AUGMENTATION

BUSHFIRE MITIGATION FORECAST OVERVIEW

PAL BUS 3.11 – PUBLIC
2026–31 REGULATORY PROPOSAL

Table of contents

1. Overview 2

2. Background 4

2.1 Bushfire and safety obligations 4

3. Our bushfire mitigation journey 6

4. Bushfire risk assessment 7

4.1 Present risk exposure 7

4.2 Risk causes 9

4.3 Control option identification 10

4.4 Control option effectiveness 11

4.5 Estimate control cost 12

4.6 AFAP analysis 12

4.7 AFAP recommendations 13

A Maintaining REFCL compliance 15

B Maintaining REFCL reliability 49

C Minimising bushfire risks in the Horsham supply area 53

D Minimising bushfire risks from bare 22kV conductors 57

E Minimising bushfire risks from SWER lines 61

F Minimising bushfire risks from HV wood crossarms 66

1. Overview

Victoria is one of the most bushfire prone areas in the world, with the devastating impacts on communities evidenced by the recent 2024 and 2025 bushfires in north-western Victoria and the 2009 Black Saturday bushfires. Bushfires can be started by various causes, including faults on electricity overhead networks.

Our customers view safety, including minimising bushfire risks, as a non-negotiable. Our 2021 research on customer valuation of service level improvements found a willingness to pay $11 for residential customers and $48 for business customers per annum for bushfire risk mitigation. Similarly, Monash University's Future Home Demand research found that safety ranked highest among seven household values that included sustainability, affordability and convenience.

We are also subject to regulatory obligations to minimise, as far as practicable (AFAP), the bushfire risk arising from our network assets. These obligations are set out in national and Victorian legislation and regulations, in particular the Victorian Electricity Safety (Bushfire Mitigation) Regulations and Victorian Electricity Safety Act.

Consistent with our regulatory obligations and customer preferences, our bushfire mitigation program for the 2026–31 regulatory period includes two broad focuses—rapid earth fault current limiters (REFCL) protection, and ongoing AFAP initiatives.

REFCL programs

In 2023, we completed the initial roll-out of REFCLs at 22 zone substations across our network. The roll-out of these REFCLs was mandated through the 2016 amendments to the Electricity Safety (Bushfire Mitigation) Regulations.[1] We are required to maintain the required capacity of these REFCLs as the nature of our network and customers change through time.

Further, our REFCL program includes works to maintain service levels given the adverse effect that REFCL settings have had on customer supply reliability. This program commenced in the 2021–26 regulatory period with a focus on REFCL-compatible automatic circuit reclosers, with the second phase now targeting remote controlled switches and sectionalisers.

AFAP programs

Consistent with our AFAP obligations, we have assessed several potential bushfire mitigation initiatives. These have been tested using risk-based cost-benefit analysis and the use of grossly disproportionate factors. Our AFAP process and bushfire modelling has been independently reviewed and verified to further ensure its robustness.

Our proposed AFAP programs include an additional non-mandated REFCL, at Horsham, to extend the benefits of REFCLs to a broader customer base. We are also proposing targeted initiatives to minimise risks from non-REFCL protected bare HV overhead conductor, including SWER lines, and our remaining population of HV wood crossarms.

Our proposed bushfire mitigation investments for the 2026–31 regulatory period is summarised in table 1. Specific business cases supporting each initiative are included as appendices within this document.

---

[1] Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016, S.R. No. 32/2016

TABLE 1 BUSHFIRE MITIGATION: FORECAST EXPENDITURE ($M, 2026)

PROGRAM	FY27	FY28	FY29	FY30	FY31	TOTAL
REFCL programs						
Maintaining REFCL compliance	18.9	35.9	9.8	15.7	14.3	94.6
Maintaining REFCL reliability	4.1	4.1	4.1	-	-	12.5
Other AFAP programs						
Minimising bushfire risks in the Horsham supply area	-	-	-	9.2	9.2	18.4
Minimising bushfire risks from bare 22kV conductors	5.2	5.2	-	-	-	10.5
Minimising bushfire risks from SWER lines	6.5	6.5	-	-	-	13.0
Minimising bushfire risks from HV wooden crossarms	4.8	4.8	4.8	4.8	4.8	24.0
Total	**35.4**	**56.6**	**18.7**	**33.9**	**28.3**	**172.9**

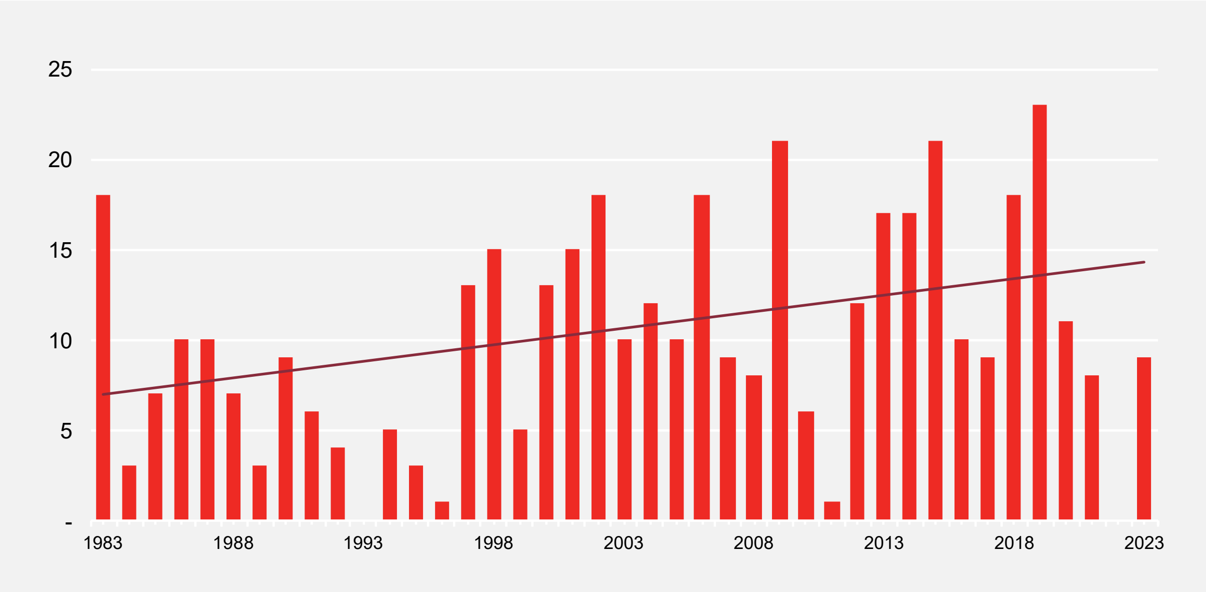
2. Background

Bushfires pose significant risks due to their potential catastrophic impact on the community with injuries, fatalities and significant damage to property and livestock. Our network most recently experienced bushfires in north-western Victoria in 2024 and 2025.

Faults on our overhead assets can result in catastrophic bushfires, depending on conditions. The 2009 Victorian Bushfires Royal Commission (VBRC) report into the Black Saturday bushfires identified that five of the 11 Black Saturday bushfires were caused by electricity assets.[2]

As our climate continues to change, conditions conducive to fire starts will increase further. As shown in figure 1, the annual number of total fire ban (TFB) days in our network area has been increasing by 0.2 days per year. This trend is forecast to continue, which will further heighten the risk of bushfires in our territory.

FIGURE 1 HISTORICAL TOTAL FIRE BAN DAYS IN OUR NETWORK



Source: Country Fire Authority

2.1 Bushfire and safety 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 includes 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. The obligations within these can be summarised as:

- the 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

2 Victoria Government, 2023, Electricity Safety (Bushfire Mitigation) Regulations 2023 Regulatory Impact Statement, p 10

- the 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
- the Electricity Safety Act 1998 requires us to minimise safety risk 'as far as practicable' including bushfire danger
- the Electricity Safety (Management) Regulations 2019 provide for the requirements, procedures and other matters relating to the acceptance of electricity safety management schemes
- the Electricity Safety (Bushfire Mitigation) Regulations 2023 provide the requirements for the preparation of bushfire mitigation plans for major electricity companies; and the inspection of overhead electric lines and supply networks
- the 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[3]' including bushfire danger arising from our network and reduce the risk of harm to the environment.

More specifically, the Victorian distributors must have in place an Electricity Safety Management Scheme (ESMS) and Bushfire Mitigation Plan (BMP) at all times, both of which are subject to acceptance by Energy Safe Victoria (ESV). These documents specify how we must comply with the regulatory requirements specified within the Electricity Safety (Management) Regulations 2019 and Electricity Safety (Bushfire Mitigation) Regulations 2023 respectively. They also specify the risk-based management approach in developing operating systems and management practices to identify the hazards and establish controls to minimise safety hazards and risks associated with the operation of the electricity network, as far as practicable (AFAP).

[3] Section 98: Electricity Safety Act 1998: General duty of major electricity companies – A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable – a) the hazards and risks to the safety of any person arising from the supply network; and b) the hazards and risks of damage to the property of any person arising from the supply network; and c) the bushfire danger arising from the supply network.

3. Our bushfire mitigation journey

Our bushfire mitigation journey spans multiple regulatory periods. Figure 2 summarises our journey to date and into the 2026–31 regulatory period.

