Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review - Revised Regulatory Proposal

Supporting justification document

Switchgear Replacement - Business Case

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1. Executive Summary

Key highlights

- This program is required to mitigate risk of overhead switchgear failure on the Jemena Electricity Network (JEN).
- Overhead switchgear on the JEN has a number of issues contributing to observed failure rates. For example:
  - Gas switches are deteriorating due to fault or operation damage to cabling and fittings, switch arm mountings and connections.
  - Low voltage (LV) and high voltage (HV) isolators on a single structure are also deteriorating due to fault or operation damage.
  - Automatic Circuit Reclosers (ACR) are deteriorating due to wear and tear of mechanical components and degradation of control systems.
- Our approach has identified a prudent, cost-effective program of replacements to ensure that we maintain network performance and address JEN compliance requirements.
- The replacement program recommends completion by 30 June 2031, with an estimated total capital expenditure of $10.81M ($2024).

1.1 Purpose

- This document provides the business case to implement overhead line switchgear replacement activities during the 2026-31 regulatory control period. The proposed program, with a total capital expenditure of $10.81M, is part of our forecast replacement capital expenditure.

1.2 Identified need

JEN's HV and LV overhead switchgear is used to facilitate maintenance and construction activity and to reconfigure the network and manage network load. Automated or remote controlled HV gas switches also facilitate the remote control of the network and are critical to JEN's future plans for self-healing network capabilities.

The JEN features a mix of types of overhead switchgear. Installed on the network, there are approximately:

- 431 HV air break switches,
- 2,038 HV disconnectors, and
- 1,317 gas switches.

There is also 232 high voltage HV feeders on the network and each feeder supplies an average of 1,613 customers. Each feeder has an average of 2 air break switches, 9 sets of isolators and 6 gas switches; therefore, a failure to operate can adversely affect the operational efficiency and flexibility of the network.

There are an estimated 13,000 LV three phase switching devices on the LV overhead network.

For reference, the gas insulated switches come in two forms, manual and remote controlled. The remote-controlled units together with remote controlled Automatic Circuit Breakers (ACR's) are the principal devices used to facilitate the remote control and automation of the distribution network.

The key issues associated with JEN's overhead switchgear assets are failure to operate, failure to carry load, overheating, insultation breakdown, hardware mechanical failure, failure to external factors and failure due to operational errors or by third parties.

Several overhead switchgear replacement projects have been identified to ensure that we address asset risks upon failure, to ultimately maintain network performance and address JEN's compliance requirements. The proposed expenditure is critical to restoring parts of the network impacted by overhead switchgear faults to a secure operating state.

The known issues with overhead switchgear are described below:

Issue	Description of Issues
1	**Asset risk** - The key issues associated with overhead line switchgear are failure to operate, failure to carry load, overheating, insultation breakdown, hardware mechanical failure, failure due to external factors and failure due to operational errors or by third parties.
2	**Regulatory risk** – JEN has a duty to minimise safety risks with regard to the design, construction, operation, maintenance and decommissioning of the network to minimise hazards and risks to the safety of any person and damage to property. JEN also must meet reliability of supply obligations. This replacement program identifies likely programs of work to maintain network performance and meet compliance obligations upon asset failure.

JEN also recognises its responsibility to act prudently and efficiently when investing in the distribution network to meet customer and community needs. One way we do this is by adopting asset management practices that put controls in place to test the investment need. Our best practice asset management activities involve balancing costs, opportunities and risks against performance.

In preparing our proposed expenditure, we followed capital expenditure objectives that reflect our customers' expectations, the capital expenditure drivers and capital expenditure objectives and criteria contained in the NER. Our objectives are to:

- Meet customers' expectations that we should maintain our current levels of network reliability at the most efficient cost over the long term;
- Meet our customers' expectations that our network and communities are able to withstand and recover from extreme weather events;
- Manage safety, environmental, electrical system and security risks to as low as practicable and comply with all applicable regulatory obligations efficiently over the long term;
- Connect new customers to the electricity network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers; and
- Optimise exports and imports from distributed energy resources and CER to the distribution network.

1.3 Credible options considered

Table 1 sets out the credible replacement options we have considered.

Table 1: Credible options and summary of economic analysis, $2024

Option	Total capital expenditure ($m)	Value of Customer Reliability ($m)	Ranking
Option 1 – Do nothing	-	-	3

Option	Total capital expenditure ($m)	Value of Customer Reliability ($m)	Ranking
Option 2 - Replacement levels to maintain network performance and reliability and meet compliance obligations	$10.81	$11.50	1
Option 3 - Replacement levels to increase network performance and reliability	$12.97	$13.80	2

1.4 Recommendation

It is recommended that Option 2 is adopted. This option provides the most financially and operationally viable option to mitigate the risks of overhead switchgear failure due to associated risks.

Based on this, a forecast investment of $10.81M is required. This option best meets the long-term interests of our customers and is consistent with the National Electricity Objective and other regulatory obligations.

1.5 Regulatory considerations

The objective of the replacement program is to undertake replacement activities to ensure network performance and to meet compliance obligations, to maintain customer supply reliability across the JEN network given the current condition and future risks associated with overhead switchgear.

JEN's investment decisions are ultimately guided by the National Electricity Objective (NEO). Additionally, JEN is required to meet the requirements of the National Electricity Rules (NER), Victorian Electricity Distribution Code of Practice (EDCoP), and public and industry expectations for distribution system performance, which require capital expenditure objectives to be achieved.

1.6 Financial information

This business case proposes a total capital investment of $10.81M.

This project proposed to be completed by FY31. Table provides the project budget by calendar year.

