CITIPOWER

ASSET CLASS OVERVIEW

DISTRIBUTION SWITCHGEAR

CP BUS 4.07 – PUBLIC
2026–31 REGULATORY PROPOSAL

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1. Overview

Distribution switchgears are critical to our ability to maintain network reliability, as they allow us to safely and efficiently minimise the impact of disruptions to customers in response to planned and unplanned outages.

Just over half of our distribution switchgear forecast interventions for the 2026–31 regulatory period are driven by distribution switchgear defects and faults. These are forecast based on historical annual asset defect rates and forecast asset population, consistent with independent statistical analysis on the best fit of our historical data.

Our forecast also includes two risk-based replacement programs to address specific safety and network reliability risks posed by the operation of a subset of our high voltage (HV) air-break switches (ABS), and ring main units (RMUs) that are without oil or gas gauges. The safe operation of our distribution switchgear is a critical concern in the ongoing management of our distribution switchgear—for example, if our field crew operate switchgear with insufficient oil or gas insulation, it can result in catastrophic failure of the switchgear that can result in injury or death.

These safety concerns have been raised by our operators, the Electrical Trades Union and WorkSafe Victoria, and have led to the CRO-tagging of these RMUs.[1]

Our risk-based programs will manage the replacement of this switchgear over a 10-year period.

A summary of our forecast expenditure for distribution switchgear for the 2026–31 regulatory period is set out in table 1.

TABLE 1 DISTRIBUTION SWITCHGEAR: EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
Defective switches	6.9	6.0	5.9	6.1	6.1	31.0
Defective fuses and surge diverters	0.2	0.2	0.2	0.2	0.2	1.2
Inoperable HV ABS program	1.1	1.1	1.1	1.1	1.1	5.7
Inoperable RMU program	2.8	2.8	2.8	2.8	2.8	13.9
Total	**11.1**	**10.2**	**10.1**	**10.2**	**10.3**	**51.9**

Note: Expenditure presented above will not exactly match the Reset RIN due to the allocation of some works across multiple asset categories.

[1] CRO-tagging notifies operators that the switch is defective, and limits the operational ability for the switch to be opened.

2. Background

Distribution switchgears are manual or motorised mechanical devices that enable the connection and disconnection of high voltage (HV) and low voltage (LV) circuits. They are key to the connection and disconnection of sections of the network for isolating network faults to minimise disruption of electricity supply to customers, managing load and planned work.

This asset class also includes fuses and surge diverters.

This section provides an overview of our distribution switchgear asset class, including a high-level summary of our compliance obligations, asset population and age profile.

2.1 Our compliance obligations

We operate under a combination of national and state legislation which establish our obligations and the regulatory framework under which we operate.

The National Electricity Rules sets out reliability and safety obligations and the Electricity Distribution Code of Practice include performance requirements. We must also manage our network assets in accordance with the Electricity Safety Act 1998, the Electricity Safety (Management) Regulations 2019, the Electricity Safety (Bushfire Mitigation) Regulations 2023 and the Victorian Environment Protection Act 2017.

These obligations can be summarised as follows:

- Electricity Safety Act 1998 – requires us to minimise safety risk 'as far as practicable' including bushfire danger
- Electricity Distribution Code of Practice – requires us to manage our assets in accordance with principles of good asset management and to minimise the risks associated with the failure or reduced performance of assets
- National Electricity Rules – requires us to forecast expenditure to maintain the quality, reliability and security of supply of our networks and maintain the safety of the distribution system
- Victorian Environment Protection Act (2017) – requires us to reduce the risk of harm from our activities to human health and the environment and from pollution or waste.

In short, we must maintain reliability, minimise safety risk 'as far as practicable' including bushfire danger arising from our network, and reduce the risk of harm to the environment.

2.2 Asset population and age

Our distribution switchgear population includes a combination of pole-mounted and ground-mounted switchgear, with the majority of these being pole-mounted. As shown in table 2, these comprise automatic circuits reclosers (ACRs), ring main units (RMUs), air-break switches (ABS), outdoor gas switches, LV and HV circuit breakers, and HV isolators.

TABLE 2 DISTRIBUTION SWITCHGEAR POPULATION

SWITCHGEAR TYPE	VOLUME
Air-break switches	1,806
Automatic circuit reclosers	41
HV isolators	875
HV and LV circuit breakers	2,828
Outdoor gas switches	404
Ring main units (SF6 gas)	4,026
Total	**9,980**

Most of our ACR, gas switches and RMUs were replaced recently, and age data is recorded in our systems. However, age data is not available for a significant portion of our distribution switchgear due to poor historical data records—noting air-break switches have been installed since the 1930s—and a lack of physical data stamps on these assets.