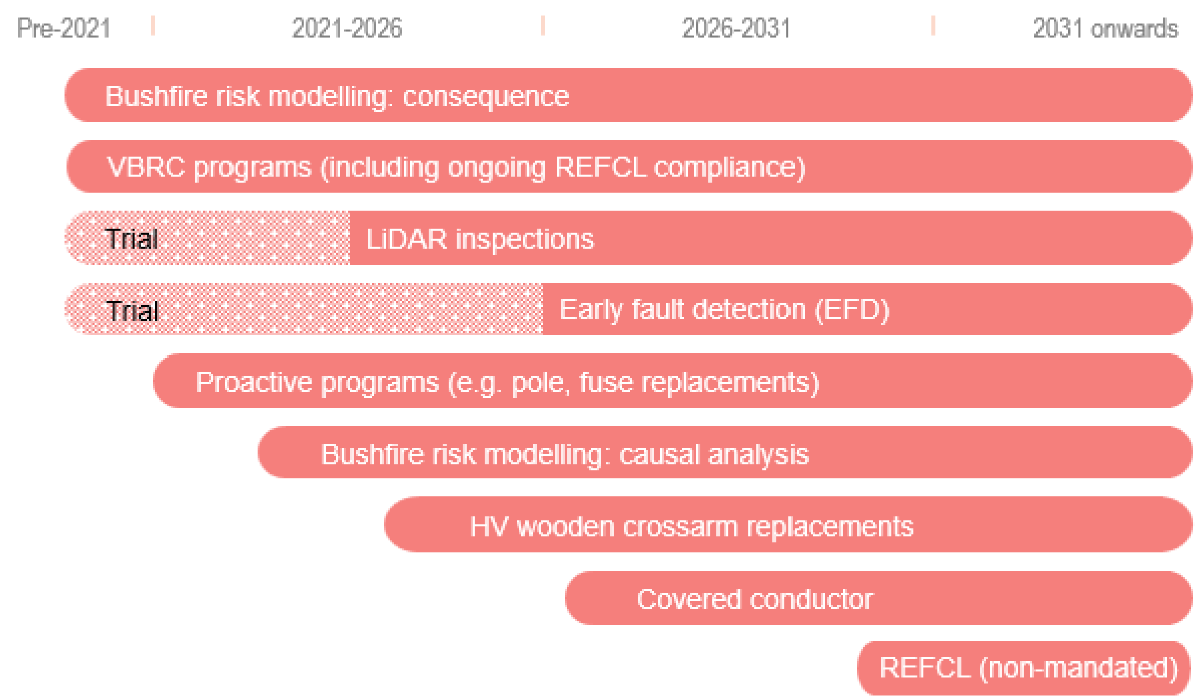
In the early stages of our journey, we increased our understanding of our bushfire risk through modelling and inspection. This included the development and application of bushfire consequence modelling (initially the 'Phoenix Rapidfire' model from CSIRO, and then 'Spark'), as well as using light detection and radar (LiDAR) technology as a key inspection tool to accurately identify and improve vegetation clearances.

We also focused on delivering the mandated Victorian Bushfire Royal Commission (VBRC) program to minimise bushfire risk to the timeframes set out in the Victorian Electricity Safety (Bushfire Mitigation) Regulation. For example, we replaced automatic circuit reclosers, installed armour rods and dampers, undergrounded high-risk areas as part of the Powerline Replacement Fund, and completed the initial REFCL roll-out.

Further initiatives to minimise bushfire risks under our AFAP obligations have been identified and implemented based on our enhanced understanding of bushfire risks. In the 2021–26 regulatory period this included the replacement of high-voltage (HV) expulsion drop-out fuses and low-voltage (LV) fuse-switch disconnectors, and an uplift in our wood pole replacement program. In 2023, we commenced HV wooden crossarm replacements in bushfire construction areas (BCA), and high bushfire risk areas (HBRA) in 2024.

In the 2026–31 regulatory period, we are proposing additional programs to further minimise bushfire risk as far as practicable. These programs are outlined in detail in the appendices within this document.

FIGURE 2 OUR BUSHFIRE MITIGATION JOURNEY



4. Bushfire risk assessment

Catastrophic bushfires are our highest enterprise risk and are defined as a bushfire initiated by electricity network assets, and/or employees and/or contractors carrying out work on the network.

Our staged approach to minimising catastrophic bushfire risk as far as practicable is shown below in figure 3. This approach is based on quantitative modelling that underpins our bushfire risk minimisation programs. This is in line with the AER's guidance for asset replacement planning.[4]

Given the criticality of mitigating bushfire risks effectively, and the complexity of bushfire modelling, we engaged GHD to independently test and validate the robustness of our approach.[5] The following sections provide a further description of each of the bushfire risk AFAP stages.

FIGURE 3 BUSHFIRE RISK AFAP STAGES OVERVIEW

4.1 Present risk exposure

Our bushfire risk assessment is underpinned by the quantification of risk in our bushfire risk model. This model is consistent with the bushfire risk model framework standard commissioned by the Victorian Government, and the AER's risk modelling expectations (e.g. considering likelihood and consequences of events).

Our bushfire risk model quantitatively assesses our bushfire risk exposure as well as its spatial and temporal distribution. The spatial factor is considered by calculating the risk at individual assets of the network. The temporal factor is considered by calculating the risk with different weather conditions, representative of the different Fire Danger Ratings at each asset location.

The bushfire risk quantification process uses the present (i.e. current) annualised bushfire risk based on existing controls, which includes those implemented as part of the VBRC program of works.

Figure 4 shows an overview of our bushfire risk quantification process, which determines our present risk exposure.

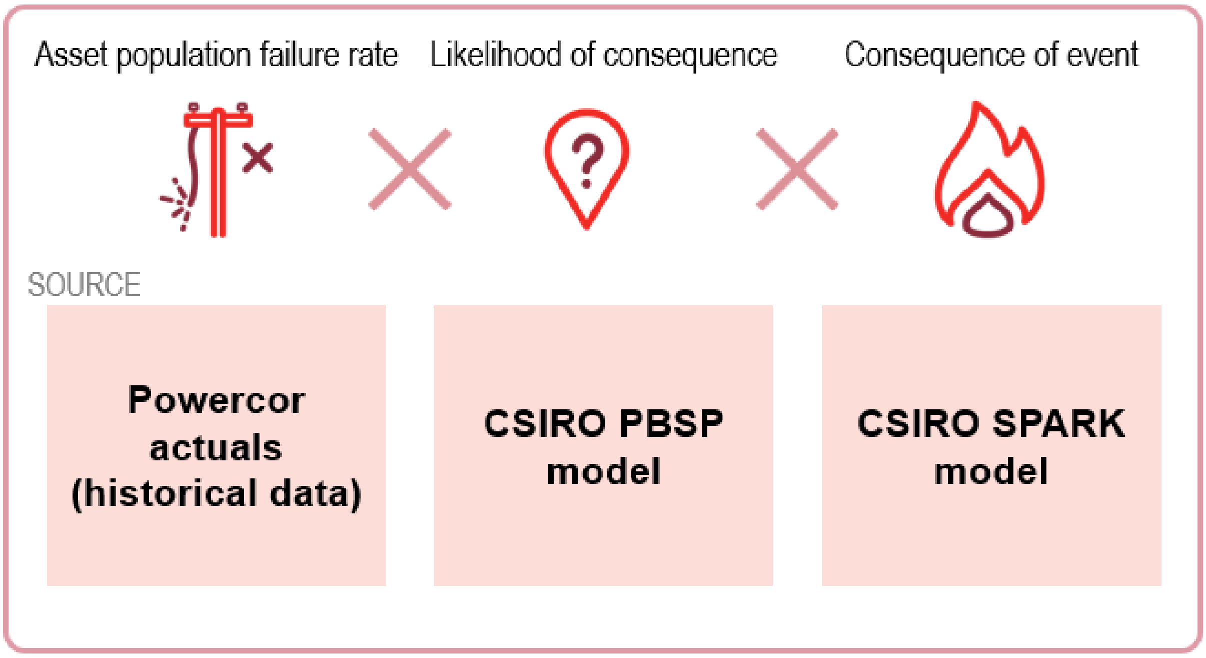
Overall bushfire risk for the network is based on the aggregation of the risk of our assets. The risk at a specific asset is the multiplication of the likelihood and consequence of bushfire for the asset.

---

4 Australian Energy Regulator, Industry practice application note, Asset replacement planning, January 2019

5 PAL ATT 3.07 - AFAP validation report - GHD - Jan2025 - Public

FIGURE 4 BUSHFIRE RISK QUANTIFICATION



4.1.1 Asset population failure rate

This is determined using network asset data and historical faults, as well as fire ignition data which is audited by the AER and ESV.

4.1.2 Likelihood of consequence

Our likelihood modelling is based on the Powerline Bushfire Safety Program (PBSP) model developed with CSIRO, and applied to our asset characteristics (the asset population failure rate).[6] It models the below two steps leading to the likelihood of an unsuppressed bushfire:

- the likelihood of an asset fault
- the conversion rate of a fault becoming a fire ignition.

4.1.3 Consequence of event

Consequence modelling considers both suppressed and unsuppressed fires. The consequence is considered 'minor' if the fire is suppressed or 'major' if the fire is unsuppressed.

The value of minor suppressed fires consider penalties specified under the F-factor scheme, as well as the average historical value of insurance claims related to fires.

The value of major unsuppressed bushfires are simulated using CSIRO's SPARK model, under different weather conditions.[7] Weather conditions for the fire simulations are selected for every asset and fire danger ratings from the closest weather station data. Consequence streams considered include the loss of life (based on statistical loss of life) and damage to property and our assets.