Table 2: Proposed expenditure by regulatory year, $2024

Regulatory Year	Proposed Expenditure ($M)
FY27	$1.78
FY28	$2.26
FY29	$2.26
FY30	$2.26
FY31	$2.26
Total proposed expenditure	**$10.81**

2. Identified need

2.1 Business and socio-economic context

The HV and LV overhead switchgear is used to facilitate maintenance and construction activity and to reconfigure the network and manage network load. Automated or remote controlled HV gas switches facilitate the remote control of the network and are critical to JEN's future plans for self-healing network capabilities.

The overhead line switchgear asset class includes a variety of pole mounted assets, such as:

- HV air insulated load break switchgear;
- HV gas insulated load break switchgear;
- HV disconnectors (isolators and live line clamps); and
- LV isolators, LV fused isolators, LV ABC isolators and LV ABC fused isolators.

There are approximately 431 HV air break switches, 2,038 HV disconnectors, and 1,317 gas switches installed on the JEN. There are 232 high voltage (HV) feeders on the JEN and each feeder supplies an average of 1,613 customers. Each feeder has an average of 2 air break switches, 9 sets of isolators and 6 gas switches; therefore, a failure to operate can adversely affect the operational efficiency and flexibility of the network.

JEN's gas insulated switches come in two forms, manual and remote-controlled. The remote-controlled units together with remote-controlled Automatic Circuit Breakers (ACR's) are the principal devices used to facilitate the remote control and automation of the distribution network.

There are an estimated 13,000 LV three phase switching devices on the LV overhead network. These are hook stick operated switch links and fused isolators of two types. Those that are bare, generally crossarm mounted, and designed for use with the open wire LV system and those that are insulated and designed for use with aerial bundled conductor LV distribution systems or LV ABC.

On a macro scale it is difficult to distinguish between those that are installed on the overhead LV network and those that are installed in switching cabinets or non-pole type substations.

Table 3 provides details of the number of HV overhead switchgear installations, by type and operating voltage, on JEN's network.

Table 3: HV Overhead Line Switchgear

Overhead Switchgear Type	Operating Volume			Total
	22kV	11kV	6.6kV	
Air Break Switches				
Arc Chute	31		1	32
Ganged Arc Chute	191	3	2	196
Ganged Flicker Blade	144	59		203
Horn Deflector	1			1
HV Disconnectors				
Isolator	1,304	283	187	1,774
Ganged Isolator	1			1
Live Line Clamp	234	28	1	263
Gas Switch	**1,115**	**166**	**36**	**1,317**

Overhead Switchgear Type	Operating Volume			Total
	22kV	11kV	6.6kV	
Total	**3,021**	**539**	**227**	**3,787**

2.2 The identified need and key drivers

2.2.1 Identified need

2.2.1.1 Life Expectancy

As prescribed in *ELE PR 0012 – Network Asset Useful Lives Procedure*, the applicable useful life for HV overhead switches is 50 years and 45 years for LV pole tops (which includes pole mounted LV switchgear).

Asset useful lives are based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has undertaken a number of reviews of asset useful lives utilising consulting agencies and cross-referencing other distribution businesses.[1] With the increasing knowledge and experience on the asset performance of overhead gas switches, manual operated and remote controlled, the useful lives of this asset category within the HV overhead switches family are likely to be reduced in the next review of the procedure.

