CITIPOWER

ASSET CLASS OVERVIEW

ZONE SUBSTATION SWITCHGEAR

CP BUS 4.09 – PUBLIC

2026–31 REGULATORY PROPOSAL

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1. Overview

The management of our zone substation switchgear is critical to our ability to maintain network reliability and minimise safety risk as far as practicable.

We manage these assets on a least lifecycle cost basis, underpinned by the continuous refinement of our risk analysis and understanding of the asset condition and performance. We adjust our asset replacement and maintenance timing as inputs to our risk evaluation change, such as asset cost, reliability and failure consequence.

Our zone substation switchgear forecast is consistent with this detailed risk-based approach. It enables the identification of the highest net benefit solution to manage the substation, based on the identified failure modes of our switchgear and the corresponding probabilities, likelihoods, and consequences of failures.

Our approach is also consistent with the AER's asset replacement planning application note, and modelling accepted by the AER in previous regulatory decisions.

In total, our zone substation switchgear forecast represents an increase in expenditure from the current 2021–26 regulatory period. This forecast comprises the replacement of several switchboards, with three of these representing in-flight projects that will commence this regulatory period.

Overall, our zone substation switchgear program results in a reduction in risk over the 2026–31 regulatory period. However, total zone substation level risks across our portfolio are increasing between FY27 and FY31, even after our proposed interventions (i.e. our combined zone substation works program, including switchgear, transformers and protection, will still not maintain overall zone substation reliability). In this context, our propose switchboard replacements are a key component of our long-term management plans for our zone substations, and are prudent to deliver in the 2026–31 regulatory period.

A summary of our forecast projects and corresponding capital expenditure is shown in table 1.

TABLE 1 ZONE SUBSTATION SWITCHGEAR EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
In-flight switchboard projects						
CW switchboard replacement (11kV)	2.2	-	-	-	-	**2.2**
LQ switchboard replacement (11kV)	8.5	4.3	-	-	-	**12.8**
B switchboard replacement (11kV)	2.4	9.9	5.3	-	-	**17.6**
Forecast switchboard projects						
R switchboard retirement (22kV)	2.6	-	-	-	-	**2.6**
AR switchboard replacement (11kV)	5.8	2.9	-	-	-	**8.7**
RD switchboard replacement (11kV)	-	5.4	2.7	-	-	**8.1**
NC switchboard replacement (11kV)	-	-	2.7	5.4	-	**8.1**
VM switchboard replacement (11kV)	-	-	5.1	5.1	5.1	**15.3**
Total	**21.6**	**22.4**	**15.8**	**10.5**	**5.1**	**75.4**

Note: Expenditure reported in this category in our Reset RIN is materially lower than this amount, as major plant replacement works (such as switchboard replacements) are allocated across multiple RIN categories to reflect the nature of the work undertaken.

2. Background

Zone substation circuit breakers are mechanical switching devices designed to protect electrical circuits and associated components from damage caused by an overload or a fault, whilst ensuring continued service to unaffected circuits. Zone substation circuit breakers can be standalone, mounted in a gas insulated switchgear pressure vessel or in an indoor switchboard.

Circuit breaker operation is generally initiated by a signal from the protection and control system and can be operated remotely. When a circuit breaker operates, it disconnects a circuit and causes an arc to form, which is quenched by the circuit breaker insulating medium. Circuit breaker insulating medium can be mineral oil, air, sulphur hexafluoride (SF6) or vacuum.

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

2.1 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

Our zone substation switchgear asset class comprises circuit breakers at multiple voltages and insulating mediums. As shown in table 2, most of our circuit breakers are 11kV oil-filled.

Further, our 6.6kV,11kV and 22kV circuit breakers are indoor switchboard types, reflecting the nature of the substations in inner-urban and CBD areas. Our 66kV circuit breakers are predominantly outdoor circuit breakers.

TABLE 2 ZONE SUBSTATION CIRCUIT BREAKER POPULATION

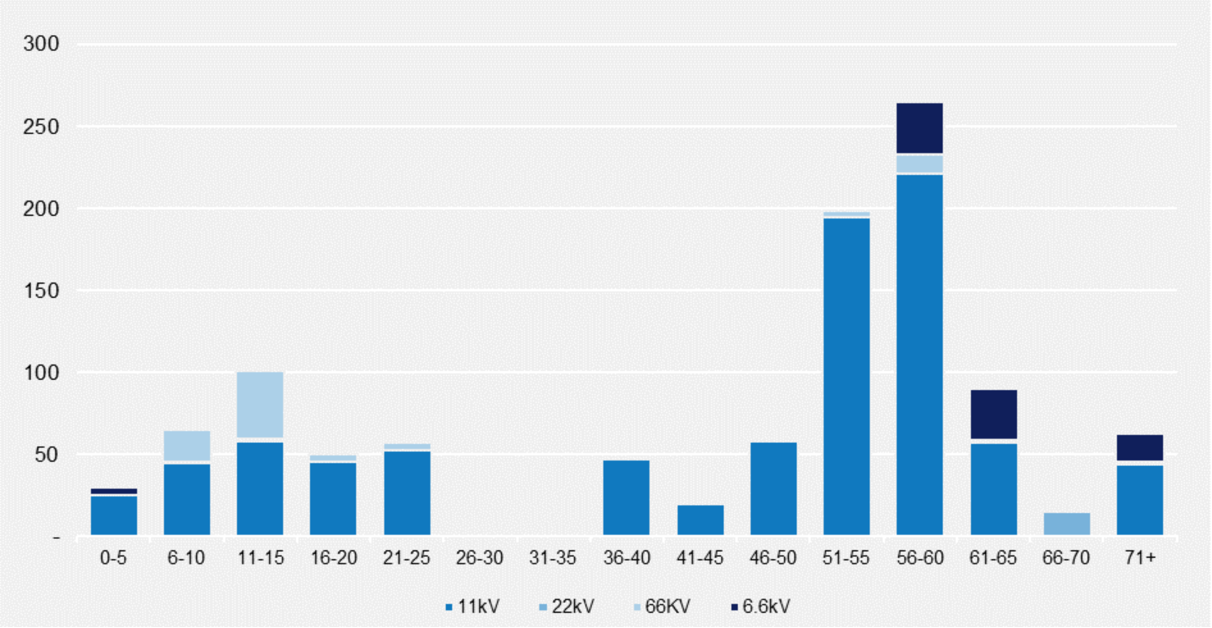
VOLTAGE TYPE	OIL	SF6	VACUUM	TOTAL
6.6kV	80	0	5	**85**
11kV	589	0	281	**870**
22kV	17	1	2	**20**
66kV	22	67	0	**89**
Total	**708**	**68**	**288**	**1,064**

2.3 Asset age profile

Our zone substation circuit breakers have an average life of 60 years. Average life refers to the average life span of circuit breaker, after which the asset is likely to be less reliable and require replacement. However, some circuit breaker require replacement before the average life due to type issues, environmental issues or deteriorated condition.