---

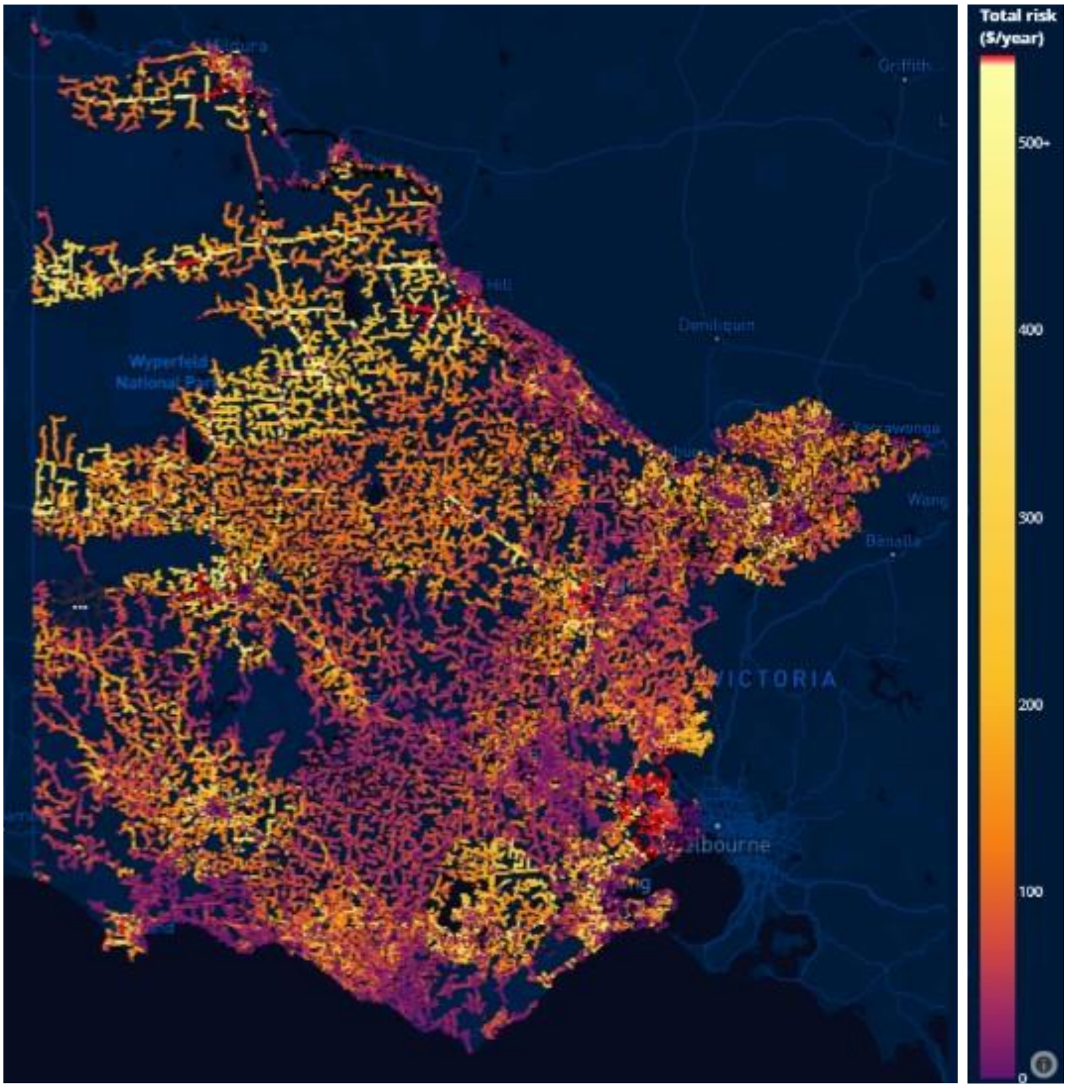
6 Dunstall, S., Towns, G., Huston, C. & Stephenson, A., 2016. PBSP Risk Reduction Model, Overview and Technical Details, s.l.: CSIRO

7 CSIRO's SPARK model is a wildfire simulation toolkit that allows consideration of localised variables, including local terrain characteristics and weather.

4.1.4 Bushfire risk exposure

Likelihood and consequence are combined to quantify the risk at each asset of the network under each weather condition. One of the key outputs of our present risk exposure quantification is the representation of spatial distribution of the risk. The spatial distribution of the risk is displayed in figure 5 below and shows that the highest risk is concentrated around populated areas. Most of the risk value is related to buildings and life loss.

FIGURE 5 PRESENT RISK EXPOSURE



4.2 Risk causes

Catastrophic bushfire risk causes were identified from analysis of our historical fire starts over the 2012–2023 period, with additional consideration given to fire starts that result in ground fires on TFB days (i.e. higher risk and fire consequence days). A summary of risk causes that result in ground fire starts on TFB days is shown in table 2.

The identification of risk causes allows for a targeted assessment of potential risk mitigation options.

TABLE 2 PROBABILISTIC CAUSE PROFILE: GROUND FIRE STARTS ON TFB DAYS

RISK CAUSES	PROBABILITY (%)
Leakage (insulator)	26.9
Vegetation	24.4
LV fused overhead line connector boxes, fused switching devices and junction boxes	19.6
LV Services	6.5
Overhead conductor connectors	6.0
Animals	5.0
Overhead conductors (bare)	3.5
Lightning and wind	1.8
Overhead conductors (other)	1.6
Distribution switchgear	1.5
HV fuses	0.8
Surge arrestors, crossarms and insulators	0.8
Distribution transformers	0.7
Third party contact	0.4
Poles	0.1

4.3 Control option identification

Control options to mitigate the identified fire start causes were identified through workshops with internal subject matter experts. These options build on existing controls and vary for each individual cause. The control option identification forms part of our risk management and quantification of residual risk, outlined in figure 6.

For example, insulator leakage is the largest cause of ground fire starts on TFB days historically. The options identified that may potentially control this risk include the following:

insulator washing (i.e. cleaning the insulator in-situ using high pressure water)

silicone treatment (i.e. spraying the insulator in-situ with a silicone solution to act as an additional insulating medium)

installing new insulators, which typically involves replacing the entire cross-arm due to cost efficiencies

covering the corresponding conductor to add additional layer of insulation

undergrounding the corresponding conductor to remove the need for the insulator.

4.4 Control option effectiveness

The effectiveness of the identified control options will vary, and as such, the effectiveness of each control options is quantified based on our experience and/or standard industry practice.

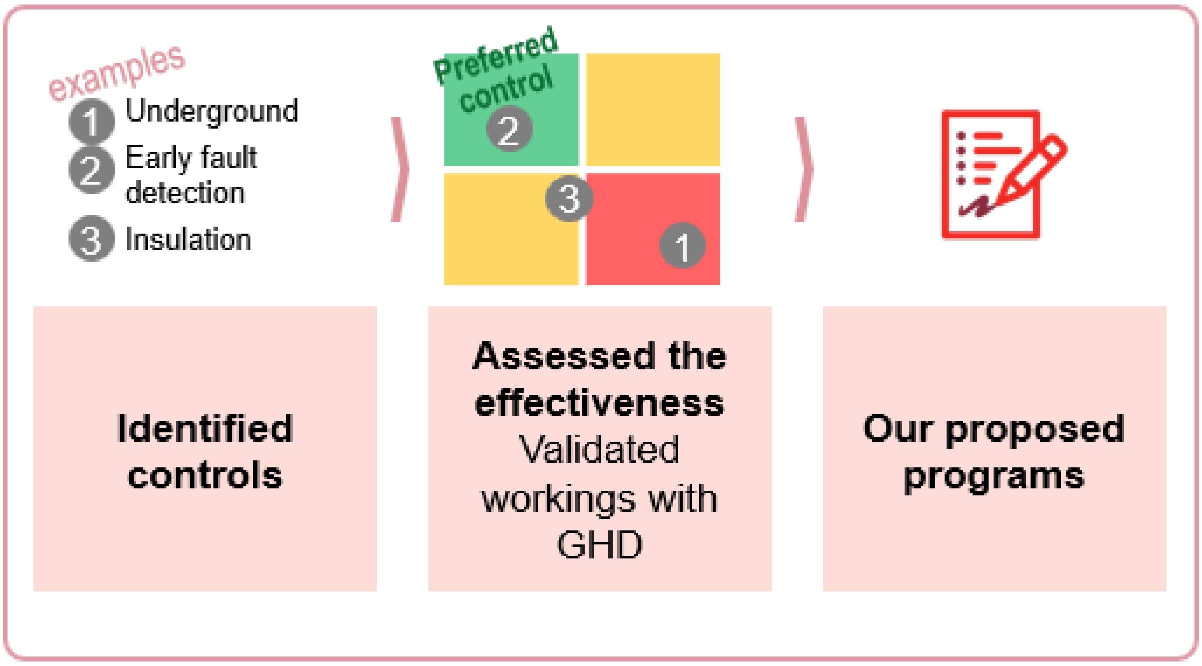
For instance, insulator washing, and silicone treatments are considered largely ineffective given several reasons:

- limited duration: washing can only remove surface contaminants temporarily; as soon as new pollutants accumulate, performance can diminish again
- silicone coating limitations: silicone treatments may provide initial hydrophobic properties, but they can wear off over time due to environmental factors, reducing their effectiveness
- maintenance frequency: both methods require frequent application or washing, leading to increased maintenance costs and effort
- environmental impact: chemicals used in washing and silicone treatments can have negative environmental consequences, raising concerns about their long-term sustainability
- effect on insulator integrity: aggressive washing techniques may damage the insulator surface, potentially leading to premature failure.

At the other end of the spectrum, undergrounding the asset is assessed as being fully effective (as the insulator is removed from service).

Our effectiveness criteria and assessments were independently validated by GHD.[8] This independent assessment found the control effectiveness criteria yielded appropriate outcomes, with two non-critical findings identified.[9]

FIGURE 6 CONTROL OPTION EVALUATION



8 PAL ATT 3.07 - AFAP validation report - GHD - Jan2025 - Public

9 This included formal communication of the current control effectiveness ranges and setpoints with stakeholders, and a recommendation to re-evaluate the effectiveness ranges and ratings periodically to cater for technological advances that may increase reliability of assets. We have an action plan in place to address these findings.

4.5 Estimate control cost

In addition to varying effectiveness levels, the cost to implement different control options varies. Control costs for each option are estimated per fire risk area, by determining the population of relevant assets per fire risk area and historical asset replacement costs.

4.6 AFAP analysis

The AFAP analysis considered the following:

- risk reduction provided by the option (considering the expected life span of the proposed solution)
- cost of option implementation
- cost benefit analysis that considers the disproportionality factors applied.

An initial cost-benefit analysis was undertaken based on the AER's RIT-D guidelines inclusive of application of disproportionate factors. These are used to quantify the cost of a fatality and to justify the appropriate level of investment to reduce the risk of harm in line with expectations of the general public.