Our distribution switchgear asset class also includes some low value assets, such as fuses and surge arrestors. We do not have age profile information available for these, however, given their low value and our asset management approach to these assets (i.e. these assets are typically run to failure).

3. Identified need

The performance of our distribution switchgear asset class may lead to a loss of supply for customers, pose safety risks to our personnel and the public, potential fire starts, and potentially pollute the environment if there is an oil or sulphur hexafluoride (SF6) leak.

The inoperability of many of our distribution switchgear types is also increasingly limiting the operational flexibility of our network, leading to delayed supply restoration for some customers and/or increased scope of planned outages. The impact of this will increase over time with further electrification.

The identified need, therefore, is to manage our distribution switchgear asset class to maintain reliability and minimise safety risks as far as practicable, consistent with our regulatory and legislative obligations.

This section outlines the historical performance of our distribution switchgear, which has informed how we assess (and respond, as required to) this identified need.

3.1 Historical asset performance

In assessing the need to intervene on our distribution switchgear, we monitor several asset performance indicators, including asset failures, high priority defects, and asset condition.[2] These indicators inform our underlying asset management response—for example:

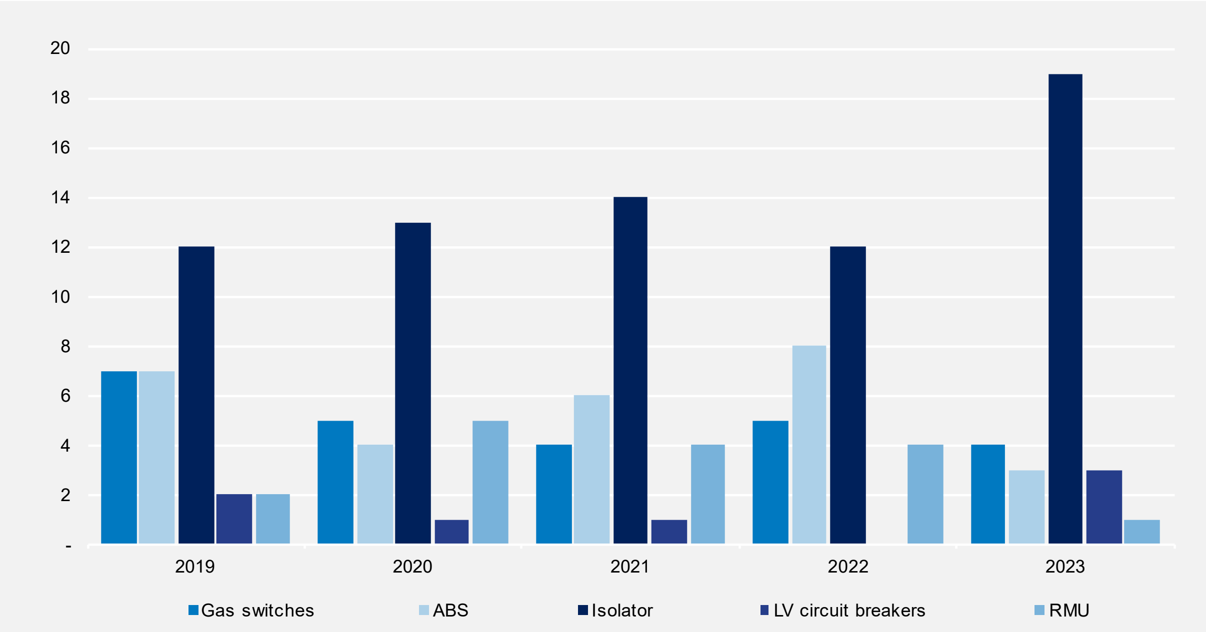
- increasing unassisted asset failures indicates a likely need to act immediately and review asset management practices (noting that robust inspection practices and governance over the application of these methods may drive low failure rates, but if the underlying condition of the relevant asset population is poor and/or deteriorating, high and/or increasing intervention volumes may still be prudent and efficient)
- increasing high-priority defects or deteriorating condition (relative to asset management thresholds) indicates a likely need to act soon to increase interventions over time, and/or undertake risk-based assessments.