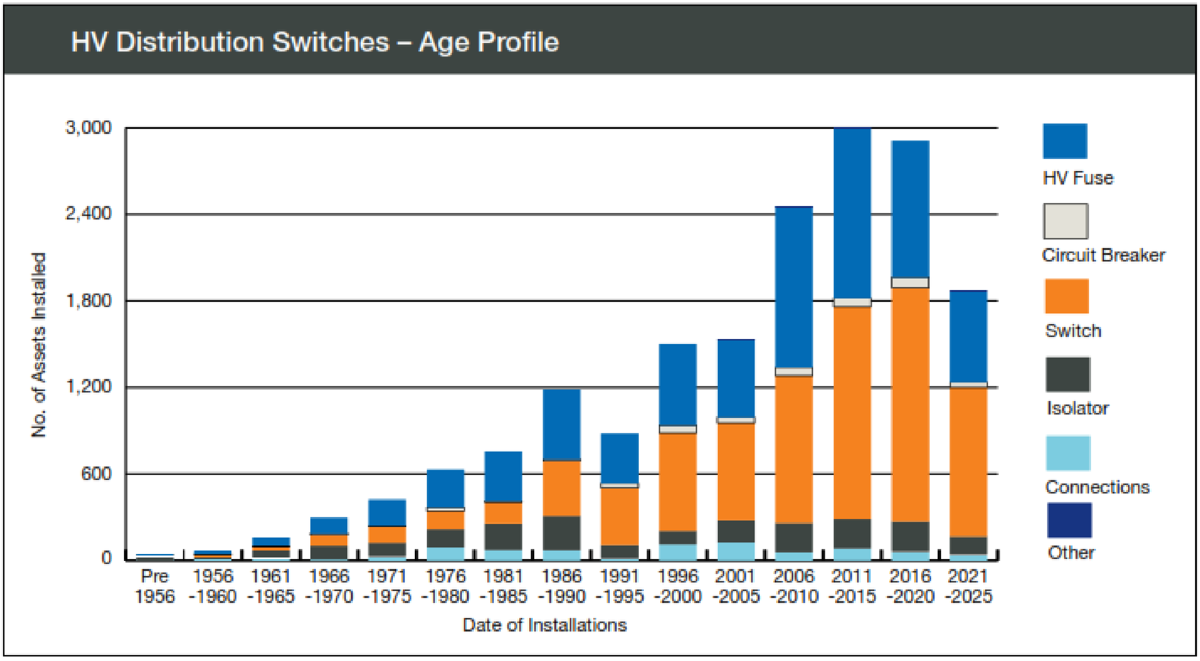
2.2.1.2 Age Profile

There are approximately 3,800 pole mounted HV overhead switches installed on the JEN network. These include air break type switches, disconnectors (isolators and live line clamps) and gas switches. The age profile of the HV overhead switchgear population is shown in Figure 1. Fully enclosed, metal clad, gas insulated load break, fault make, switches have been installed on JEN as standard equipment since 1995. Air break switchgear has not been used as standard since this time due to problems associated with bird and animal strikes and maintenance requirements. A small number of air break switches have been installed since 1995 but it is probable that these are specialised, high capacity, project specific installations.

Consequently, the mix of switch types in this sub asset class is changing with the population of air break load break switches slowly being retired and replaced with gas switches. To a lesser extent this is also happening with HV isolators.

[1] JEN - RP - Support - ELE-999-PR-IN-012 Network Asset Useful Lives Procedure - 20251201 - Public

Figure 1: Age Profile of HV Overhead Switches



2.2.2 Key drivers

2.2.2.1 Age and failure rates

Failure modes for overhead switches include:

- **Failure to operate** - for air break switches this is often due to seized, or misaligned mechanisms, faulty latching mechanism or contact system – and includes defective handles or down rods. For manual gas switches this includes SF6 gas leak and pressure dropped below the lockout threshold. For remote controllable gas switches this includes the failure of the communication or control system.
- **Failure to carry load** - due to deteriorated or high resistance internal components which can lead to thermal overheating and explosive failure.
- **Overheating** - due to high resistance external connections/components which can lead to thermal overheating and damage.
- **Insulation breakdown** – internally due to contamination or lack of SF6, or externally due to insulator or bushing failures.
- **Hardware mechanical failure** – includes failure of operating mechanisms, handles and earthing connections.
- **Failure due to external factors** - includes animal contact and extreme weather condition.
- **Failure due to operational errors or third party** - includes operator not closing and latching the switch properly, and vandalism.

2.2.2.2 Regulatory compliance

Safety and reliability

Consistent with obligations under National Electricity Objective and JEN's commitment to continuous improvement, JEN is recommending the replacement of overhead switchgear upon failure to ensure network performance, reliability, and to meet compliance obligations.

The Electricity Safety Act, s98

The general duty of major electricity companies, including JEN, is to minimise safety risks. Duties of the *Electricity Safety Act 1998* (ESA) which requires a Major Electricity Company (MEC) to design, construct, operate, maintain and decommission its supply network to minimise As Far As Practicable (AFAP) the hazards and risks to the safety of any person, damage to the property and the bushfire danger arising from the supply network.

Relevant standards

The requirements for all new overhead line switchgear are set out in JEN's technical specification for the purchase of this equipment. This specification sets out the performance standards to be met and the design features of the switchgear. The specification references a number of Australian Standards. Unless otherwise specified, all HV overhead line switchgear shall be designed, manufactured and tested in accordance with Australian Standards set out in Table 4.

Table 4: Relevant Australian Standards

Standard	Title
AS 1852.441	International Electrotechnical Vocabulary – Switchgear, Control gear and Fuses
AS/NZS 60265.1	High-Voltage Switches – Switches for Rated Voltages above 1kV and less than 52kV
AS 62271.1	High-voltage switchgear and control gear – Common specifications
AS 62271.200	High-voltage switchgear and control gear – A.C. metal-enclosed switchgear and control gear for rated voltages above 1kV and up to including 52kV
AS 62271.102	High-voltage switchgear and control gear – Part 102 Alternating current disconnectors and earth switches
AS/NZS IEC 60947.3	Low-voltage switchgear and control gear – Switches, disconnectors, switch-disconnectors and fuse-combination units

The equipment must be able to operate with the required performance parameters when exposed to climatic conditions in the state of Victoria.

Investment decisions

In line with the NEO, JEN's investment decisions aim to maximise the NPV to electricity consumers. The objective of this project is to maintain the reliability of supply to customers, given the current condition of the assets. This strategy must align with other JEN strategies and plans, and the project must comply with associated regulatory requirements.

JEN's investment decisions are ultimately guided by the NEO. Additionally, considerations such as the capital expenditure objectives set out in the NER (clause 6.5.7) are particularly relevant to JEN's investment decisions:

> *a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):*

(1) Meet or manage the expected demand for standard control services over that period

(2) Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services

(3) To the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) The quality, reliability or security of supply of standard control services; or

(ii) The reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) Maintain the quality, reliability and security of supply of standard control services

(iv) Maintain the reliability and security of the distribution system through the supply of standard control services.

(4) Maintain the safety of the distribution system through the supply of standard control services.[2]

Additionally, the EDCoP sets out provisions relevant to JEN's planning, design, maintenance, and operation of its network, most notably section 19.2 (Good Asset Management) and section 13.3 (Reliability of Supply):

<u>Section 19.2 – Good Asset Management</u>

A distributor must use best endeavours to:

a) Assess and record the nature, location, condition and performance of its distribution system assets

b) Develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:

- *To comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code*
- *To minimise the risks associated with the failure or reduced performance of assets*
- *In a way which minimises costs to customers taking into account distribution losses.*

c) Develop, test or simulate and implement contingency plans (including where relevant plans to strengthen the security of supply) to deal with events which have a low probability of occurring, but are realistic and would have a substantial impact on customers.