Figure 1 shows the age profile of our zone substation circuit breakers, with 169 having exceeded their average life today. Without intervention, this will increase to 663 circuit breakers by the end of the 2026–31 regulatory period.

FIGURE 1 NUMBER OF ZONE SUBSTATION CIRCUIT BREAKERS BY AGE (YEARS)



3. Identified need

The performance of our zone substation switchgear may impact our network service level, as failure may lead to a loss of supply for customers, pose safety risks to our personnel and the public and potentially catch on fire. This may also result in significant unplanned expenditure to restore supply to our customers.

The identified need, therefore, is to manage our zone substation 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 zone substation switchgear, which has informed how we assess (and respond, as required to) to this identified need.

3.1 Historical asset performance

We monitor the following two key indicators to inform our approach to meet the identified need:

- failures, which are functional failures that occur while the asset is in service
- high priority defects, which indicate deteriorating condition and are leading indicators of future failures.

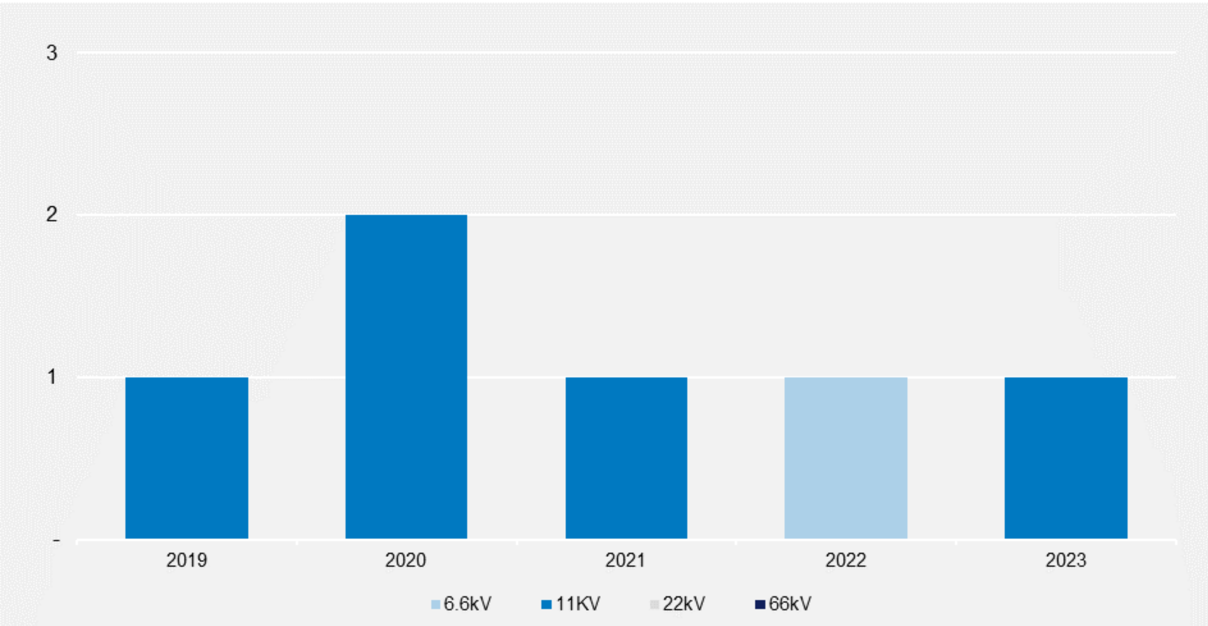
We use our historical asset performance, substation particulars and consequence information to inform and refine our risk evaluation for this asset class.

3.1.1 Historical asset failures

Zone substation switchgear are traditionally very reliable as evidenced by the low annual number of failures. However, we have experienced circuit breaker failures annually since 2019 as shown below in figure 2.

The potential consequences associated with zone substation circuit breaker failures can range from minor to catastrophic depending on zone substation and network configurations.