3.1.1 Historical asset failures

As shown in figure 1, our distribution switchgear failures have been relatively stable from 2019 to 2023. The majority of distribution switchgear failures are isolator failures, which have been increasing. However, isolators are run to failure given their low cost.

[2] This section does not consider fuses and surge diverters, given their low value and our asset management approach to these assets (i.e. these assets are typically run to failure)

FIGURE 1 DISTRIBUTION SWITCHGEAR: FAILURES



3.1.2 Historical asset defects

Consistent with our regulatory obligations, we inspect our distribution switchgear located in low bushfire risk area (LBRA) every five years. These cyclic inspections provide snapshots in time of the distribution switchgear condition and identify any defects.

Our response to identified defects depends on the nature and severity of the defect, and may include more frequent re-inspections. High priority defects that result in intervention are shown in table 3.

TABLE 3 RESPONSE TIMEFRAMES FOR HIGH PRIORITY DEFECTS

PRIORITY	TIMEFRAME FOR INTERVENTION
P1	Make safe within 24 hours of identification (replacements or repairs can occur beyond the initial 24 hours)
P42	Addressed within 42 days of identification
P2	Addressed within 32 weeks of identification

As shown in in figure 2 and figure 3, the number of high priority switchgear defects have been increasing since 2019.[3] This increase is driven by our RMU defects. The main driver of RMU defects are oil leaks from legacy oil filled RMUs and low gas for modern gas filled RMUs. ABS defects have not increased due to the restricted operation of a large proportion of them due to safety reasons. Most ABS defects are identified during operation.

[3] These defect volumes exclude thermal defects due to issues with our data capture process. Total actual defect volumes, therefore, are higher than shown.

FIGURE 2 DISTRIBUTION SWITCHGEAR: DEFECTS BY PRIORITY

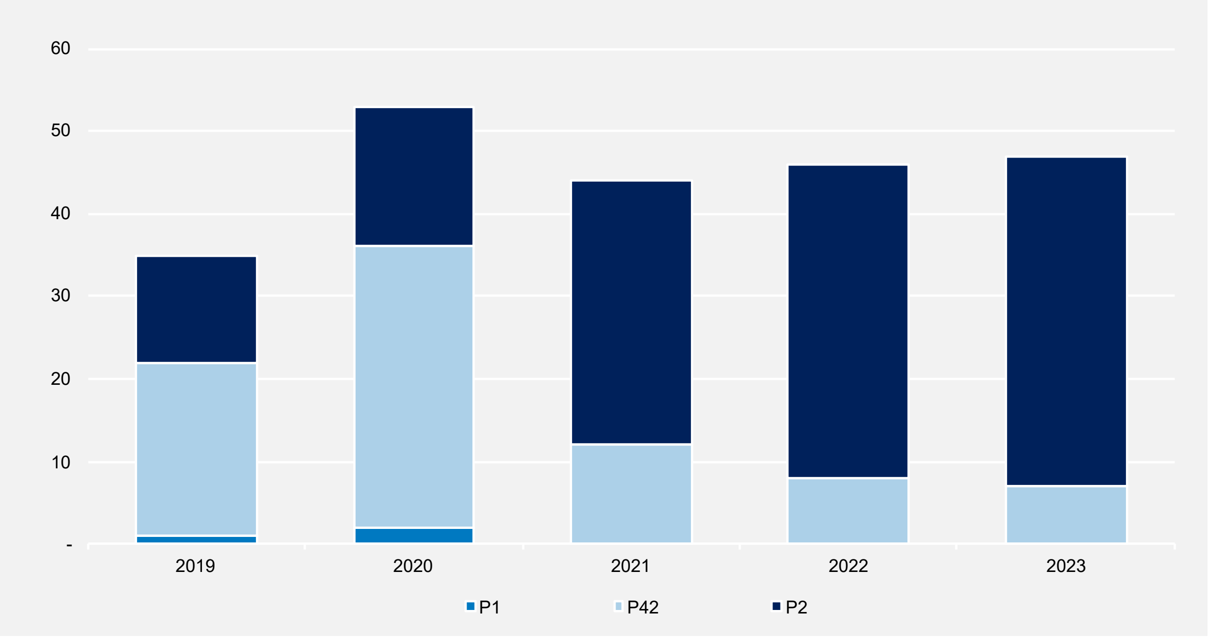
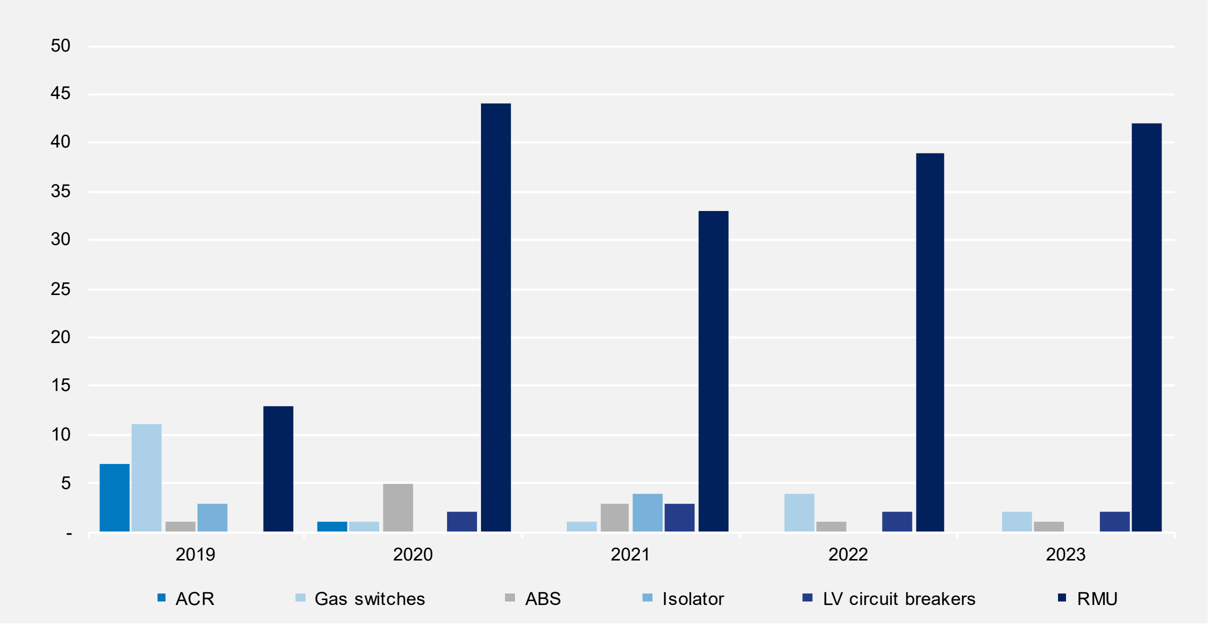