<u>Section 13.3 – Reliability of Supply</u>

A distributor must use best endeavours to meet targets determined by the AER in the current distribution determination and targets published under clause 13.2.1 and otherwise meet reasonable customer expectations of reliability of supply.

When making decisions to invest, JEN must comply with these obligations.

2.2.3 Proposed replacement programs and activities

Our proposed expenditure is informed by specific activities, each assigned to service codes (in brackets):

[2] NER, cll 6.5.6(a), 6.5.7(a).

Program & Service Code	Activities
Gas Switch Replacement (RHG)	Replacement of an existing Manual Gas Switch (MGS) or Remote Controlled Gas Switch (RCGS with a new RCGS, as a result of a fault or operational damage, which includes: • All cable connections and fittings for RCGS, if required • Switch mounting arm • Connections • Bird/animal proofing of equipment and structure • Testing of HV earth while on site • Disposal of defective switchgear and SF6 • Check and tighten all hardware on the same structure • Commissioning and de-commissioning works The activity excludes: • Crossarm replacement • Surge arrestor • HV fuse units
HV Isolators (RHH)	Replacement of a set of HV isolators and all associated hardware, on a single structure, as a result of: • A fault or operational damage • Erection of new isolators to facilitate network requirements • Supply of isolator and all bridging • Includes all cable connections and fittings The activity excludes: • Replacement of crossarms to facilitate the creation a strain point
LV Isolators (RHL)	Replacement of a set of LV isolators and all associated hardware, on a single structure, as a result of: • A fault or operational damage • Erection of new isolators to facilitate network requirements The activity includes: • All wiring • Isolator and materials • IPC's and Stalk Lugs • Visual inspection and tightening of loose hardware • All cable connections and fittings The activity excludes: • FOLCB replacement, or for replacement of fuse carriers, bases or wedges

2.3 Asset risk (or opportunity) analysis

2.3.1 Short description of the affected Jemena assets

2.3.1.1 Current risks

Current risks for overhead switchgear assets include:[3]

- **Age of air break switch population** - Given the age of the air break switch population and the ongoing maintenance requirements, only minor corrective maintenance will be undertaken as a result of the inspection program. In all cases wherever significant component replacement, adjustment or repair is required, the air break switch shall be replaced with a gas switch or an ACR;

[3] Refer to Appendix A.

- **Recurring issues on 22kV air break switches** - This includes adjustments needed as a result of incorrect installation, the early use of green timber segments in operating rods, operating handle diameters, or the earthing of operating handles, brown insulators and identification plates.
- **ABB HV isolator failures** - In late 2003, the first of a series of ABB HV isolator failures was observed with the mode of failure being cracks forming on the porcelain insulator. These cracks resulted from corrosion of the supporting pin where it was cemented into the insulator. The cracks caused the insulator to fail mechanically, resulting in breakage often when the isolator was being operated.
- **Non-latched NGK HV isolator failure** - From approximately 2002 to 2009 the make of HV isolator used was a non-latched NGK model. In 2009 a number of outages were attributed to non-latched isolators 'falling' open. Upon investigation it was suspected that bolts that had not been sufficiently tightened during manufacturing were allowing the isolators to be closed incorrectly (too much lateral movement in the arm). The manufacturer, NGK, changed their isolator design to one with a latching mechanism when closing and is now standard design.
- **Manual handing issues** - These are always present in the operation of overhead switches, in particular switches that are operated by an operating rod and handle from ground level. Older switches can become stiff and difficult to operate. Safe operating procedures and correct manual handing practices are mandatory for operating any switch and adherence to these practices mitigates potential health and safety risks. The increased use of manual gas switches also improves the conditions for field staff required to operate a switch.
- **NGK remote controlled gas insulated load break switches** - NGK remote controlled gas insulated load break switches with new control box model GSS100 REV2 have had three inadvertent opening of the switches without the command signal sent since the installation started in late 2021. It has also been found that 27 control box batteries suffered swelling since installation due to overcharge as a result of a new battery charging circuit design. The supplier recommended to install a voltage limiting cable (VLC) in series with the charging circuit to prevent overcharging the battery.

2.3.1.2 Future risks

There is a growing risk for single phase switching to create capacitive current flow of sufficient capacity to trip the sensitive earth fault protection on a feeder. Single phase switching of any network segment with a significant length of three phase underground cable disrupts the normally balanced and self-cancelling capacitance in the cable resulting in capacitive current flow to earth.

With the increasing utilisation of underground cables in JEN network, the potential for single phase switching to create capacitive current flow of sufficient capacity to trip the sensitive earth fault protection on a feeder is substantial and potentially growing. This in turn can result in the unplanned interruption of customer supplies.

JEN has ceased the installation of new HV isolators in favour of remote-control switches (RCS) or ACR's on the distribution network. This will ensure the progressive movement away from single-phase switching on the JEN network, however, care will still need to be taken with the legacy installations of HV isolators and the increasing installation of underground cable.

2.3.2 Asset condition and risk assessment

Within our Asset Class Strategy, [4] the overhead HV switchgear sub-asset class has an asset criticality score of AC1 (Low) due to the consequence rating being minor. Similarly, LV switchgear has a low criticality score due to the minor consequence of a failure.

Overhead line switchgear impacts JEN's overall network reliability and Service Target Performance Incentive Scheme (STPIS) via the minimisation of customer numbers off supply during an unplanned outage.

[4] JEN – RIN – Support – Electricity Distribution Asset Class Strategy – 20250131 – Public.

