholders. Some stakeholder concern/negativity.
AC2	**Moderate**	**Serious**	No material impact on SGSPAA, issues are dealt with internally.	[redacted] [redacted]	[redacted] [redacted]	Loss of electricity supply to > 1% customers (3,200) > 6 Hrs. Loss of gas supply to > 100 Customers or any contract customer. Business interruption for 1 day (network / pipelines / offices).	Medical treatment injury or lost time injury (staff or contractors). On-site first aid to a small number of member(s) of the public, lost time. Harm to the natural environment and/ or cultural heritage requiring minimal Remediation (at the time of impact).	Skill set/ capability of 5 – 10% of business critical roles lost within a 6-month period	Isolated regulatory or policy violations / breaches. Fines or penalties possible.	Sporadic, adverse media/public attention. Limited adverse reputational impact. Minor stakeholder complaints.
AC1	**Low**	**Minor**	Negligible impact on SGSPAA, issues are routinely dealt with by operational areas.	[redacted] [redacted].	[redacted] [redacted]	Loss of electricity supply to <1,000 Customers up to 6 Hrs. Loss of gas supply to > 5 residential customers. Business interruption for a few hours (offices only).	Minimal impact on health & safety (staff, contractors or member(s) of the public). Harm to the natural environment and/ or cultural heritage requiring no active remediation and/or able to self-remediate.	Skill set/ capability of <5% of business critical roles lost within a 6-month period	General regulatory queries. No violations / breaches, fines or penalties.	Negligible media/public attention, reputational impact and/or little or no stakeholder interest.