FIGURE 2 ZONE SUBSTATION CIRCUIT BREAKER FAILURES



3.1.2 Historical asset defects

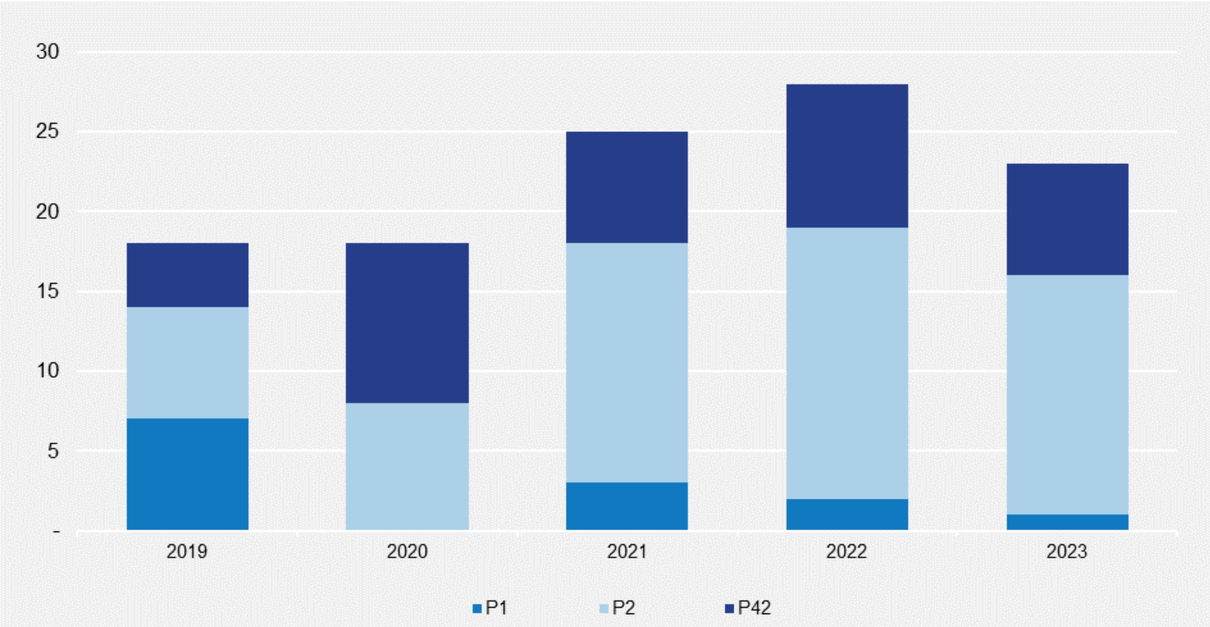
Defects are identified during cyclic asset inspections. Our response to identified defects depends on the nature and severity of the defect and may include more frequent re-inspections. High priority defects that result in intervention are shown in table 3.

TABLE 3 RESPONSE TIMEFRAME 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 figure 3, our high priority defects have been increasing from 2019, driven by increasing P2 defects. This is indicative of the deteriorating condition of our circuit breakers.

FIGURE 3 NUMBER OF HIGH PRIORITY DEFECTS



3.2 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 zone substation switchgear failed.

4. Forecast interventions

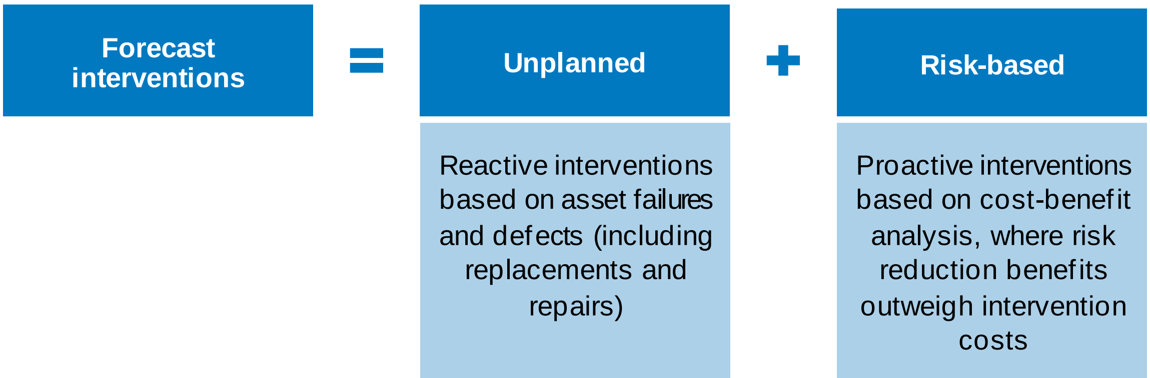
Our current asset management approach for our zone substation switchgear includes multiple options to meet our required service levels, consistent with our compliance obligations. Specifically, these options include the following:

- ongoing planned, preventative maintenance
- targeted replacement of specific components where technically feasible
- defer replacement of circuit breakers through online monitoring systems or other mitigation controls, including asset refurbishment
- asset replacement based on condition and risk assessments, including the impact of common-cause failures.

We constantly revise our plans based on the latest information regarding cost, reliability and risk of these assets to ensure that we are meeting our obligations. As these inputs and understandings change, our forecast will fluctuate accordingly. Our forecast is based on the two categories, as shown in figure 4.

- unplanned interventions are responses to asset failures and defects, which include replacements and repairs. These repairs are considered capital expenditure as they extend the life of the asset
- risk-based interventions are determined by a cost benefit analysis, where risk reduction benefits outweigh the intervention costs.

FIGURE 4 FORECAST CATEGORIES



4.1 Unplanned interventions

We forecast our unplanned interventions based on historical average of the previous five years. These typically comprise minor station works of low materiality.

4.2 Risk-based interventions

Our risk-based interventions comprise our typical risk-based switchgear replacements. This section explains our assessment methodology, with site specific assessments set out in appendix A.

These forecasts are developed based on sophisticated risk modelling, consistent with the AER's asset replacement planning note and modelling that was accepted by the AER in previous regulatory decisions.[1] This modelling is attached with our regulatory proposal and supported by our asset risk quantification guide.[2]

4.2.1 Forecast methodology

Our risk evaluation method assesses risk at the zone substation level instead of the individual circuit breaker. Assessing risks at zone substation level recognises the unique characteristic of circuit breakers and their impact on the network and customers. It considers the following:

- probability of circuit breaker failure
- joint and conditional probability based on similarity of circuit breaker at the zone substation
- available redundancy and load transfer capability at the zone substation
- zone substation load forecast, including the energy facilitated by the network
- number of transformers offline in the event of a circuit breaker failure
- length of the outage caused by the circuit breaker failure
- increased station risk until circuit breaker is replaced or repaired.

Our risk assessment is underpinned by a risk monetisation approach summarised in figure 5. This approach ensures we invest only when the cost of replacing existing infrastructure exceeds the total value of the underlying risks.

FIGURE 5 RISK MONETISATION APPROACH

Probability of failure

Several factors contribute to the deterioration and subsequent failure of circuit breakers. In the first instance, we have used our historical asset failure data to determine the probability of failure. Where required, this data is supplemented by failure type ratios from relevant industry surveys (e.g. such as those published by Ofgem).

Consequence of failure

Our approach to monetising risk compares the total cost (including risk) of technically feasible options. The preferred option(s) is that which provides the maximum benefit compared to costs.