2.4 Consistency with Jemena strategy and plans

This section describes how this project is consistent with JEN’s objectives and strategies:

- **Provision of Service Levels and Reliability:** Ensuring service levels and reliability meet customer expectations.
- **Modern Capabilities:** Deployment of modern equivalent capabilities in the network to remain relevant to customers in the longer term.
- **Prudent and Efficient Expenditure:** Ensuring expenditure is prudent and efficient, aligning with customer expectations regarding affordability.

JEN seeks to ensure that lifecycle costs are both efficient and effective. This business case is consistent with this requirement and aligns with the long-term vision of the network, as set out in the Asset Management Plan (AMP) and annual planning reports.

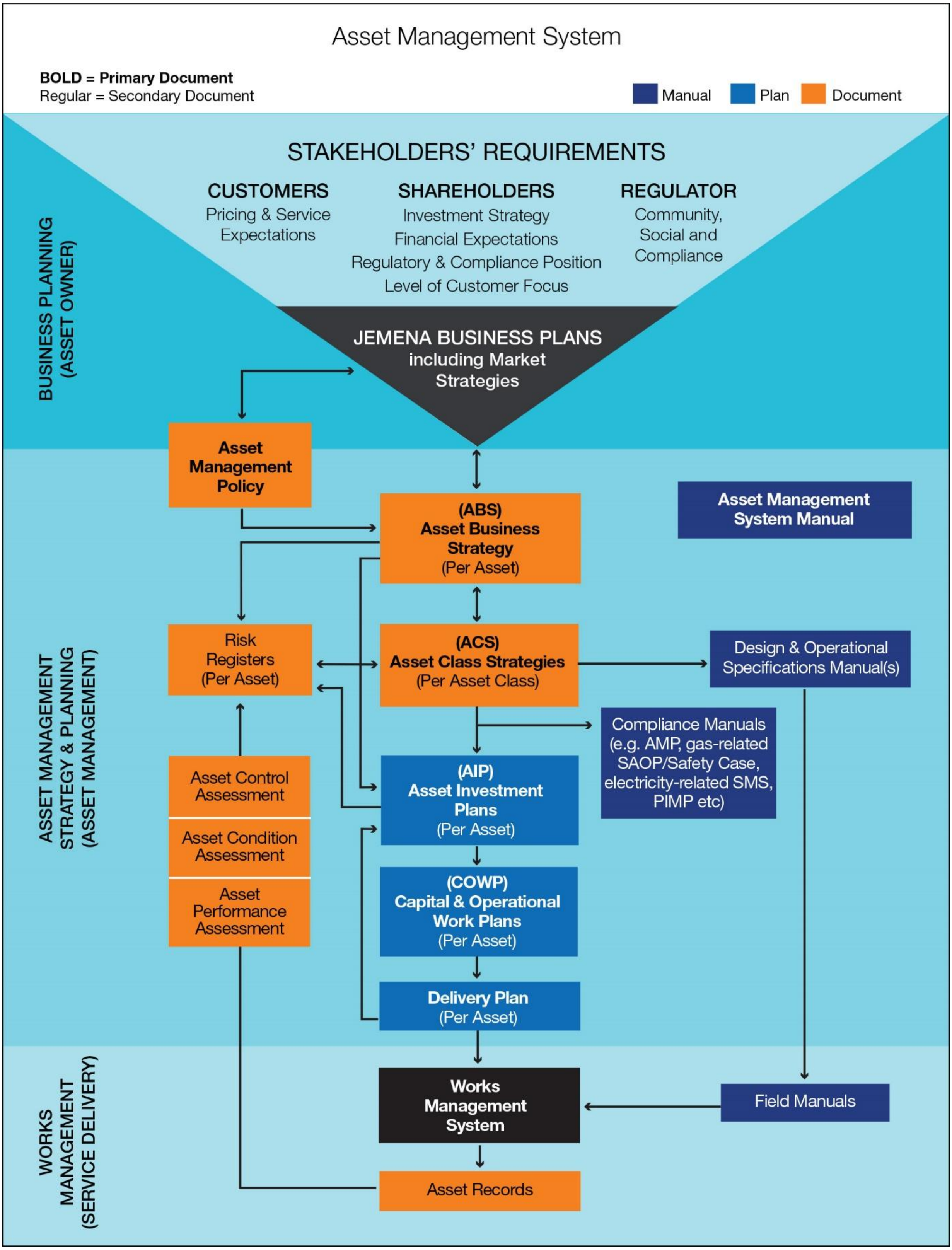
This proposal aligns with Asset Management Strategies, Plans and Policies contributing to a safe workplace for JEN employees and contractors. By addressing identified issues, JEN can reduce the risk of injury or environmental incident.

JEN abides by Australian asset and risk management industry standards (ISO 55001 and ISO 31000:2018) which is part of JEN's internal risk and asset management framework documents (ELE PL 0004 and JAA PO 0050).

Figure 2 outlines the Jemena asset management system and where the Asset Management Plan (AMP) is positioned within it. The AMP covers the creation, maintenance and disposal of assets including investment planned to augment network capacity to meet increasing demand and to replace degraded assets to maintain reliability of supply to meet Jemena Business Plan requirements.

This strategic framework facilitates the planning and identification of business needs that require network investment documented via business cases.

Figure 2: The Jemena Asset Management System



JEN also recognises its responsibility to act prudently and efficiently when investing in the distribution network to meet customer and community needs. One way we do this is by adopting asset management practices that put controls in place to test the investment need. Our best practice asset management activities involve balancing costs, opportunities and risks against performance.