FIGURE 3 DISTRIBUTION SWITCHGEAR: DEFECTS BY TYPE



3.2 Inoperable switches

The safe operation of our distribution switchgear is a critical concern in the ongoing management of our distribution switchgear. For example, if our field crew operate switchgear with insufficient oil or gas insulation, it will result in catastrophic failure of the switchgear that can result in injury or death.

As a safety precaution, therefore, we may restrict the operation of specific distribution switchgear by assigning it ‘caution refer operations’ (CRO). This tag notifies operators that the switch is defective and may only be operated when it is de-energised and/or not opened at all.

While assigning CRO tags to distribution switchgear minimises the safety risk to our field crew, it increases network reliability risk as the next switch upstream will need to be operated, resulting in more customers off supply than would otherwise be the case.

The above experience has driven the commencement of two safety-driven programs within the current regulatory period.

HV ABS replacement program

In 2016, Powercor experienced increasing numbers of safety incidents where expulsion interrupters fitted to HV ABS failed when the switch was being opened (i.e. they did not perform the intended arc suppression function). This resulted in switch operators being showered with debris.

Subsequent defect analysis found high defect rates with each type of expulsion interrupter, but that no single external factor was responsible. It was also found that a condition inspection of in-service units would not provide a reliable assessment, and that after opening, the units cannot be economically repaired.

These assets were also found on the CitiPower networks and therefore resulted in the CRO-tagging of these switch types, and a replacement program was accepted by the AER in its 2021–26 final determination.

In 2022, the CRO-tagged HV ABS population increased to include more ABS manufacturers and types as more safety concerns came to light.

RMU replacement program

In 2022, we have identified some early RMUs that do not have a gauge to identify the oil volume or gas pressure in the devices. If an RMU has insufficient amount of oil or gas insulation, it is unsafe to operate as it could arc and cause mal-operation or an explosion, and result in injury to staff and loss of supply to customers.

All RMUs without gauges are now tagged CRO inoperable.