Figure 6 shows an overview of how we determine the total cost of each option. It identifies the most beneficial solution to manage the substation, based on the identified failure modes for an asset, and the corresponding probabilities, likelihoods and consequences of failures.

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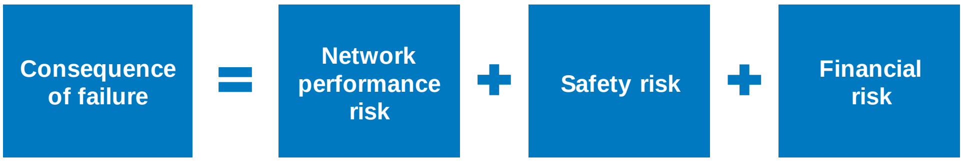
1 See, for example, the AER's final decision for our United Energy network; AER, United Energy distribution determination 2021 to 2026, Attachment 5, April 2021. This modelling approach has since been incorporated to support the asset management of our zone substation program across our three networks, including CitiPower.

2 CP MOD 4.10 - Parallel risk model - Jan2025 - Public; and CP ATT 4.01 – Asset risk quantification guide – Jan2025 – Public.

FIGURE 6 CONSEQUENCE OF FAILURE



The determination of these consequences is summarised below:

- network performance risk (energy at risk) – we quantify circuit breaker failure risk based on the overall risk at the zone substation. That is, we use a joint and conditional probability model to calculate the energy at risk cost for the substation. This considers available redundancy, load transfer capability at the substation, response times for different investments and the cost of multiple interventions that affect overall system reliability, rather than focusing on the condition of a singular asset. This is particularly important in zone substations as they are redundant systems, and the consequence of failure can vary throughout the year. The value of energy at risk is based on the AER's determined value of customer reliability, with a multiplier applied to this value for CBD zone substations to account for the criticality of load supplied by these stations[3]
- safety risks to our staff are determined based on the likelihood of a person present when the failure occurs, and the likelihood of an injury or death as a result. Our safety risks also consider the outcome of our switchboard arch flash assessment and the subsequent short and medium term controls in response (e.g. in 2022, Energy Safe Victoria (ESV) updated the Code of Practice on electrical safety for work on or near high voltage electrical apparatus, to include specific requirements for the risk of arc flash to be managed as far as reasonably practicable. ESV and Worksafe published their expectations on carrying out an arc flash / fault study or assessment, to IEEE 1584 or similar, and conducting a risk assessment, considering workers interacting with switchgear). The value of safety risks are based on the value of a statistical life from the Australian Government and injury values informed by Safe Work Australia
- financial risks comprise unplanned replacement and unplanned repair impacts respectively. For the purpose of monetising the risk of circuit breaker failures, we categorise these failures as either significant or major (or both, with a likelihood ratio assigned based on experience). Significant failures are those that are repairable, whereas major failures require the replacement of the asset. The corresponding costs are based on observed history.

With respect to financial risks, we note that zone substation assets are subject to a high level of management oversight, which results in low failure rates. However, as condition monitoring technology and asset understanding improves over time the occurrence of clear wear-out characteristics do not always materialise. This is particularly pertinent to complex, maintainable systems like power transformers and circuit breakers (whereas simpler assets do more typically demonstrate a defined end-of-life). As a result, the focus of our risk analysis tends to be on the consequence associated with failure, not just the condition. In addition, where the likelihood of failure due to condition tends to drop as a result of management or prevention of failures due to management techniques, the proportion of other failure causes increases and becomes the higher risk that needs to be managed.

The above is particularly important for older, obsolete assets that do not align with modern equipment specifications and can include maintenance-related failures due to lack of parts or skillsets to maintain, as well as systemic underlying failures (referred to as common-cause failures). We have experienced issues that are common to multiple assets at the same time, including the following:

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[3] For the 2026–31 regulatory period, this multiplier applies to our VM zone substation only. This is discussed in further detail in appendix A.

- concurrent 11kV current transformer faults in the switchboard at our MP zone substation
- concurrent offload voltage selector switch failures at our C zone substation (due to reaching end life)
- high duty feeder circuit breakers, such as regularly switched capacitor bank circuit breakers, experiencing metal fatigue cracking around the solenoid gland plates.

These occurrences demonstrate that this kind of risk is real and needs to be considered alongside other risk factors, such as condition, in a comprehensive risk analysis. These are all included in our analysis.

4.2.2 Options considered

Table 4 lists all the potential credible zone substation circuit breakers intervention options. The suitability of these options, however, depends on the zone substation.

TABLE 4 RISK-BASED INTERVENTION OPTIONS

OPTION	DESCRIPTION
Do-nothing different	No change to existing practices and no planned replacement
Online monitoring	Install online monitoring on the circuit breaker or switchboard
Revised maintenance program	This option updates our maintenance practice and timing on each circuit breaker or switchboard bus
Simultaneous replacement of circuit breakers or switchboard and relays	Replace the circuit breakers or entire switchboard and relays simultaneously
Separate replacement of circuit breakers or switchboard and relays	Replace the relays first (because new circuit breakers can only interface with modern digital relays), followed by the replacement of the circuit breakers or switchboard (noting this will entail some re-work on the relays)

We also considered the following intervention options, but these have been assessed as not credible and thus not subject to economic assessment:

- replacement of only one bus of an aged switchboard – this will not reduce the probability of failure on the remaining buses and associated circuit breakers, and raises physical and integration challenges with different switchgear technologies
- refurbishment of the switchboard – this is not technically practicable and in any event, would provide immaterial benefits
- non-network solutions – we are not aware of non-network solutions that will be able to replace the functionality of a zone substation circuit breaker. Our zone substation circuit breaker replacements are listed in our annual distribution asset planning report (DAPR) and to date, we have not received any non-network proposals for circuit breaker asset replacement.

4.2.3 Forecast risk-based interventions

Based on the risk monetisation approach summarised above, we assessed individual zone substations for potential interventions in the 2026–31 regulatory period. These sites were then reviewed against our broader station works portfolio to identify overlaps and synergies.