Options which failed this test were determined to be 'not practicable'. This comprehensive process is referred to as the AFAP analysis which was part of the independent assessment and validation by GHD.[10]

A combination of controls were packaged with due consideration to minimise any overlap of cause mitigation. For example, wood crossarm failures caused by insulator current leakage that result in crossarm fires are not prevented by REFCL protection, as shown in figure 7.

FIGURE 7 OPTIONS PACKAGING

Bushfire risk causes	Control option	Cause addressed?	Control option	Cause addressed?
Insulator (leakage)	Proactive replacements of HV wooden cross-arms	Yes	Additional REFCL protection (on selected feeders)	No
Vegetation		No		Yes
LV FOLCBs, FSDs, JBs		No		No
Services		No		No
OH connectors		No		No
Animal contacts		No		Yes
OH conductor (bare)		No		Yes
Lightning / weather (excl. vegetation)		No		Yes
OH conductor (other)		No		Yes
Distribtuion switchgear		No		Yes
HV fuses		No		No

Hence, crossarm replacements were recommended to mitigate fires started due to insulator leakage, which would be in addition to the existing REFCL mitigating control in place.

Case study: fire starts caused by leaking insulators

10 PAL ATT 3.07 - AFAP validation report - GHD - Jan2025 - Public

To address the bushfire risk due to insulator leakage, we assessed several options in 2023 dollars.

Average annual bushfire risk of a wood HV crossarm in HBRA is approximately $710 per annum.

Insulator washing would incur approximately $300 annual cost with trivial risk reduction of approximately $1 per annum. This would make it an economically non-viable option.

Similarly, applying silicon would incur approximately $500 cost once every two years with trivial risk reduction of approximately $1 per annum. This would make it an economically non-viable option.

Installing covered conductor would incur approximately $23,000 cost over its design life of approximately 30 years with approximately $715 risk reduction per annum. This would make it an economically non-viable option.

Similarly, undergrounding bare overhead conductor would incur approximately $90,000 cost over its design life of approximately 50 years with approximately $730 risk reduction per annum. This would make it an economically non-viable option.

Finally, proactively replacing HV wood crossarms with new crossarm and insulators would incur approximately $4,510 cost over its design life of approximately 50 years with approximately $710 risk reduction per annum. This would make it an economically viable option.

Therefore, proactively replacing HV wood crossarms in HBRA with steel crossarms is being pursued.

4.7 AFAP recommendations

The outcomes of our AFAP assessment are reflected in our proposed bushfire mitigation program for the 2026–31 regulatory period, and discussed in more detail in the following appendices. Specifically:

- appendix C – minimising bushfire risks in the Horsham supply area
- appendix D – minimising bushfire risks from bare 22kV conductors
- appendix E – minimising bushfire risks from SWER lines
- appendix F – minimising bushfire risks from HV wooden crossarms.

The proposed bushfire mitigation program also includes two REFCL programs focussed on maintaining REFCL compliance and maintaining service levels given the adverse effect that REFCL settings have had on customer supply reliability:

- appendix A – maintaining REFCL compliance
- appendix B – maintaining REFCL reliability.

A

MAINTAINING REFCL COMPLIANCE

A Maintaining REFCL compliance

The 2009 Black Saturday bushfires across Victoria were one of Australia's worst bushfire disasters, with 400 individual fire ignitions resulting in 173 lives lost.[11] Six days after the bushfires, the Victorian Government established the Victorian Bushfire Royal Commission (VBRC) to consider how bushfires can be better prevented and managed in the future.

On 1 May 2016, the Victorian Government amended the Electricity Safety (Bushfire Mitigation) Regulation 2013 with the introduction of the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 (Amended Bushfire Mitigation Regulations). Since then, further amendments have been published, with the current applicable regulations specifying the following:[12]

- compliance is required at 22 of our zone substations, with a ‘points’ value assigned to each substation based on bushfire risk level
- requires each polyphase electric line originating from every selected zone substation specified in Schedule 1 to have the 'required capacity'.

We achieved initial compliance by the required date (May 2023), however, as network characteristics continue to change, further investment is required to ensure that compliance is maintained. That is, the Regulations also require that:

- annual testing of the required capacity must be undertaken before the specified bushfire risk period each year and a report detailing the test results must be submitted to Energy Safe Victoria (ESV)
- each new or replaced line with a nominal voltage from 1 kV to 22 kV inclusive must be covered or undergrounded from 1 May 2016 in 33 prescribed electric line construction areas.

Further, the Victorian Government introduced the Bushfire Mitigation Civil Penalties Scheme via an amendment to the Electricity Safety Act 1998. The scheme includes financial penalties of up to $2 million per point for any difference between the total number of required substation points prescribed in the Amended Bushfire Mitigation Regulations and the substation points we have achieved. The scheme also includes a daily penalty up to $5,500 per point for each day that a contravention with the Amended Bushfire Mitigation Regulations persists.

Annual capacity testing is undertaken to ensure that we maintain compliance with all obligations at each REFCL site every year. We have maintained historical compliance with all relevant REFCL requirements that REFCLs have been mandated.

This business case seeks funding to maintain compliance through the 2026–31 regulatory period as the network grows and changes.

A summary of our assessment of the least cost technically acceptable REFCL projects and their required expenditure is described in table 3 below.

---

11 More information available at: https://www.nma.gov.au/defining-moments/resources/black-saturday-bushfires

12 The current regulations are Electricity Safety (Bushfire Mitigation Duties) Regulations 2017.S.R. No. 85/2017, and Electricity Safety (Bushfire Mitigation) Regulations 2023. S.R. No. 40/2023.

TABLE 3 REFCL COMPLIANCE PREFERRED OPTIONS AND EXPENDITURE ($M, 2026)

LOCATION	PREFERRED OPTION	COST
Ararat	Isolating substations	0.3
Ballarat East stage 2	New transformer, additional REFCL and iso subs	14.6
Bendigo Terminal Station	Feeder reconfiguration	3.3
Bendigo	New transformer, additional REFCL and transfers	13.4
Colac	REFCL mini grids	7.8
Eaglehawk	New transformer, additional REFCL and transfers	12.8
Gheringhap	Feeder reconfiguration	3.7
Gisborne	New REFCL and feeder arrangement	9.3
Koroit	Isolating substations	0.6
Terang	New REFCL and feeder transfers	5.6
Torquay	Feeder reconfiguration	3.1
Tranche one remediation	Phase balancing capacitors / swapping	2.3
Winchelsea	Isolation substations	5.3
Woodend	New transformer, additional REFCL and transfers	12.6
Total	**Preferred options**	**94.6**

A.1 Identified need

The length and characteristics of the network supplied by a zone substation regularly change due to new connections, network upgrades and maintenance work. These changes can affect the capacity of REFCL units to continue to meet the requirements mandated by the Regulations.

We have an obligation to maintain compliance at our zone substations in response to these changes, and the identified need, therefore, is to meet these compliance obligations.

A.1.1 Adoption of damping current as the assessment metric

In our 2021–26 regulatory proposal, we used forecast network capacitive charging current as the metric to assess REFCL performance. We assessed REFCL sites based on whether the forecast network capacitive charging current exceeds the current capability of each REFCL.

Damping current is the combination of network capacitance and network damping ratio, which is directly related to the system's ability to limit fault currents to safe levels. Based on our further extensive experience in implementing and maintaining REFCL systems in our network, to enable the use of a consistent threshold limit across all REFCL sites, we have now adopted damping current as the REFCL performance assessment metric. We conduct annual testing of each REFCL system to confirm the damping current performance.

For each REFCL, we assess the forecast damping current against the damping current threshold limit, which can vary by asset based on the sensitivity of the REFCL protection settings to capacitance. Where this threshold limit is exceeded at a REFCL site, it indicates a probable non-compliance issue.

Our damping current forecasting methodology

Network capacitive current increases with network size as it is proportional to line length. Underground cables increase network capacitive current more than overhead lines due to their physical construction with significantly closer conductor spacing. Hence, we focus on underground cable growths in our capacitive current forecasting.

We forecast network capacitive current based on:

- an average five-year historical growth rate
- new underground residential distributions from masterplans
- removal of the following to prevent double counting—one-off programs of works such as the undergrounding of overhead networks as part of the VBRC Powerline Replacement Program, and in progress underground residential distribution.

The network damping ratio is based on the annual measured value on a total fire ban day.

We then multiply the forecast network capacitive current with the network damping ratio to obtain our damping current forecast.

A.1.2 Tranche one remediation works

Remediation works are proposed to bring all REFCL tranche one substations to the same standard of performance as more recent installations, particularly in relation to low voltage balancing capacitors and phase swapping. The tranche one REFCL remediation works are expected to be focused largely on Woodend and Gisborne as these were the first two zone substations where REFCLs were commissioned.

The later tranche one zone substations started to benefit from the lessons learnt at the Gisborne and Woodend zone substations. We propose to review all networks associated with tranche one zone substations as part of the remediation works to ensure they meet the network balance criteria, which ensures REFCLS only operate for legitimate faults.

A.2 Options framework

This section sets out our approach to maintaining REFCL compliance.

A.2.1 Our overall approach

We propose to maintain compliance with our REFCL obligations in the 2026–31 regulatory period by:

- preventing REFCL mal-operation by balancing capacitance across phases in our existing REFCL sites
- maintaining REFCL performance by ensuring existing sites continue to have the required capacity as defined by the Electricity Safety (Bushfire Mitigation) Regulations. Where a site is forecast to

no longer have the required capacity, one of the options listed in table 4 (below) will be implemented. These projects typically require capital expenditure.

A.2.2 Defining technically credible options

We have identified six potential credible options, which depending on the site may be used in combination, to address REFCL non-compliance at each site.

Non-network solutions are not a credible option to address REFCL non-compliance and have been excluded from the six potential options set out in table 4.[13]

All technically credible options are identified by assessing the characteristics of each zone substation to determine the feasibility of each of the six potential options.

Once the technical feasibility of an option has been assessed, we then assess the demand forecasts to ensure that asset ratings are sufficient to meet any increased load.

Table 4 shows the options sorted from lowest cost (option one) to highest cost (option five) in order of unit capital costs. The relative cost of each option is indicative only as multiple units of an option may be required to address damping current exceedance at a zone substation.