3.3 Demand growth

The electrification of everything from homes to transport, along with ongoing population growth, will require our energy system to evolve. By 2031, for example, we are forecasting a 26 per cent increase in annual consumption and 7 per cent growth in peak demand.

Growth in demand increases the energy that would not be supplied to customers if our distribution switchgear failed.

We forecast demand at an asset level. Our risk modelling uses these asset level demand forecasts to accurately evaluate the energy at risk of not being supplied to customers downstream of specific assets.

4. Forecast interventions

Our current asset management approach for distribution switchgear includes cyclic inspections and interventions, where required, to meet service levels consistent with our compliance obligations and stakeholder expectations.

Typically, replacement of distribution switchgear is the only credible response to major defects and failures (including CRO switchgear), as there is no viable repair option and additional inspection and maintenance will not address the underlying asset condition. For example:

- for pole-mounted switchgear, these cannot be repaired in-situ and removal and repair in the workshop would be more costly than replacement
- for non-pole switchgear, repairs can address minor defects (such as minor oil leaks by tightening seals or applying patching compounds), however, major defects and failures (such as major oil leaks or gas leaks) will require replacement.

The derivation of our forecast interventions for the 2026–31 regulatory period, for our high-volume assets such as distribution switchgear, are based on three broad categories—faults, corrective and risk-based forecasts. This approach is summarised in figure 4.

FIGURE 4 FORECAST CATEGORIES

Forecast interventions	=	Fault	+	Corrective	+	Risk-based
		Responses to asset failures that caused outages, including those due to external factors (such as third-party damage)		Interventions to address conditional failures associated with observable defects, deteriorated asset condition, and non-compliances		Proactive interventions based on cost-benefit analysis, where risk reduction benefits outweigh intervention costs

4.1 Forecast volumes

For the 2026–31 regulatory period, a summary of our forecast volumes for distribution switchgear is shown in table 4.

TABLE 4 DISTRIBUTION SWITCHGEAR: VOLUMES

VOLUMES	FY27	FY28	FY29	FY30	FY31	TOTAL
Defective switches	84	76	76	78	79	391
Defective fuses and surge diverters	45	44	44	44	44	221
Inoperable HV ABS program	28	28	28	28	28	140
Inoperable RMU program	27	27	27	27	27	135
Total	**184**	**175**	**175**	**177**	**178**	**887**

Note: Volumes associated with faults are consolidated with defective switches above

4.1.1 Fault replacements

Faults on our distribution switchgear assets occur somewhat randomly across our network, and accordingly, our fault-based distribution switchgear forecast is based on a simple average over the previous five-year period.

4.1.2 Corrective replacements

Our corrective forecasts for distribution switchgear replacements are based on historical annual asset defect rates and forecast asset population, consistent with independent statistical analysis on the best fit of our historical data. Specifically:

- the annual asset defect rate is the number of annual defects found per total asset population, and reflects the different cyclic inspection intervals for various switchgear types
- historical asset defect rates for each switchgear type were analysed independently, the historical average prediction model was found to best fit the underlying data (i.e. the historical asset defect rates yielded a very low root mean square error—ranging from 0 to 0.03—for all switchgear types, which demonstrates low error and hence more precise predictions.[4]
- forecast asset population is determined using linear regression based on our historical asset population growth for each switchgear type. Independent assessment of our historical asset population growth over time found they exhibited a linear trend, and a linear regression prediction model was found to be the best fit of our historical asset population (i.e. these yielded consistently high R-square values—ranging from 0.71 to 0.99—which demonstrates the linear regression model is a very good fit).[5]

For fuses and surge diverters, these are forecast based on historical averages given their high-volume and management approach of replacement-on-failure.

[4] PAL ATT 4.02 - Simon Holcombe (Melbourne University) - EDPR defect forecasting methodology - Aug2024 - Public, p. 14

[5] PAL ATT 4.02 - Simon Holcombe (Melbourne University) - EDPR defect forecasting methodology - Aug2024 - Public, p. 24