This further reviewed identified the following:

- synergies were identified with our protection relay replacements, whereby it is efficient to deliver both circuit breaker and relay replacements simultaneously. These synergies were identified for each zone substation switchboard, and as such, these relay replacements have been removed from our protection forecasts
- adjustments to project timing were made to align with other proposed works at the station to ensure efficient and practical sequencing of projects.

We also recognise that the proposed works program to manage the risk associated with our ageing switchgear is a step-up compared with the 2021–26 regulatory period. We are confident in the deliverability of these projects, however, given the staggered timing of works (including in-flight projects) and the ability to leverage both our internal and external labour force.

A summary of our proposed zone substation circuit breaker replacements is set out in table 5. Further site-specific assessments are provided in appendix A.

TABLE 5 ZONE SUBSTATION SWITCHGEAR: FORECAST EXPENDITURE ($M, 2026)

EXPENDITURE	FY27	FY28	FY29	FY30	FY31	TOTAL
In-flight switchboard projects						
CW switchboard replacement (11kV)	2.2	-	-	-	-	**2.2**
LQ switchboard replacement (11kV)	8.5	4.3	-	-	-	**12.8**
B switchboard replacement (11kV)	2.4	9.9	5.3	-	-	**17.6**
Forecast switchboard projects						
R switchboard retirement (22kV)	2.6	-	-	-	-	**2.6**
AR switchboard replacement (11kV)	5.8	2.9	-	-	-	**8.7**
RD switchboard replacement (11kV)	-	5.4	2.7	-	-	**8.1**
NC switchboard replacement (11kV)	-	-	2.7	5.4	-	**8.1**
WA switchboard replacement (11kV)	-	-	5.1	5.1	5.1	**15.3**
Total	**21.6**	**22.4**	**15.8**	**10.5**	**5.1**	**75.4**

Note: Corresponding circuit breaker volumes are reported in our Reset RIN on an as-commissioned basis (i.e. in the last year of expenditure).

Top-down portfolio review

In addition to the review of overlaps and synergies identified above, we also assessed the change in zone substation circuit breaker risks, and that at the zone substation overall (i.e. the sum of circuit breaker, transformer and protection risks).

A central theme of our stakeholder engagement program was reliability, with customers consistently highlighting the importance of a maintaining a reliable energy supply. This view was explored in the context of our customers' increasing dependence on electricity given forecast electrification. Our replacement program and asset management practices are critical to ensure reliability outcomes for customers as well as maintaining trust throughout the energy transition for our customers to electrify.

As shown in figure 7, overall, our zone substation switchgear risks are expected to reduce by FY31 with and without our proposed interventions. This reflects the impact of in-flight projects.

However, as shown in figure 8, total zone substation level risks will still increase between FY27 and FY31, even after our proposed interventions (i.e. our combined zone substation works program will still not maintain overall zone substation reliability). Collectively, we consider our switchboard replacements are a key component of our long-term management plans for our zone substations, and are prudent to deliver in the 2026–31 regulatory period.

FIGURE 7 ZONE SUBSTATION RISK: SWITCHGEAR ($M, 2026)

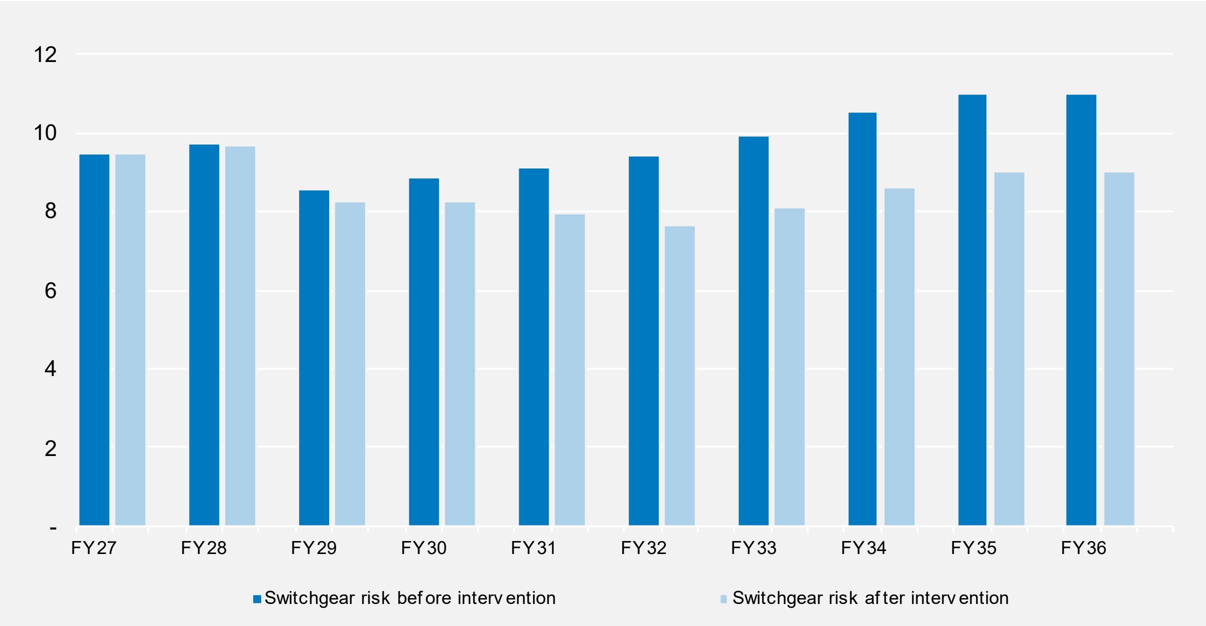
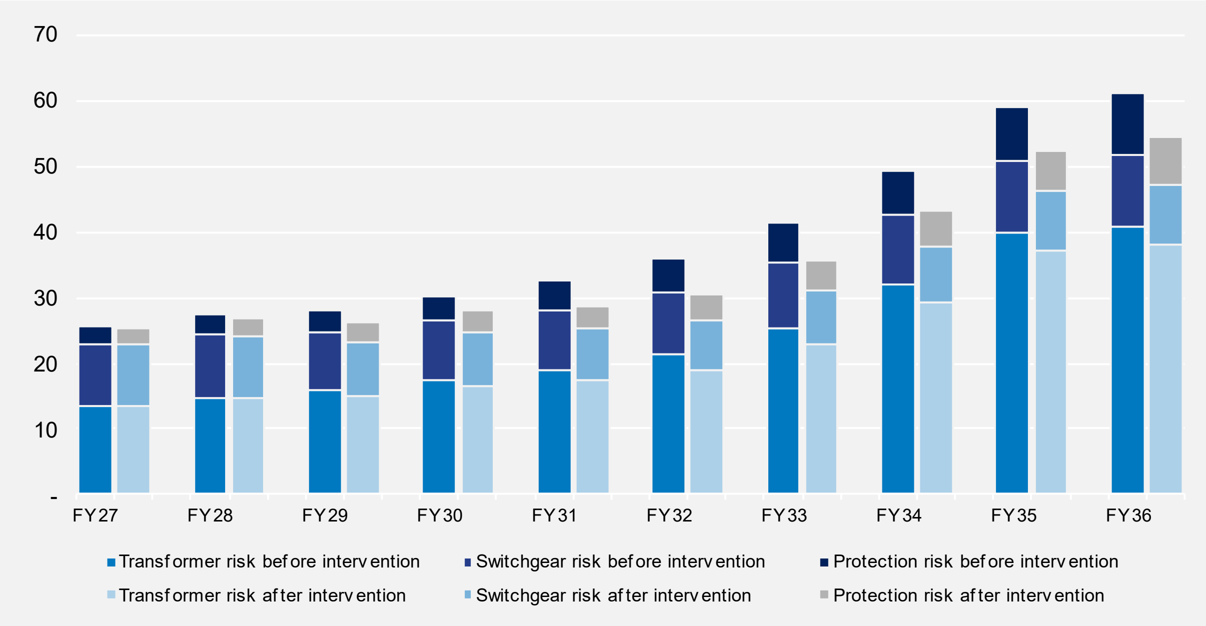