In preparing our proposed expenditure, we followed capital expenditure objectives that reflect our customers' expectations, the capital expenditure drivers and capital expenditure objectives and criteria contained in the NER. Our objectives are to:

- Meet customers' expectations that we should maintain our current levels of network reliability at the most efficient cost over the long term;
- Meet our customers' expectations that our network and communities are able to withstand and recover from extreme weather events;
- Manage safety, environmental, electrical system and security risks to as low as practicable and comply with all applicable regulatory obligations efficiently over the long term;
- Connect new customers to the electricity network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers; and
- Optimise exports and imports from distributed energy resources and CER to the distribution network.

3. Comparison of credible options

3.1 Identifying credible options

The following feasible options could be considered to address the identified need:

1. **Option 1 is 'do nothing'**, which assumes business as usual, continuing current maintenance activities such as inspections, condition monitoring, preventive maintenance and defect repairs. This is limited to maintenance rather than complete overhead switchgear replacement. This option does not address any of the identified condition issues in full nor does it allow us to maintain current levels of network reliability.

2. **Option 2 is 'replacement levels to maintain network performance, reliability and to meet compliance obligations'**. This option optimises replacement levels to ensure current levels of network reliability whilst responding to our customers who have indicated they value a stable network. This is evidenced by our customer engagement, which highlights 'maintaining the network' being more important to customers than 'improving the network'. When assessing this option, we calculated a value of customer reliability (VCR) metric to determine the average value different types of our customers place on having reliable electricity supply.[5] The VCR calculated, applicable to the average customer, was determined to be $11.50M over 5 years.

3. **Option 3 is 'replacement levels to increase network performance and reliability'**. This approach would focus on proactively replacing overhead switchgear with the intention of *improving* network reliability. As with Option 2, when assessing this option we calculated a value for VCR to determine the average value different types of our customers place on having reliable electricity supply.[6] The VCR calculated was determined to be $13.80M over 5 years.

3.2 Developing credible options

Table shows the extent to which each option addresses the identified issues.

Table 5: Credible Options Analysis

Issue	Option 1	Option 2	Option 3
Asset risk The key issues associated with overhead switchgear are failure to operate, failure to carry load, overheating, insultation breakdown, hardware mechanical failure, failure due to external factors and failure due to operational errors or by third parties.	○	●	●
Regulatory risk JEN has a duty to minimise safety risks with regard to the design, construction, operation, maintenance and decommissioning of the network to minimise hazards and risks to the safety of any person and damage to property. JEN also must meet reliability of supply obligations.	○	●	●

●	Fully addressed the issue
◑	Partially addressed the issue
○	Did not address the issue

[5] More detail on how this has been calculated can be found in 4.1.1

[6] More detail on how this has been calculated can be found in 4.1.1

Each of these options are discussed in detail below.

3.2.1 Option 1: Do nothing

The 'do nothing' option assumes business as usual, continuing current maintenance activities such as inspections, condition monitoring, preventive maintenance and defect repairs. However, this option does not address any of the identified condition issues, given it does not undertake overhead switchgear replacement. The probability of failure for this equipment would continue to increase over time, potentially leading to catastrophic failure while in service. Given the criticality of these issues and the lack of risk mitigation, this option is not considered credible.

3.2.2 Option 2: Replacement levels to maintain network performance, reliability and to meet compliance obligations

The 'replacement levels to maintain network performance, reliability and meet compliance obligations' option is an approach which invests in the replacement of overhead switchgear where failure has occurred.

Replacing overhead switchgear as required assists in mitigating consequences associated with a failure of this type of asset, which are designed to 'run to failure'.

This option would maintain current levels of network reliability and optimises replacement levels to maintain this reliability whilst responding to our customers who have indicated they value a stable network more so than improvements to the network. This is evidenced by our customer engagement, which highlights 'maintaining the network' being more important to customers than 'improving the network'.[7]

Jemena's Peoples Panel noted 'Jemena needs to prioritise investing in reliability by assessing, building, and maintaining the network to meet changes in operating conditions and withstand network failures'.[8] This position was reiterated by the First Nations and Disability Customer Voice Groups.

When assessing this option, we calculated a value of customer reliability (VCR) metric to determine the average value different types of our customers place on having reliable electricity supply.[9] The VCR calculated, applicable to the average customer, was determined to be $11.50M over 5 years.

This option is likely to resolve most identified issues while aligning with the JEN asset class and business strategies. The total capital cost of this option is forecasted at $10.81M based on activities commencing in FY2027. This option is preferred given historic failure rates and the age of assets proposed to be replaced.

As detailed in this business case, several individual programs of work have been identified to ensure that we maintain network performance, reliability and address our compliance requirements. Forecast replacement volumes and expenditure proposed under Option 2 is set out in Table.

Table 6: Option 2 Replacement Volumes and Expenditure – Switchgear

Service Code	Activity	Forecast Replacement Volumes					Proposed Expenditure ($2024, '000)					
		FY27	FY28	FY29	FY30	FY31	FY27	FY28	FY29	FY30	FY31	Total
RHG	Gas Switch Replacement	12	26	26	26	26	327.25	684.62	684.62	684.62	684.62	**3,066**
RHH	HV Isolators Replacement	68	68	68	68	68	457.41	457.41	457.41	457.41	457.41	**2,287**
RHL	LV Isolator Replacement	150	150	150	150	150	399.80	399.27	398.86	399.41	399.75	**1,997**

[7] See JEN - Att 02-01 Customer engagement – 20250131.

[8] See JEN - Att 02-01 Customer engagement – 20250131, s.5.1.

[9] More detail on how this has been calculated can be found in 4.1.1.