4.1.3 Risk-based replacements

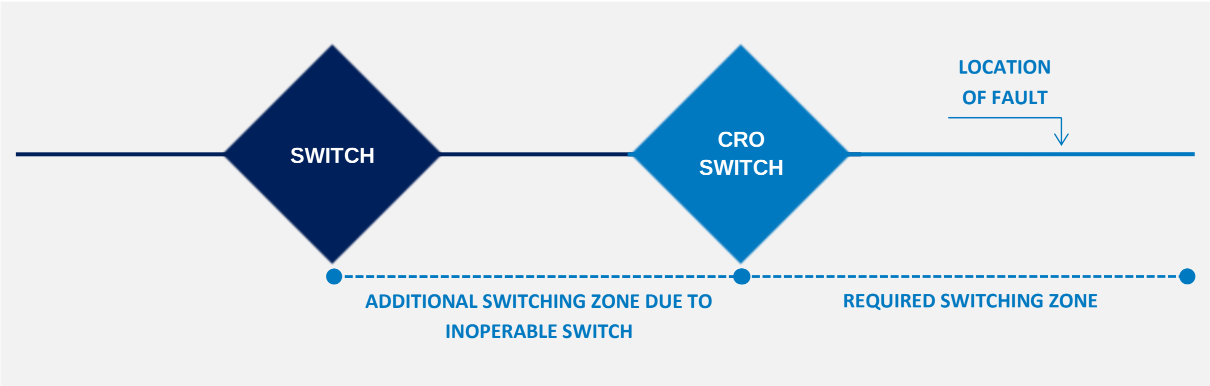
Our distribution switchgear intervention forecast includes two separate risk-based programs, with further detail on each set out in appendices A and B of this document. These programs include:

- risk-based replacement of inoperable HV air-break switches
- risk-based replacement of inoperable ring main units.

These risk-based programs are both based on a quantitative cost-benefit assessment of replacement costs compared with the incremental energy at risk due to the inability to operate CRO-tagged switchgear. As shown in figure 5, where the switch immediately upstream of the planned works (or outage) is deemed inoperable, a switch further upstream will need to be operated. This results in an additional switching zone of customers without supply.

The approach adopted for these business cases is broadly consistent with the methodology accepted by the AER in previous regulatory determinations for the establishment of our inoperable HV air-break switch program.[6]

FIGURE 5 ADDITIONAL SWITCHING ZONE INTERRUPTED DUE TO CRO SWITCHGEAR



4.1.4 Top-down portfolio review

As part of challenging our distribution switchgear intervention forecast, we considered the overall driver of our forecast interventions. As expected, the primary uplift relative to historical performance is the impact from our risk-based programs. These risk-based programs have targeted identified needs, and clear benefits cases.

Further, given our underlying defect volumes are based on historical performance, it is likely our forecasts will under-represent future defect volumes. In particular, we anticipate an increasing defect trend in RMUs following the commencement in 2024 of our online partial discharge monitoring program for indoor substations.

4.2 Expenditure forecast

To develop expenditure forecasts for our distribution switchgear asset class, we have multiplied the forecast intervention volumes by observed unit rates for different switchgear types.

Table 5 summarises this expenditure forecast for the 2026–31 regulatory period.

6 See, for example: AER, Powercor distribution determination 2021 to 2026, Attachment 5, p. 13

TABLE 5 DISTRIBUTION SWITCHGEAR: EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
Defective switches	6.9	6.0	5.9	6.1	6.1	31.0
Defective fuses and surge diverters	0.2	0.2	0.2	0.2	0.2	1.2
Inoperable HV ABS program	1.1	1.1	1.1	1.1	1.1	5.7
Inoperable RMU program	2.8	2.8	2.8	2.8	2.8	13.9
Total	**11.1**	**10.2**	**10.1**	**10.2**	**10.3**	**51.9**

Note: Expenditure presented above will not exactly match the Reset RIN due to the allocation of some works across multiple asset categories

A

INOPERABLE HV ABS PROGRAM

A Inoperable HV ABS program

As outlined in section 3.2, in 2016 our Powercor network experienced increasing numbers of safety incidents where expulsion interrupters fitted to HV ABS failed when the switch was being opened. The safety risks associated with these assets, and corresponding failure analysis, led to the CRO-tagging of these switch types.

The underlying and ongoing safety concerns associated with these assets have also been raised by the Electrical Trades Union and WorkSafe Victoria.

These assets were also found on our CitiPower network and therefore resulted in the CRO-tagging of these switch types.

In 2022, the CRO-tagged HV ABS population increased to include more ABS manufacturers and types as more safety concerns came to light. We now have 140 (or 8 per cent) of our HV ABS population tagged as CRO inoperable.

A.1 Identified need

While assigning CRO inoperable tags to HV ABS minimises the safety risk to our field crew, it increases network reliability risks for our customers. Network reliability risks are increased as the next switch upstream or downstream will need to be operated, resulting in more customers than necessary being off supply. The impact of this will increase over time with further electrification.