For example, two REFCL mini-grids or four isolating substations may be required to achieve compliance at a site where only one new REFCL is needed to address damping current exceedance. Depending on the number of units required by each option, the actual cost of options may change for a given site.

[13] Non-network solutions cannot provide REFCL compliance under clause 5.17.4(c) and (d) of the National Electricity Rules. This determination was published in accordance with clause 5.17.4(d) on 29 July 2019 and no responses were received regarding this determination.

TABLE 4 TECHNICALLY CREDIBLE OPTIONS TO ADDRESS REFCL NON-COMPLIANCE

OPTION		DESCRIPTION AND FEASIBILITY CONSIDERATIONS
1	Feeder reconfiguration	The forecast growth in damping current may be accommodated by the existing REFCL units by reconfiguring the zone substation feeders to balance the damping current between the existing units. It may also be possible to transfer feeders between REFCL-protected zone substations.
2	Isolating substations	Electrically isolating a section of the 22kV feeder where the network is fully underground will reduce damping current. The feasibility of this option depends on network design and the availability of land for the isolating substation.
3	Isolating substation with a REFCL (REFCL mini-grid)	Pairing an isolation substation with a REFCL unit means that the isolated network can use overhead lines that will be protected by the new REFCL unit. The feasibility of this option depends on the availability of land for the substation and REFCL.
4	Installation of an additional new REFCL	The feasibility of this option depends on whether the existing zone substation has space to accommodate the additional REFCL(s) required. This option may necessitate the addition of a new zone substation transformer if all existing substation zone substation transformers already have a REFCL unit connected.
5	Mini zone substation with a dedicated power transformer	Construction of an adjacent 'mini zone substation' with a dedicated power transformer, 22kV circuit breakers and additional feeder exits.
6	New zone substation	Construction of a new zone substation may be required if other options are not feasible. In the case where a new zone substation is required, significant feeder reconfigurations will be necessary where selected existing 22kV feeders are redirected to the new zone substation.

A.2.3 Assessing least cost options for each site

We have estimated the cost of each technically credible option based on recent historical costs of similar projects.

In determining the preferred solution for each site, we identify the feasibility of each of the credible options and then identify the least cost option to meet the specified need. In certain instances, we have considered whether a combination of options is more feasible to deliver a lower total cost solution. For example:

- we may have considered whether a reduced scope of isolating substations (subset of option two) can be used in combination with options three, four or five to deliver a lower total cost solution. If so, this combination of options should be selected

- if more than one additional REFCL unit is required in options three, four or five, we may have assessed the feasible trade-offs to reduce the number of additional REFCLs by using a number of isolating substations to reduce the damping current.

Our approach to scoping and costing the selected option is consistent with our contingent project application for tranche three of the REFCL installation program during the 2021–26 regulatory period. As such, our approach takes account of the lessons learnt through the implementation of the REFCL program, the actual costs incurred and the best available cost information in relation to equipment and materials.

A.3 REFCL projects

This section describes the individual circumstances, needs, options and expenditure forecasts of each REFCL compliance project. Further detail is provided in the corresponding models.

A.3.1 Ararat zone substation

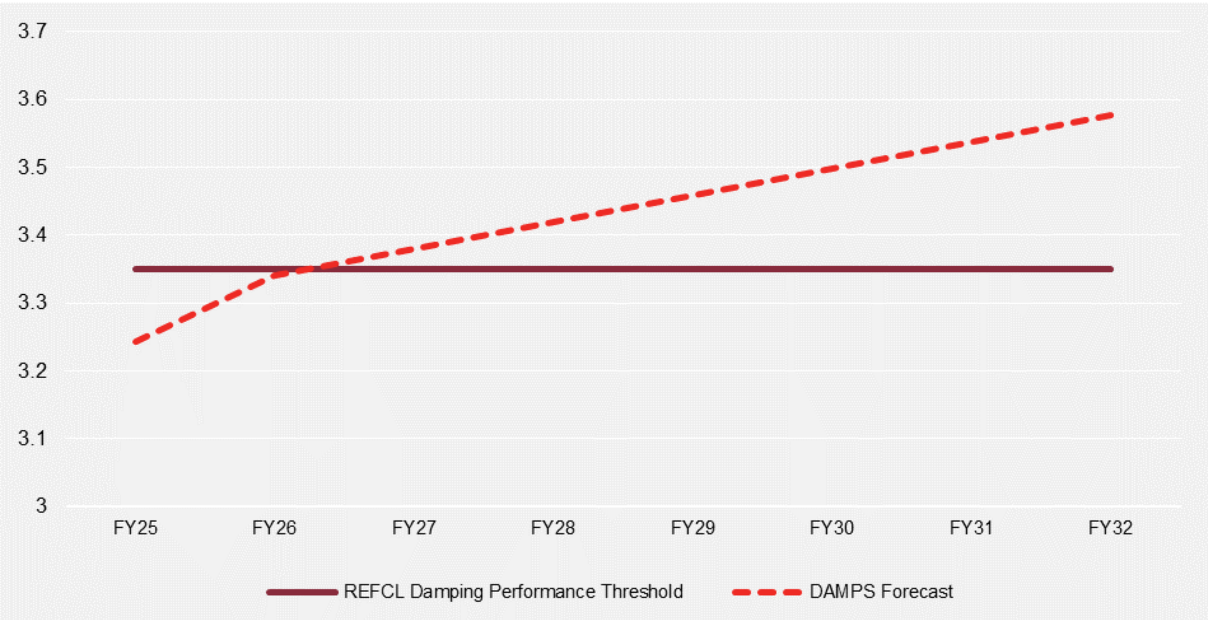
Ararat (ART) zone substation is situated on the 66kV network in the Central Highlands region. It is supplied from the Ballarat Terminal Station and also connected to Buangor and Stawell zone substations via a single 66kV line to each substation.

ART currently consists of two 10 MVA 66/22kV transformers supplying our 22kV network. Due to the recent REFCL compliance requirements, there is one existing REFCL earthing unit. ART is a 1-point substation.

Site identified need

REFCL damping current limits are forecast to be exceeded at ART in 2027, as shown in figure 8 below.

FIGURE 8 ART REFCL DAMPING CURRENT FORECAST



In order to maintain compliance with the Act, we must address the network damping current issues by 2027.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 5 ART OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	Yes	This option involves transferring part of an ART feeder to Stawell (STL). This option assumes that overhead construction is feasible. If underground construction is required, this option would require a new REFCL installation. The cost of this option is: 2.5M.
Option 2 - isolating substations	Yes	The option of electrically isolating sections of underground cable with high damping current supplied by the ART zone substation from the REFCL protected network is feasible. The cost of this option is: 0.6M.
Option 3 - REFCL mini grid	Yes	This option involves the establishment of one REFCL mini grid on bus 2 at ART. The cost of this option is: 7.0M.
Option 4 - adding a new REFCL	Yes	This option requires the installation of an additional REFCL at ART and to augment the distribution network to transfer network to the new REFCL. The cost of this option is: 5.0M.
Option 5 - mini zone substation	No	This option has not been considered as ART zone substation has one REFCL currently installed.
Option 6 - new zone substation	Yes	While this option is feasible, it was not progressed as other lower cost options were technically feasible.

Preferred option

Option 2 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option.

Work has commenced in the 2021–26 regulatory period to resolve a REFCL damping current constraint using isolating substations. This work is expected to continue into the 2026–31 regulatory period.

TABLE 6 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	0.3	-	-	-	-	0.3

A.3.2 Ballarat East zone substation

In our 2021–26 regulatory proposal to the AER, we applied and were approved to establish the new Ballarat East (BAE) zone substation to address REFCL compliance, as the primary driver, and demand growth, as the secondary driver. The new BAE zone substation will establish a new zone substation site, one new REFCL unit, one new 33MVA 66/22kV transformer, one new 22kV switchboard and three new distribution feeders.

Site identified need

REFCL damping current limits are forecast to be exceeded at both BAN and BAS by 2029, as shown in figure 9 and figure 10 below.