Service Code	Activity	Forecast Replacement Volumes					Proposed Expenditure ($2024, '000)					
		FY27	FY28	FY29	FY30	FY31	FY27	FY28	FY29	FY30	FY31	Total
RHH	ACR Replacement	6	6	6	6	6	199.98	199.98	199.98	199.98	199.98	**999.91**

N.B. Total figures have been rounded.

3.2.3 Option 3: Replacement levels to increase network reliability

The 'replacement levels to increase network performance and reliability' option is a proactive approach that invests in at-risk replacement of overhead switchgear over and above what is required to maintain current levels of reliability. This approach would focus on replacing the highest risk overhead switchgear.

Generally, this option would include a variety of sub-options for determining when replacement occurs:

- **Replacing overhead switchgear at a scheduled age**. Although the scheduled replacement age will be based on structured analysis of the functions and potential failures, for assets such as overhead switchgear, age based replacement is not an optimal strategy and not cost effective.

- **Scheduled testing of overhead switchgear to ascertain their conditions**. The incremental improvement in network reliability does not outweigh the cost to test the overhead switchgear.

This option is likely to resolve most identified issues in terms of age and condition. The total capital cost of this option is $12.97M.

This option would replace assets at a rate above historical trend forecasts, to *improve* network reliability above current levels. This option does not respond to our customer's needs, who have indicated they value a stable network more so than improvements to the network. This is evidenced by our customer engagement, which highlights 'maintaining the network' being more important to customers than 'improving the network'.[10] Jemena's Peoples Panel noted 'Jemena needs to prioritise investing in reliability by assessing, building, and maintaining the network to meet changes in operating conditions and withstand network failures'.[11] This position was reiterated by the First Nations and Disability Customer Voice Groups.

As with Option 2, when assessing this option we calculated a value for VCR to determine the average value different types of our customers place on having reliable electricity supply.[12] The VCR calculated, applicable to the average customer, was determined to be $13.80M over 5 years.

Forecast replacement volumes and expenditure proposed under Option 3 is set out inTable

Table 7.

Table 7: Option 3 Replacement Volumes and Expenditure – Switchgear

Service Code	Activity	Forecast Replacement Volumes					Proposed Expenditure ($2024, '000)					
		FY27	FY28	FY29	FY30	FY31	FY27	FY28	FY29	FY30	FY31	Total
RHG	Gas Switch Replacement	15	31	31	31	31	392.70	821.54	821.54	821.54	821.54	**3,679**
RHH	HV Isolators Replacement	82	82	82	82	82	548.89	548.89	548.89	548.89	548.89	**2,744**

[10] See JEN - Att 02-01 Customer engagement – 20250131.

[11] See JEN - Att 02-01 Customer engagement – 20250131, s.5.1.

[12] More detail on how this has been calculated can be found in 4.1.1.

Service Code	Activity	Forecast Replacement Volumes					Proposed Expenditure ($2024, '000)					
		FY27	FY28	FY29	FY30	FY31	FY27	FY28	FY29	FY30	FY31	Total
RHL	LV Isolator Replacement	180	180	180	180	180	479.76	479.13	478.64	479.29	479.70	**2,397**
RHH	ACR Replacement	7	7	7	7	7	239.98	239.98	239.98	239.98	239.98	**1,200**

N.B. Total figures have been rounded.

4. Option analysis

4.1 Economic analysis

In line with the objective of the National Electricity Rules, JEN's capex investment decisions aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market.

To assess benefits against this objective, JEN has undertaken a probabilistic cost-benefit assessment of replacement options that considers the likelihood and severity of critical network outages. This methodology assesses the expected impact of asset failures and subsequent network outages on supply delivery and combines this with the value customers place on supply reliability (VCR) and compares the result with the costs required to reduce the likelihood and/or impact of these supply outages. The benefits considered in this economic analysis relate to mitigating the increasing risk of overhead switchgear failure within the electricity distribution network. This includes the safety risks associated with Option 1 (do nothing) described earlier. The following table summarises the economic analysis undertaken.

Table 8 outlines the costs and VCR values associated with each option.

Table 8: Costs of Options, $2024

Option	Total capital expenditure ($m)	Value of Customer Reliability ($m)	Ranking
Option 1 – Do nothing	-	-	3
Option 2 - Replacement levels to maintain network performance and reliability and meet compliance obligations	$10.81	$11.50	1
Option 3 - Replacement levels to increase network performance and reliability	$12.97	$13.80	2

4.1.1 Assumptions and inputs used

Value of unserved energy analysis

- This business case determines the value of unserved energy based on the historical level of replacements for Option 2 and an increase in volumes from historical levels in Option 3. The value of unserved energy is determined by the average duration that customers experience an outage due to an underground cable fault converted to consumption and using the 2025 VCR in $/kWh to calculate the monetary value of the unserved energy. These values are set out in Table 9 and Table 10.

Table 9: Estimate of customer unserved energy per hour

Sector	kWh
Residential	0.70
Commercial	1.67
Industrial	16.67

Table 10: AER VCR Final Report

Sector	2025 VCR - $/kWh
Residential	54.41
Agricultural	22.25
Commercial	34.39
Industrial	33.49
>10MVA	70.88

4.2 Financial analysis for the preferred option

4.2.1 Financial analysis

This business case proposes a total capital investment of $10.81M.

This project proposed to be completed by FY31. Table 11 provides the project budget by calendar year.