FIGURE 8 ZONE SUBSTATION RISK: COMBINED STATION ASSETS ($M, 2026)



A Switchgear replacements: site-based assessments

This appendix provides a summary of site-based assessments for our proposed risk-based zone substation switchgear replacements.

For each site, a full cost benefit analysis has been undertaken and is provided in the attached models. The options considered are consistent with those outlined in the body of this asset class overview and are presented relative to the base case (i.e. a do-nothing different option).

A.1 In-flight projects

As outlined above, we have three in-flight projects that will have costs delivered in the 2026–31 regulatory period. These are switchboard replacements at our LQ, CW and B zone substations.

We have completed the RIT-D process for our LQ zone substation, with the final project assessment report published and works underway. The commencement of works at LQ were intended to have started earlier in the 2021–26 regulatory period, however, temporary delays occurred due to the construction of the Hilton Hotel opposite the substation which required rebuilding of the LQ 11kV cable tunnels outside the substation (now complete).

Funding for this project was partially included in the AER's final determination for the 2021–26 regulatory period, recognising project scheduling was forecast to span multiple regulatory periods.

Our B zone substation was also included in the AER's final determination for the 2021–26 regulatory period. However, following supply chain and other cost increases during the period, revised costs to deliver the B switchboard replacement increased significantly.

Given these higher forecast costs, we are instead replacing the 11kV switchboard at CW (which supplies the adjacent distribution network area to the north-west of B).[4] This project is driven by network conversion needs, but is also expected to allow for replacement of the B switchboard in a more efficient manner. The RIT-D for the CW switchboard replacement is expected to be published in February 2025, and a RIT-D for the B switchboard in late 2025.

Pending the outcome of the RIT-Ds, both projects will commence construction in the 2021–26 regulatory period.

A.2 VM zone substation

Victoria Market (VM) zone substation is located in the north-west corner of Melbourne's CBD. The site houses an 11kV 3-bus double busbar switchboard, supplying a total of more than 9,600 customers across 30 distribution feeders.

A.2.1 Identified need

The VM 11kV switchboard is a mix of Brush VSI and Brush VTD busses and was constructed in 1967 comprising 39 switchgear panels. It is operating past its design life of 50 years. The switchgear was constructed in the UK, and recent communication with Brush indicated that spare parts are no longer available for this asset, it is no longer supported and decommissioning should be considered.

4 Noting this project was not included in the AER's final determination for the 2021–26 regulatory period.

In March 2007, resulting from an internal flashover and substantial fire in the number one transformer circuit breaker position on the B bus section, the rear busbar was damaged beyond economical repair and is permanently out of service. Damage to the front busbar and a number of circuit breaker positions were permanently repaired at the time using all available remaining spare parts for this switchboard.

In 2019, two switchboard panels (VM013 and VM021) were rendered permanently out of service due to unrepairable age related deterioration damage to the cable box bushings. This damage was identified as part of cable replacement works and resulted in two distribution feeders needing to be supplied by alternate sources at higher cost. Due to the age risk and no available spare parts (second hand or new), any further feeder panels that require cable work are expected to find the same deteriorated bushing condition, resulting in more permanently out of service feeder positions.

The risk of concurrent or widespread issues in this switchboard is sufficiently high, such that if an event occurred, we would likely be in breach of our CBD security of supply obligations under the Electricity Distribution Code of Practice (EDCoP).

The VM switchboard is also one of four switchboards which have operating restrictions imposed.

A.2.2 Option analysis

The existing VM switchboard currently has an online monitoring system installed. Hence, our base case considers the continued usage of online monitoring. In addition, both the simultaneous and separate replacement of the switchboard and relays have been assessed.

Given the switchboard age, improved or increased maintenance was not considered a credible option.

The results of our analysis, relative to a do-nothing base case, are shown in table 6.

TABLE 6 OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: maintain online monitoring with no further investment	-	-	-
2	Simultaneous replacement of circuit breakers or switchboard and relays	(9.1)	21.8	12.7
3	Separate replacement of circuit breakers or switchboard and relays	(8.89)	18.9	10.2

Preferred option

The preferred option is to simultaneously replace the switchboard and relays (option two) as this is the most economic option under the central scenario.[5] Replacing the existing switchboard will reduce failure risks, and hence, contribute to minimising the increase in overall zone substation risks across the forecast period.