FIGURE 9 BAN REFCL DAMPING CURRENT FORECAST

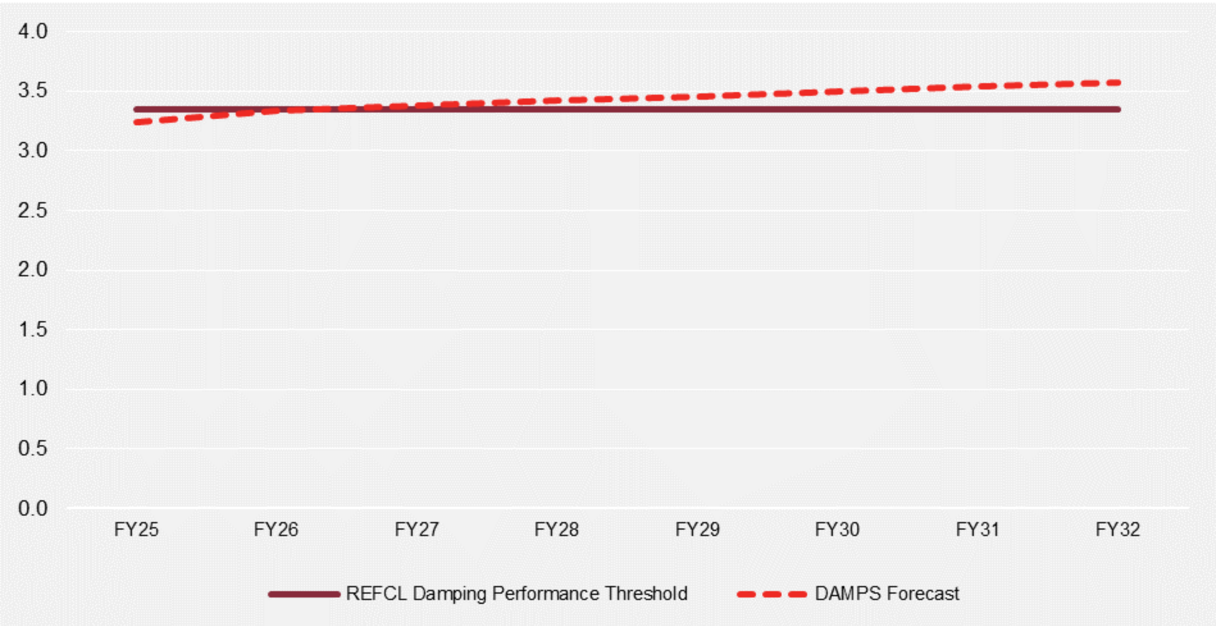
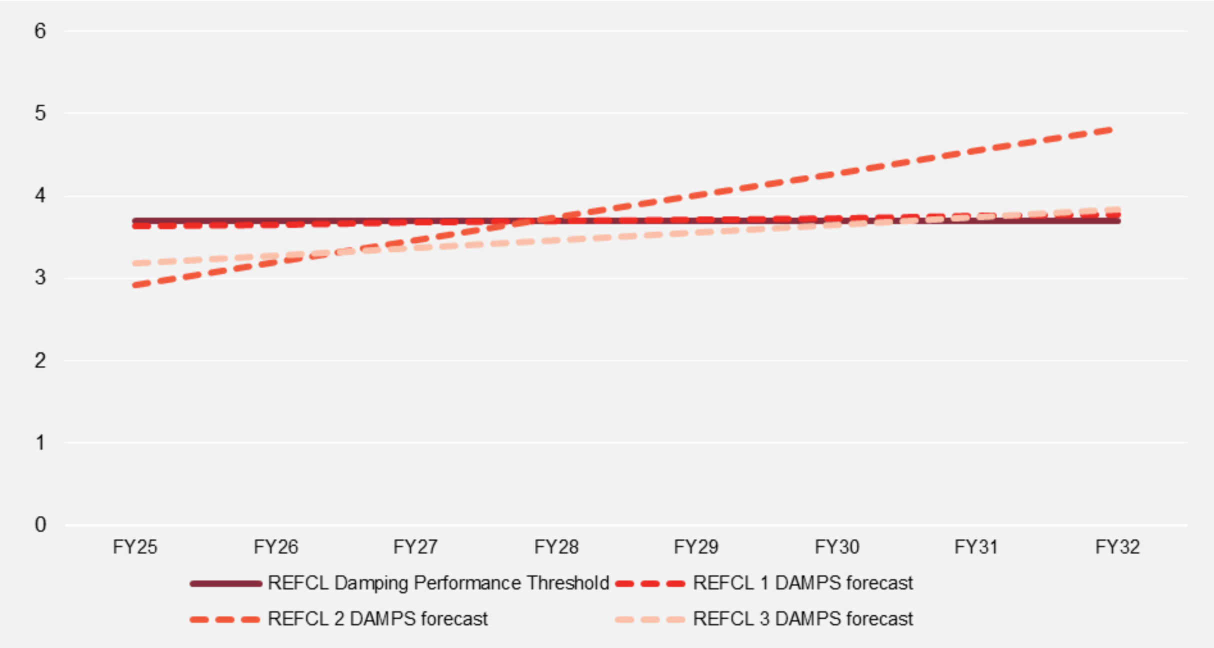


FIGURE 10 BAS REFCL DAMPING CURRENT FORECAST



Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 7 BAE AND BETS SPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	There are no viable options available to transfer network damping current due to a lack of REFCL transfer capacity in the existing BAN and BAS and new BAE substation networks. Therefore, this option is technically infeasible.
Option 2 and 3 - REFCL mini grid and Isolating substations	Yes	This option is a combination of the isolating substations, REFCL mini grid options. A new REFCL will be required in the 2031-36. It involves establishing: • four isolation substations in the BAN and BAS networks in 2027, 2029, 2031 and 2033 • one REFCL mini grid in 2026-27 • one new power transformer and REFCL at BAE zone substation in 2033-35. The present value cost of this option is: 11.9M (2026).
Option 4 - adding a new REFCL	Yes	This option involves establishing a new power transformer and REFCL at BAE. Isolation substations will be required in the 2031-36 regulatory period. It involves establishing: • One new power transformer and REFCL at BAE zone substation in 2026-29 • Three isolation substations in the BAN and BAS networks in 2031, 2033 and 2035. The present value cost of this option is: 9.4M (2026).
Option 5 - mini zone substation	Yes	This option requires the installation of a second 66/22kV transformer along with associated primary and secondary equipment and a new REFCL. This new transformer will provide support to the one transformer planned to be installed at BAE by 2025. The present value cost of this option is: 19.2M (2026).
Option 6 - new zone substation	No	This option has not been considered for the Ballarat supply area as the new BAE zone substation is due for completion in the 2021–26 regulatory period.

Preferred option

Option 4 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

This brings forward the establishment of a new transformer and REFCL to the 2026–31 regulatory period and reduces the number of isolation substations and REFCL mini grids required across both regulatory periods.

TABLE 8 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	0.7	13.2	0.7	-	-	14.6

A.3.3 Bendigo TS (BETS)

Bendigo Terminal Station (BETS) is situated on the Victorian 220kV network connected to the Ballarat, Kerang and Shepparton terminal stations via single circuit 220kV lines.

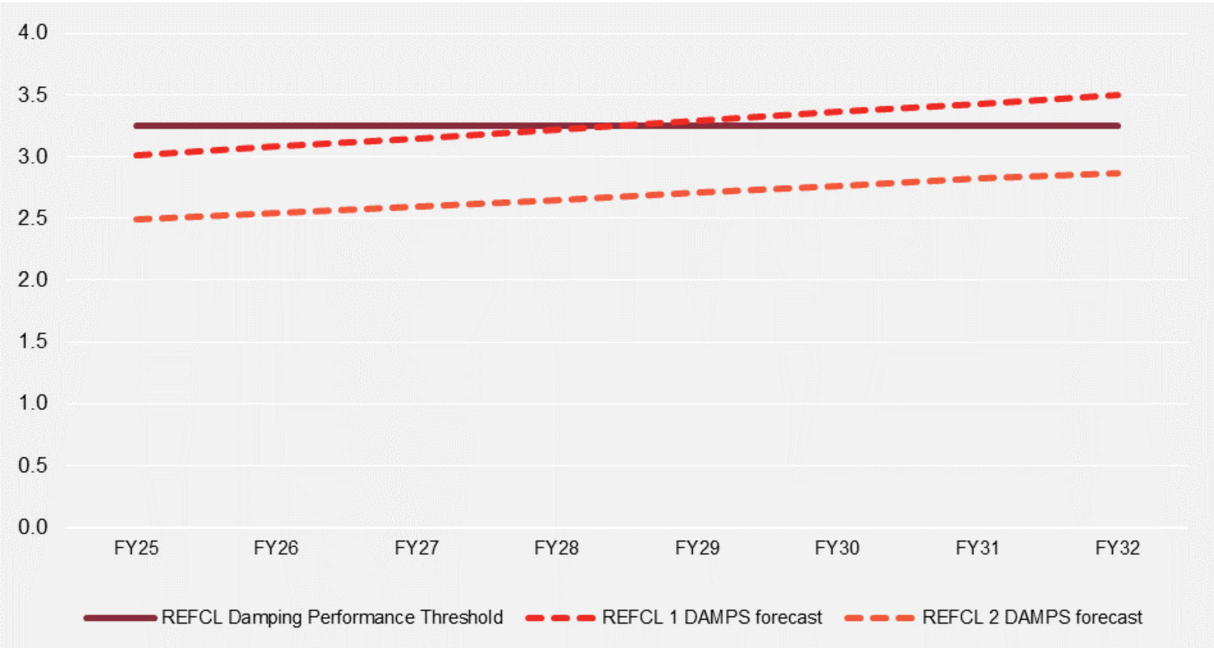
BETS has one 150MVA and one 125MVA 220/66kV transformer supplying the 66kV network and two 75 MVA 220/22kV transformers supplying our 22kV network. The 22kV bus is separated into two banks of transformers with a normally open bus-tie circuit breaker for fault level containment.

Two REFCLs were installed at BETS as part of the tranche two REFCL installation program. BETS is a 5-point substation.

Site identified need

REFCL damping current limits are forecast to be exceeded at BETS in 2029, as shown in figure 11 below.

FIGURE 11 BETS REFCL DAMPING CURRENT FORECAST



To maintain compliance, we must address the network damping current issues by 2029.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 9 BETS OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	Yes	This option involves several minor augmentations to transfer sections of the network. This option is dependent on the preferred option of the Eaglehawk (EHK) REFCL business case where a third transformer and REFCL is proposed for installation in 2027. The cost of this option is: 3.3M (2026).
Option 2 - isolating substations	No	This option is not feasible as there are no considerable sections of underground cable to isolate, as underground cable is in the network backbone, scattered throughout the network in small sections or already isolated.
Option 3 - REFCL mini grid	Yes	This option involves establishing one REFCL mini grid on the BET007 feeder in the Mandurang area. The cost of this option is:7.8M (2026).
Option 4 - adding a new REFCL	No	This option is not appliable as BETS is supplied from a terminal station.
Option 5 - mini zone substation	No	This option is not appliable as BETS is supplied from a terminal station.
Option 6 - new zone substation	Yes	This option involves establishing a new zone substation. The new zone substation will reduce the damping current on existing REFCL by transferring sections of the BETS network to the new zone substation. The cost of this option is: 50.1M (2026).

Preferred option

Option 1 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined in table 10.