Table 11: Proposed expenditure by regulatory year, $2024

Regulatory Year	Proposed Expenditure ($M)
FY27	$1.78
FY28	$2.26
FY29	$2.26
FY30	$2.26
FY31	$2.26
Total proposed expenditure	**$10.81**

5. Recommendation

It is recommended that Option 2. This option provides the most financially and operationally viable option to mitigate the risks of overhead switchgear failure due to associated risks.

Based on this, a forecast investment of $10.81M is required. This option best meets the long-term interests of JEN customers and is consistent with the National Electricity Objective and other regulatory and compliance obligations.

Appendix A – HSE Gram

HSE Gram

HSEG 23-13 HV Switchgear Operational Status Update Summary

Prior to operating any high voltage (HV) switchgear on the Powercor/CitiPower networks, (Distribution and/or zone substation) the operator shall confirm with the System Control Centre (SCC) to determine if there are any electronic Caution Refer Operation (CRO) tags on the switch.
There are two types of CRO tags associated with HV Switchgear:

- CRO Tag Operable
- CRO Tag Inoperable

CRO Tagged Operable:

No person shall operate electrical apparatus that has a CRO tag attached until the operator has contacted the SCC and confirmed the reason for the attached CRO tag. Upon careful consideration of the information received from the SCC, and a thorough assessment and inspection of the electrical apparatus on site, an Authorised Electrical Operator may operate the electrical apparatus if considered safe to do so.

CRO Tagged Inoperable:

No person shall operate electrical apparatus that has a CRO tag and is recorded as inoperable in the SCC register, until the electrical apparatus has been proven de-energised, and there is deemed to be no further risk to personnel, the public, or other electrical apparatus because of the operation.

Note: The switch may also not be operable in a dead condition e.g., switch has cracked/broken insulators.

Removing a CRO tag:

Immediately upon completion of repairs or corrective action maintenance and testing to confirm the correct operation of the equipment, the Authorised Electrical Operator shall under the direction of the Network Controller remove the CRO tag.

Further information on HV switchgear can be found in the two maintenance policies listed below:

550 Outdoor Distribution HV Air Break Switchgear

554 Indoor Distribution HV Air Break Switches and Isolators

And the

CitiPower Powercor Switchgear Operating Manual

The table overleaf provides an updated summary of the Operational Status of HV Distribution switchgear on the Powercor/CitiPower Networks as of 20/04/2023.

Zone substation switchgear is not included in the restrictions in this table.
The switchgear inside a zone substation is referenced in the **Network Asset Maintenance Policy for Zone Substation outdoor type air insulated bus, switches, and isolators** which is currently under review.

For further information contact the Investigation and Authorisations Team leader.

HSE Gram

Asset Type	Asset class	Reference material	Operational Status
Overhead.	Gas Switch pole mounted - NGK or Schneider type.		• No change for NGK or Schneider gas switches, OK to operate as normal. • Any gas switch with low gas is not to be used as an isolation point.
Overhead	Gas Switch pole mounted -ABB NXA type		• ABB NXA gas switches do not have separate gas gauge indicator. • If an ABB gas switch is required to be used as an isolation point and is already Open, it must be closed and then opened to confirm low gas lockout has not operated.
Overhead	HV Air-Break Switch pole mounted – GEVEA type -	RA 22-09 GEVEA Switch Operation	• GEVEA switches within the 10-year maintenance cycle can be operated as normal, including in high pollution/coastal areas • GEVEA switches beyond the 10-year maintenance cycle are to be CRO'd Inoperable • When operating GEVEA switches from the ground, the use of anything other than a rigid HV operating stick (and extension, if required) will cease
Overhead	HV Air-Break Switch pole mounted – Non-GEVEA ABS (Stanger and Taplin) which include GAC and other ABS types -		• Non-GEVEA ABS within the 10-year maintenance cycle can be operated as normal • Non-GEVEA ABS beyond 10-year maintenance cycle are to be CRO'd Inoperable • Non-GEVEA ABS fitted with expulsion interrupters to remain CRO'd inoperable
Overhead	HV Isolators.		• No operational change, OK to operate as normal
Overhead	Fuse Savers.	RA 23-03 Siemens 3AD8 Fusesaver SWER ACR OCO Battery Level	• No operational change, OK to operate as normal
Overhead	ACRs – Vacuum interrupter.	RA 23-06 Automatic Circuit Reclosers (ACRs) as Isolation Points	• As an interim measure until the findings of the risk assessment are known, the use of urban ACRs as a point of isolation (where no isolators are installed) is suspended.
Overhead	ACRs -Oil.		• No operational change, OK to operate as normal.
Indoor	HV ABS Indoor Dist. Substations - Including GAC and other AB types.		• Stanger Single Phase Arc Chute and Stranger SCD GAC (Type 1 and 2) no operational change, OK to operate as normal • Calor Emag/TSN and Gardy are now CRO'd Inoperable • SIEMENS H251 GAC, outdoor switchgear when mounted indoors, TSN GMH GAC, BBC K-MEC and A-MEC switches. These are obsolete and remain CRO'd Inoperable until eliminated from the network
Underground	Ring Main Units (RMU) Oil.		• Solar Basic and AGE/AEI OW5 & FP BR4 oil switches are obsolete and CRO'd Inoperable. All other types are OK to operate as normal
Underground	Ring Main Units (RMU) Sf6.	RA 23-10 Update to Metal clad switch gear without a gas indicator gauge	• SF6 metal clad switches without gas gauges or defective gauges to be CRO'd Operable when de-energised or when wearing CAT 4 PPE. 'RA 22-13 Metal clad switch gear without a gas indicator gauge' will be updated to reflect the agreed change.
Underground/ Indoor	Kiosk in Tank HV Oil Switches		• No operational change, OK to operate as normal