We have an obligation to maintain reliability and minimise safety risks as far as practicable. Hence, there is a need to address the safety and reliability risks posed by these CRO inoperable HV ABS.

A.2 Options considered

Table 6 lists all the potential credible options considered to maintain reliability and minimise safety risks associated with our inoperable HV ABS.

The repair of these switches has previously been demonstrated to be uneconomic, and so was not considered a feasible option. Similarly, increased inspection of in-service units would not address the underlying safety issue and the removal of these switches entirely would permanently reduce switching capability. Hence, neither were considered credible options that would meet the identified need.

TABLE 6 POTENTIAL CREDIBLE OPTIONS

OPTION	DESCRIPTION
1	**Do nothing different** Maintain the CRO inoperable status of these HV ABS; this would accept the safety and increasing reliability risks
2	**Replace all CRO inoperable HV ABS in one year** This option involves replacing all CRO inoperable HV ABS immediately with gas switches
3	**Replace all CRO inoperable HV ABS across five years** This option involves replacing all CRO inoperable HV ABS across five years with gas switches, implying an annual replacement rate of 28
4	**Replace all CRO inoperable HV ABS across 10 years** This option involves replacing all CRO inoperable HV ABS across 10 years with gas switches, implying an annual replacement rate of 14
5	**Replace all CRO inoperable HV ABS across 15 years** This option involves replacing all CRO inoperable HV ABS across 15 years with gas switches, implying an annual replacement rate of 9

To assess the options above, we applied the methodology outlined in section 4.1.3 and compared the net benefits of each option relative to the do-nothing base case (i.e. option one). This assessment is set out in our attached model.[7]

Specifically, our quantitative modelling compares the replacement cost with the incremental energy at risk of operating the next switch upstream of the CRO switch.[8] The incremental energy at risk is based on incremental additional customer numbers, customer type and the corresponding value of customer reliability (VCR), and the relevant demand forecast. This was used this to determine the volume and priority of replacement, as follows:

- where the value of energy at risk exceeded the annualised cost to replace the switches, the switches were prioritised for replacement from highest to lowest value of unserved energy
- where the value of energy at risk did not exceed the annualised cost to replace the switches, it is assumed switches will instead be replaced when they can be efficiently bundled with other work packages.

A summary of replacement volumes based on the above is set out in table 7.

7 CP MOD 4.16 - CRO inoperable HV air break switches - Jan2025 - Public
8 Where data was not available on individual switches, we applied population statistics to estimate the number of HV ABS that should be prioritised for replacement or bundled with other works.

TABLE 7 REPLACEMENT ASSESSMENT FOR INOPERABLE HV ABS

CRITERIA	VOLUME
Switches where energy at risk exceeded the annualised cost	105
Switches where energy at risk did not exceed the annualised cost	35
Total population of inoperable HV ABS	**140**

Table 8 shows the results of our option evaluation to determine the optimal replacement timeframe, relative to our base case.

TABLE 8 OPTION EVALUATION: RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COST	PV BENEFITS	NET BENEFITS
2	Replace all CRO inoperable HV ABS in one year	5.2	42.9	37.7
3	Replace all CRO inoperable HV ABS in five years	4.9	41.1	36.2
4	Replace all CRO inoperable HV ABS in 10 years	4.5	38.8	34.3
5	Replace all CRO inoperable HV ABS in 15 years	4.1	36.6	32.5

A.3 Preferred option

As shown above, option two—replacing all inoperable HV ABS' in one year—provides the greatest benefit to our customers. This is driven by the prioritised replacement of inoperable switches (noting the replacement of the remaining bundled switches did not have a material impact on the analysis).

Notwithstanding that option two results in the highest economic benefits, a slower replacement program is likely to be more prudent with respect to deliverability and minimising disruptions to customers from increased planned outages. Accordingly, our preferred option is to replace all CRO inoperable HV ABS across a five-year period (i.e. option three).

Under option three we will replace all CRO inoperable HV ABS in the 2026–31 regulatory period.

A summary of the proposed costs for the preferred option are set out in table 9.

TABLE 9 PREFERRED OPTION: EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
Inoperable HV ABS program	1.1	1.1	1.1	1.1	1.1	5.7

B

INOPERABLE RMU PROGRAM

B Inoperable RMU program

As outlined in section 3.2, in 2022 a subset of our RMU fleet were identified that do not have gas or oil gauges to identify the oil volume or gas pressure in the devices. If an RMU has insufficient amount of oil or gas insulation, it is unsafe to operate as it could arc and cause mal-operation or an explosion, and result in injury to staff and loss of supply to customers.