TABLE 10 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	0.6	2.7	-	-	-	3.3

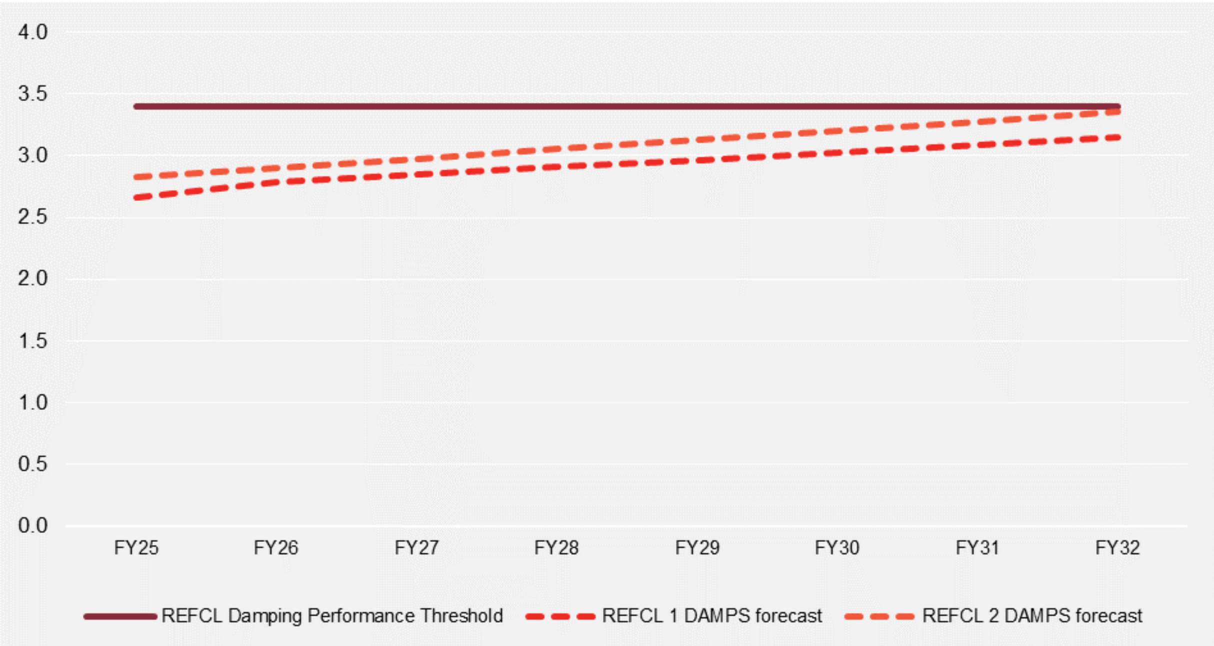
A.3.4 Bendigo (BGO)

The zone substation in Bendigo is supplied by sub-transmission lines from the Bendigo terminal station (BETS). It supplies the City of Bendigo and the rural area to the east. The BGO zone substation is currently comprised of two 20/27/33MVA transformers operating at 66/22kV and has two REFCLs.

Site identified need

REFCL damping current limits are forecast to be exceeded on the BGO bus 2 by 2032, as shown in figure 12 below.

FIGURE 12 BGO REFCL 1 AND 2 DAMPING CURRENT FORECAST



Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 11 BGO OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	There are no viable options available to transfer network due to a lack of REFCL transfer capacity in the neighbouring Eagle Hawk and Bendigo Terminal zone substation networks. Therefore, this option is technically infeasible.
Option 2 - isolating substations	No	This option has not been considered due to: • The high number of isolation transformers required • insufficient underground cable sections for isolation to achieve the required reduction in damping current • The isolatable sections of the BGO network will likely be constrained for space to install several isolation substations.
Option 3 - REFCL mini grid	Yes	This option involves the establishment of two REFCL mini grids. The isolation of network sections from the remainder of the BGO network does however limit operational flexibility. Two mini grids are required to ensure that feeder thermal constraints are not exceeded due to the 6MVA isolation transformer ratings. This option will also require new switchgear, land, fencing and HV and LV connections for each of the REFCL mini grids. The cost of this 15.6M (2026).
Option 4 - adding a new REFCL	Yes	This option requires the installation of a third 66/22k transformer and associated switchgear and secondary systems, the installation of a third REFCL. Two feeders will be transferred to the new transformer and associated REFCL. The cost of this option is: 13.4M (2026).
Option 5 - mini zone substation	No	This option has not been considered BGO zone substation has space for an additional REFCL.
Option 6 - new zone substation	Yes	This option involves establishing a new substation to transfer feeders to and reduce the damping current of the BGO network. This option includes 22kV distribution works to enable the load transfers from BGO and is considered feasible. The cost of this option is 50.1M (2026).

Preferred option

Option 3 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

TABLE 12 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	-	0.6	2.5	10.2	13.4

A.3.5 Colac (CLC)

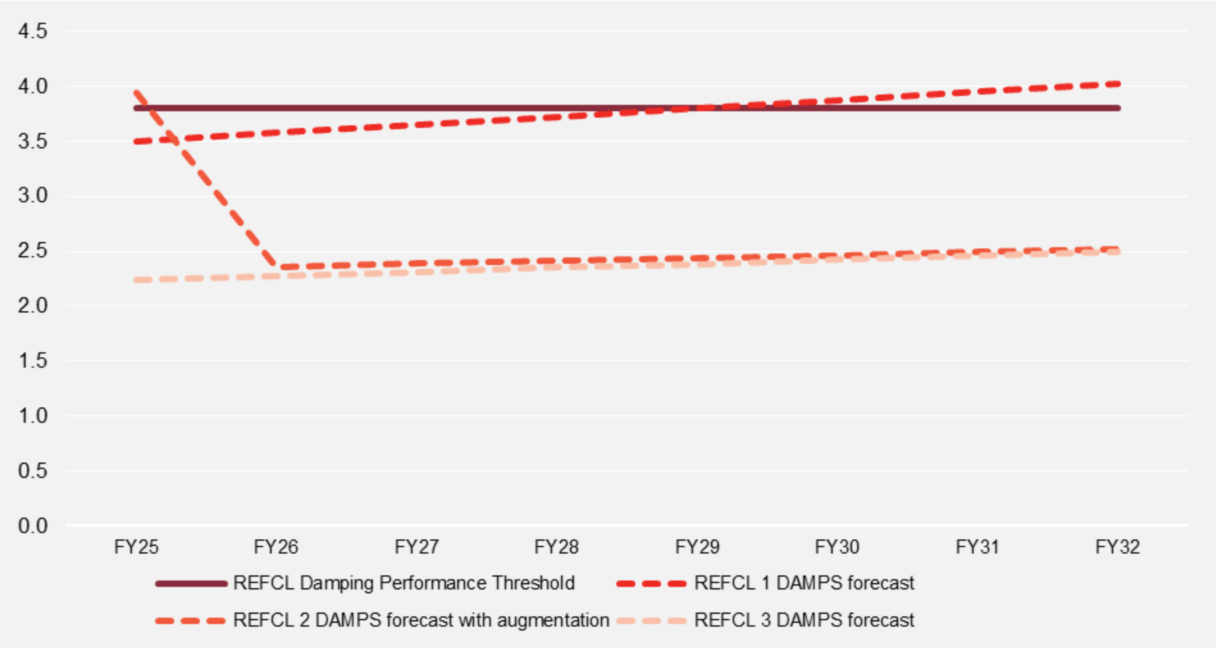
The zone substation in Colac (CLC) is supplied by sub-transmission lines from both Geelong and Terang terminal stations. It supplies the Colac township and the surrounding rural areas north to Beeac, east to Lorne, and south to Apollo Bay.

The Colac substation currently consists of three 66/22kV transformers, two of which are rated at 25/33MVA and one rated at 10/13MVA. Due to the recent REFCL compliance requirements there are three existing REFCL earthing units for these transformers.

Site identified need

REFCL damping current limits are forecast to be exceeded at CLC bus 1 in 2029, as shown in figure 13 below. A planned project is already in progress to resolve the REFCL compliance constraint at CLC bus 2 in FY26.

FIGURE 13 CLC REFCL 1, 2 AND 3 DAMPING CURRENT FORECAST



To maintain compliance we must address the network damping current issues by 2029.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 13 CLC OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	There are no viable options available to transfer network due to a lack of REFCL transfer capacity in the neighbouring Camperdown and Winchelsea zone substation networks. Therefore, this option is technically infeasible.
Option 2 - isolating substations	No	There are no significant sections of underground cable to isolate from the RECFL networks at CLC zone substation. Underground cables sections at CLC zone substation either form part of feeder backbones, making isolation technically infeasible, or are scattered in smaller sections throughout the CLC network.
Option 3 - REFCL mini grid	Yes	This option involves the establishment of one REFCL mini grid. The isolation of network sections from the remainder of the CLC network does however limit operational flexibility. This new REFCL mini grid will remove the damping constraint on the CLC bus 1 and address the charging current limit on CLC013. The cost of this option is: 7.8M (2026).
Option 4 - adding a new REFCL	No	The CLC zone substation has three existing power transformers and REFCLs connected. Therefore, the installation of a fourth REFCL at CLC would require an additional transformer, which would require significant reconfiguration of the site.
Option 5 - mini zone substation	Yes	This option involves extending the existing zone substation to establish a mini zone substation. The works for this option would include transfer of sections of feeders from bus 1 to the new mini zone substation bus. This option is considered because land is available at the CLC zone substation for this option which reduces the overall cost of the works. The cost of this option is:12.8M (2026).
Option 6 - new zone substation	Yes	This option involves the establishment of a new substation in the region to transfer selected feeders to and reduce the damping current of the CLC network. This option includes 22kV distribution works to enable the load transfers from CLC and is considered feasible. The advantages of this option include improved operational flexibility, reliability and supply security. The cost of this option is 50.1M (2026).