Our VM zone substation serves as a transfer point for the LQ zone substation, which is currently having its switchboard replaced (due for completion in 2028). While our preference is to replace the existing VM switchboard earlier due to the constraints to the CBD with the introduction of restricted operation at VM, site construction works will not be practicable until the switchboard replacement at

5 CP MOD 4.10 - Parallel risk model - Jan2025 - Public; and CP MOD 4.05 - VM switchboard and relay - Jan2025 – Public.

LQ is completed. Hence, we have delayed the commencement of VM switchboard replacement to FY29, after the completion of LQ switchboard replacement.

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

A.3 AR zone substation

Armadale (AR) zone substation is located beside Armadale railway station and supplies more than 13,000 customers across 11 distribution feeders. It shares common boundaries with commercial and retail business as well as a carpark.

A.3.1 Identified need

AR zone substation has a two bus 11kV switchboard with 19 panels housing J18 oil-filled circuit breakers. These assets were commissioned in 1963 and are past their service life at 61 years old. The switchboard is of the bulk oil non-arc fault contained design.

There are limited HV transfers to other adjacent zone substations, such as nearby Balaclava and Toorak due to high load in the region. A fault in the switchboard, therefore, would result in considerable load at risk with repair times likely to be extensive due to very limited spare parts and new parts unavailable.

There is an online partial discharge monitoring system installed managing the risk of increasing discharge activity located within the switchboard, most of which had been narrowed down to the compound insulated sections and power transformer to voltage transformer connections.

The secondary systems protecting this switchboard vary in age due to different upgrade projects over time. However, most of the secondary wiring is original and starting to present reliability issues with failing insulation resulting in mal-operations.

The identified need is to address risks associated with failure to supply the area from the substation.

A.3.2 Option analysis

The existing AR switchboard currently has an online monitoring system installed. Hence, our base case considers the continued usage of online monitoring. In addition, both the simultaneous and separate replacement of the switchboard and relays have been assessed.

Given the switchboard age, improved or increased maintenance was not considered a credible option.

The results of our analysis, relative to a do-nothing base case, are shown in table 7.

TABLE 7 OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: maintain online monitoring with no further investment	-	-	-
2	Simultaneous replacement of circuit breakers or switchboard and relays	(6.2)	8.4	2.3
3	Separate replacement of circuit breakers or switchboard and relays	(5.9)	7.2	1.4

Preferred option

The preferred option is to simultaneously replace the switchboard and relays (option two) as this is the most economic option under the central scenario.[6] Replacing the existing switchboard will reduce failure risks, and hence, contribute to minimising the increase in overall zone substation risks across the forecast period.

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

A.4 RD zone substation

Riversdale (RD) zone substation is located beside the Lynden aged care facility and shares common boundaries with several residential properties and the Lynden Park sports fields. RD zone substation supplies more than 11,500 customers across 10 distribution feeders.

A.4.1 Identified need

RD zone substation has a two bus 11kV switchboard with 15 panels housing J18 and J22 oil-filled circuit breakers. These assets were commissioned in 1968 and at 56 years old are fast approaching the end of their service life. The switchboard is of the bulk oil non-arc fault contained design.

While there are adjacent HV feeders suitable for load transfers, the broader supply area is heavily loaded making bulk transfers away from RD difficult. A fault in the switchboard would, therefore, result in considerable load at risk with repair times likely to be extensive due to very limited spare parts and new parts unavailable.

Routine switchboard maintenance and testing activities have identified the solid insulation to be ageing at a faster rate than the average for this family of switchgear. The condition readings are approaching the limits at which removal from service or refurbishment would be required to maintain operability. Historically, refurbishment of switchboard components for this family of switchgear has been unsuccessful and typically lasts only less than a year before returning to pre-refurbishment condition (and in a few isolated cases, refurbished components electrically failing while in service).

There is an online partial discharge monitoring system installed to manage the risk of increasing discharge activity located within the switchboard. Recent maintenance activities and projects have conducted several handheld scans all of which indicated varying levels of partial discharge, with multiple locations causing concern, mainly in the compound insulated cable connections and in the bus tie circuit breaker. These partial discharge detections have driven the need for a permanent online

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[6] CP MOD 4.10 - Parallel risk model - Jan2025 - Public; and CP MOD 4.06 - AR switchboard and relay - Jan2025 – Public.

partial discharge monitoring system to be installed to provide online monitoring and trending to further define the risk to personnel and assets.

The identified need is to address risks associated with failure to supply the area from the substation.

A.4.2 Option analysis

The existing RD switchboard currently has an online monitoring system installed. Hence, our base case considers the continued usage of online monitoring. In addition, both the simultaneous and separate replacement of the switchboard and relays have been assessed.

Given the switchboard age, improved or increased maintenance was not considered a credible option.

The results of our analysis, relative to a do-nothing base case, are shown in table 8.

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

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: maintain online monitoring with no further investment	-	-	-
2	Simultaneous replacement of circuit breakers or switchboard and relays	(4.9)	5.9	1.0
3	Separate replacement of circuit breakers or switchboard and relays	(4.7)	4.8	(0.0)

Preferred option

The preferred option is to simultaneously replace the switchboard and relays (option two) as this is the most economic option under the central scenario.[7] Replacing the existing switchboard will reduce failure risks, and hence, contribute to minimising the increase in overall zone substation risks across the forecast period.

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

A.5 NC zone substation

Northcote (NC) zone substation is located beside the Santa Maria College and residential properties. It supplies more than 19,000 customers across 10 distribution feeders.

A.5.1 Identified need

NC zone substation has a two bus 11kV switchboard with 15 panels housing J18 and J22 oil-filled circuit breakers. These assets were commissioned in 1967 and at 57 years old are fast approaching the end of their service life. The switchboard is of the bulk oil non-arc fault contained design.

As NC zone substation is located on the edge of the CitiPower network and is surrounded by 6.6kV network, there are limited HV transfers to other adjacent zone substations. A fault in the switchboard, therefore, would result in considerable load at risk with repair times likely to be extensive due to very limited spare parts and new parts unavailable.