The underlying and ongoing safety concerns associated with these assets have also been raised by our operators, the Electrical Trades Union and WorkSafe Victoria. These safety risks have led to the CRO-tagging of these RMUs.

A summary of the CRO-tagged RMU population is provided in table 10.

TABLE 10 CRO-TAGGED RMU POPULATION

SWITCHGEAR TYPE	VOLUME
CRO-tagged RMU: gas	192
CRO-tagged RMU: oil	76
Total CRO-tagged	**268**

B.1 Identified need

While assigning CRO inoperable tags to RMUs without appropriate gauges minimises the safety risk to our field crew, it increases network reliability risks for our customers. Network reliability risks are increased as the next switch upstream or downstream will need to be operated, resulting in more customers than necessary being off supply. The impact of this will increase over time with further electrification.

We have an obligation to maintain reliability and minimise safety risks as far as practicable. Hence, there is a need to address the safety and reliability risks posed by these CRO inoperable HV ABS.

B.2 Options considered

Table 11 lists all the potential credible options considered to maintain reliability and minimise safety risks associated with our inoperable RMUs.

TABLE 11 POTENTIAL CREDIBLE OPTIONS

OPTION	DESCRIPTION
1	**Do nothing different** Maintain the CRO inoperable status of these RMUs; this would accept the safety and increasing reliability risks
2	**Replace all CRO inoperable RMUs in one year** This option involves replacing all CRO inoperable RMUs immediately with gas RMUs
3	**Replace all CRO inoperable RMUs across five years** This option involves replacing all CRO inoperable RMUs across five years with gas switches
4	**Replace all CRO inoperable RMUs across 10 years** This option involves replacing all CRO inoperable RMUs across 10 years with gas switches
5	**Replace all CRO inoperable RMUs across 15 years** This option involves replacing all CRO inoperable RMUs across 15 years with gas switches

We also explored non-replacement options to address the safety and reliability risk of these RMUs by retrofitting a gauge or installing remote switching capability. However, these were found not to be credible options:

- it is not technically feasible to retrofit a gauge on our existing gas RMUs due to their construction (e.g. the way gas RMUs are sealed after filling with SF6 does not allow for the retrofitting of a gas gauge)
- it is not economic to retrofit a gauge on our existing oil RMUs given the high retrofit cost and their underlying age; rather, it is more economic to replace these aged RMUs with new RMUs that have gauges
- the removal of these switches entirely was not considered as it would significantly change our network topology and permanently reduce switching capability.

To assess the credible options above, we applied the methodology outlined in section 4.1.3 and compared the net benefits of each option relative to the do-nothing base case (i.e. option one). This assessment is set out in our attached model.[9]

Specifically, our quantitative modelling compares the replacement cost with the incremental energy at risk of operating the next switch upstream of the inoperable RMU. It also modelled the energy at risk impacts of the planned outage to replace these RMUs, assuming a level of job bundling to minimise incremental costs and avoid the need for additional outages.

Table 12 shows the results of our option evaluation to determine the optimal replacement timeframe, relative to our base case.

[9] CP MOD 4.13 - RMUs - Jan2025 - Public

TABLE 12 OPTION EVALUATION: RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COST	PV BENEFITS	NET BENEFITS
2	Replace all CRO inoperable RMUs in one year	24.8	40.3	15.6
3	Replace all CRO inoperable RMUs in five years	22.9	36.6	13.6
4	Replace all CRO inoperable RMUs in 10 years	20.9	33.1	12.2
5	Replace all CRO inoperable RMUs in 15 years	19.2	30.6	11.4

B.3 Preferred option

As shown above, option two—replacing all inoperable RMUs in one year—provides the greatest benefit to our customers. This is driven by the immediate benefits from a prioritised replacement program.

Notwithstanding this, a slower replacement program is likely to be more prudent with respect to deliverability and minimising disruptions to customers from increased planned outages. Accordingly, our preferred option is to replace all CRO inoperable HV ABS across a 10-year period (i.e. option four).

Under option four we will replace a total of 135 of the existing inoperable RMUs in the 2026–31 regulatory period.

A summary of the proposed costs for the preferred option are set out in table 9.

TABLE 13 PREFERRED OPTION: EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
Inoperable RMU program	2.8	2.8	2.8	2.8	2.8	13.9

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