7 CP MOD 4.10 - Parallel risk model - Jan2025 - Public; and CP MOD 4.08 - RD switchboard and relay - Jan2025 - Public

There is no online partial discharge monitoring system installed to manage the risk of increasing discharge activity located within the switchboard. Recent maintenance activities and projects have conducted several handheld scans all of which indicate varying levels of partial discharge, with one location causing concern in the compound insulated transformer cable connection to the circuit breaker. This is currently being assessed for online monitoring to provide partial discharge trending to further define the risk to personnel and assets.

Recently the adjacent Santi Maria College expanded their buildings with the west boundary of our substation yard closest to our 11kV switch room now having classrooms and break out areas located nearby. While the separation of our building wall to the school building wall is approximately 20 metres, making it unlikely any flashover event within our switch room would impact the school building, the noise generated by such an event would be damaging.

The identified need is to address risks associated with failure to supply the area from the substation.

A.5.2 Option analysis

Our options analysis considers a base case with no additional investment, and assesses this relative to both the simultaneous and separate replacement of the switchboard and relays.

Given the switchboard age, improved or increased maintenance was not considered a credible option.

The results of our analysis, relative to a do-nothing base case, are shown in table 9.

TABLE 9 OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: maintain online monitoring with no further investment	-	-	-
2	Simultaneous replacement of circuit breakers or switchboard and relays	(5.2)	8.3	3.1
3	Separate replacement of circuit breakers or switchboard and relays	(5.2)	5.8	0.6

Preferred option

The preferred option is to simultaneously replace the switchboard and relays (option two) as this is the most economic option under the central scenario.[8] Replacing the existing switchboard will reduce failure risks, and hence, contribute to minimising the increase in overall zone substation risks across the forecast period.

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

A.6 R zone substation

Richmond (R) zone substation is adjacent to the former Richmond power station. The zone substation supplies both 11kV and 22kV feeders with over 6,300 customers across nine 11kV feeders and the Cremorne Railway main substation across two 22kV feeders.

8 CP MOD 4.10 - Parallel risk model - Jan2025 - Public; and CP MOD 4.08 - RD switchboard and relay - Jan2025 - Public

A.6.1 Identified need

The R zone substation 11kV switchboard was replaced in 2009 and is performing well. It is of the vacuum interrupter and arc fault contained design with all new protection installed at the time. As such the 11kV switchboard and its associated relays secondary wiring and DC systems do not need to be upgraded or replaced.

By contrast the 22kV switchboard installed in the late 1940s to be the interface between the Richmond power station generation supplies, Richmond zone substation and the Richmond terminal station is still in service and is well past its service life.

The 22kV switchboard is of the non-arc fault contained bulk oil design and is metal clad with cast iron body and compound insulation. There are no available spare parts for this switchgear and due to the construction of this switchboard any internal fault will be catastrophic destroying a significant portion of the switchboard up to a total loss and causing significant collateral damage to the switch room building. Due to their age, the 22kV circuit breakers have a large volume of oil in each (e.g. typically more than double that found in more modern bulk oil circuit breakers from the 1960s onwards), which also substantially increases both the risk of fire and the available fuel to sustain a fire associated with a fault in the 22kV switchboard.

There is no online partial discharge monitoring system installed to manage the risk of increasing discharge activity located within the switchboard. Maintenance partial discharge scans have detected varying levels of partial discharge within the solid insulation.

All secondary systems, relays and associated wiring throughout the 22kV switchboard and substation control room are original, including the line protection back to the Richmond terminal station and line protection between the railways substation. While a few relays have been upgraded these are still connected to the old 240V DC system, which is also at end of life and has progressively become more unreliable. The installed secondary wiring is original and is starting to mal-operate and become a reliability issue due to failure of aged and deteriorated insulation.

A current redevelopment of the former Richmond power station to a new entertainment precinct will increase the amount and frequency of people moving around the areas directly beside the 22kV switch room building.

To mitigate the risk to personnel and operational staff, operation of the 22kV switchboard is heavily restricted with all operations requiring an operator to be in the room for racking, spring charging or operating the circuit breaker with the bus and all feeders de-energised. All switching is to be done remotely, which increases the reliance on the aged DC systems and wiring.

Any failure of the 22kV switchboard will interrupt all supplies to substation R customers and Cremorne traction substation which is responsible for the majority of all signalling and telemetry for eastern and south-eastern rail lines out of Melbourne CBD.

The identified need is to address risks associated with failure to supply the area from the substation.

A.6.2 Option analysis

Our options analysis considers a base case with no additional investment and assesses this relative to the following two separate retirement options:

- retire the 22kV switchboard and install three RMUs to supply three existing transformers and two Cremorne 22kV feeders
- retire the 22kV switchboard and directly connect the three existing transformers to the three existing 22kV feeders and the two Cremorne 22kV feeders are to be supplied directly from Richmond terminal station.

Given the switchboard age, improved or increased maintenance or online monitoring were not considered credible options.

The results of our analysis, relative to a do-nothing base case, are shown in table 10.

TABLE 10 OPTIONS EVALUATION RELATIVE TO BASE CASE ($M, 2026)

OPTION		PV COSTS	PV BENEFITS	NET BENEFITS
1	Base case: maintain online monitoring with no further investment	-	-	-
2	Retirement of switchboard and installation of three RMUs	(1.9)	2.6	0.7
3	Retirement of switchboard with alternative feeder connections	(3.1)	2.7	(0.4)

Preferred option

The preferred option is the retirement of the 22kV switchboard and installation of three RMUs (option two) as this is the most economic option under the central scenario.[9] Retiring the existing switchboard will reduce failure risks, and hence, contribute to minimising the increase in overall zone substation risks across the forecast period.

Sensitivity analysis was also used to test the robustness of the central scenario result to potential variations in costs and benefits. The preferred option remained economic under all scenarios.

[9] CP MOD 4.10 - Parallel risk model - Jan2025 - Public; and CP MOD 4.09 - HV switchboard and relay retirement R 22kV - Jan2025 - Public

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