Preferred option

Option 3 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

TABLE 14 EXPENDITURE FORECAST FOR THE PREFERRED OPTION (2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	1.0	6.8	-	-	-	7.8

A.3.6 Eaglehawk (EHK)

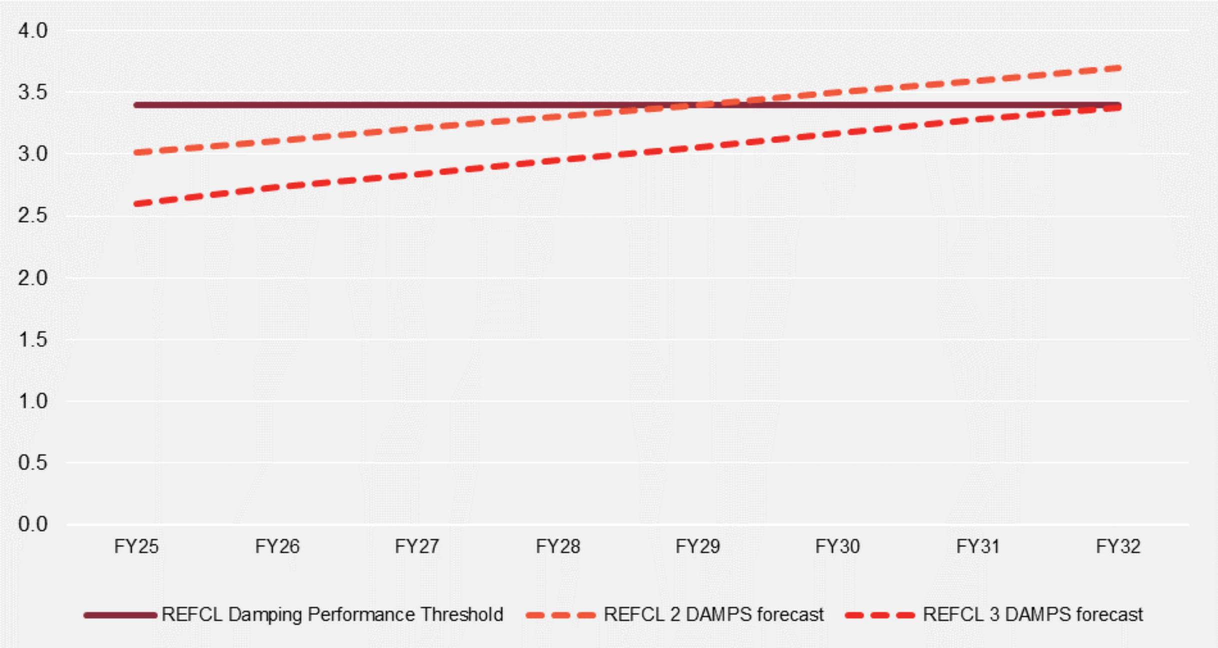
The zone substation in Eaglehawk (EHK) is supplied by sub-transmission lines from the BETS. It supplies Eaglehawk, Bridgewater, Inglewood, the northern part of Bendigo and the surrounding rural areas north of Bendigo.

The EHK zone substation is comprised of two 20/27MVA transformers operating at 66/22kV and two REFCLs. We forecast that a REFCL constraint is expected at EHK by 2028.

Site identified need

REFCL damping current limits will exceed the threshold limit for at EHK bus 2 in 2029 and bus 3 in 2032, as shown in figure 14 below.

FIGURE 14 EHK REFCL DAMPING CURRENT FORECAST



In order to maintain compliance with the Act, we must address the network damping current issues by 2029.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 15 EHK OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	There are no viable options available to transfer network due to a lack of REFCL transfer capacity in the neighbouring BGO and BETS zone substation networks. Therefore, this option is not technically feasible
Option 2 - isolating substations	Yes	This option involves electrically isolating sections of underground cable with high damping current in the EHK zone substation network from the REFCL networks at the zone substation. The isolation of network sections from the remainder of the EHK network does however limit operational flexibility. The cost of this option is: 14.2M (2026).
Option 3 - REFCL mini grid	Yes	This option involves the establishment of two REFCL mini grids and transferring selected sections of the network. The isolation of network sections from the remainder of the EHK network does however limit operational flexibility. A REFCL mini grid is proposed to be established on both bus 2 and bus 3 at EHK. The cost of this option is: 15.6M (2026).
Option 4 - adding a new REFCL	Yes	This option requires the installation of a third 66/22kV 25/33MVA transformer with associated switchgear and secondary system, the addition of a third REFCL. Existing network would then be transferred to the new transformer and associated REFCL. The cost of this option is: 12.8M (2026).
Option 5 - mini zone substation	No	This option has not been considered as the EHK zone substation can have an additional REFCL installed.
Option 6 - new zone substation	Yes	This option involves the establishment of a new substation in the region to transfer selected feeders to and reduce the damping current of the EHK network. This option includes 22kV distribution works to enable the load transfers from EHK and is considered feasible. The advantages of this option include improved operational flexibility, reliability and supply security. The cost of this option is: 50.1M (2026).

Preferred option

Option 5 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

TABLE 16 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	3.8	9.0	-	-	-	12.8

A.3.7 Gheringhap (GHP)

We note that Gheringhap (GHP) does not appear in Schedule 1 of the Regulations[14]. This substation was constructed in 2023 and supplies the network formerly supplied by the Corio and Geelong substation. The construction of the GHP substation was approved by ESV as providing the required capacity for the network supplied from the Geelong substation.

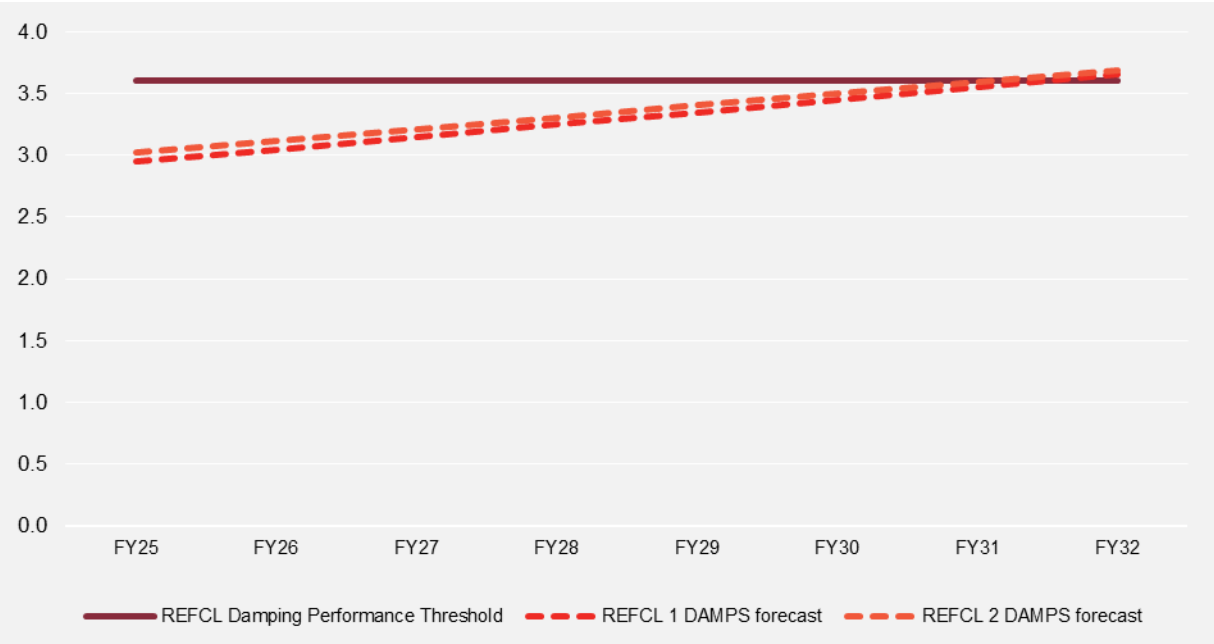
Gheringhap (GHP) zone substation is situated on the 66kV network in the Geelong region. It is supplied from the Geelong Terminal Station and also connected to the Corio zone substation via two 66kV lines. GHP has two 25/33MVA 66/22kV transformers supplying our 22kV network.

The zone substation and its two REFCLs were established in 2023 at GHP as part of the tranche three REFCL installation program. GHP substation doesn't have any points assigned to it as the substation was part of an exemption. The area was supplied by Geelong substation, which is a 4 point station, therefore 4 points are assumed.

Site identified need

REFCL damping current limits are forecast to be exceeded at GHP bus 2 in 2032, as shown in figure 15 below.

FIGURE 15 GHP REFCL 1 AND 2 DAMPING CURRENT FORECAST



In order to maintain compliance with the Act, we must address the network damping current issues by 2032.

14 Electricity Safety (Bushfire Mitigation) Regulations 2023 S.R. No. 40/2023 - Schedule 1—Zone substations

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 17 GHP OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	Yes	This option involves establishing a new GHP013 feeder. Network sections from bus 2 will then be transferred onto the new feeder. The cost of this option is: 3.7M (2026).
Option 2 - isolating substations	Yes	This option involves installing four new isolating substations (4 x 6MVA) to isolate the sections of high damping current on bus 2. The cost of this option is:7.1M (2026).
Option 3 - REFCL mini grid	Yes	This option involves establishing one REFCL mini grid on either the GHP011 or GHP021 feeders in the Meredith and Bannockburn areas respectively. The cost of this option is:15.6M (2026).
Option 4 - adding a new REFCL	Yes	This option involves establishing a new transformer and REFCL. GHP is a new zone substation where there is available land to install a third REFCL and power transformer. Transferring sections of the existing network onto the new REFCL will reduce the damping current on the existing REFCL. The cost of this option is:13.4M (2026).
Option 5 - mini zone substation	No	This option is similar to option 3 above. Since land is available for option 3 and option 4 is more costly than option 3, this option has not been considered.
Option 6 - new zone substation	Yes	While this option is feasible, this option will be a significantly higher cost than other options and so has not been progressed.

Preferred option

Option 1 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined in table 18.

TABLE 18 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	-	-	-	3.7	3.7

A.3.8 Gisborne (GSB)

Gisborne (GSB) zone substation is situated to the north-west of Melbourne. It is supplied from Keilor Terminal Station (KTS).

Work has commenced in the 2026–31 regulatory period to resolve a REFCL damping current constraint through the installation of a new REFCL and feeder rearrangement. This work is expected to continue into the 2026–31 regulatory period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined in table 19.

TABLE 19 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	9.3	-	-	-	-	9.3

A.3.9 Koroit (KRT)

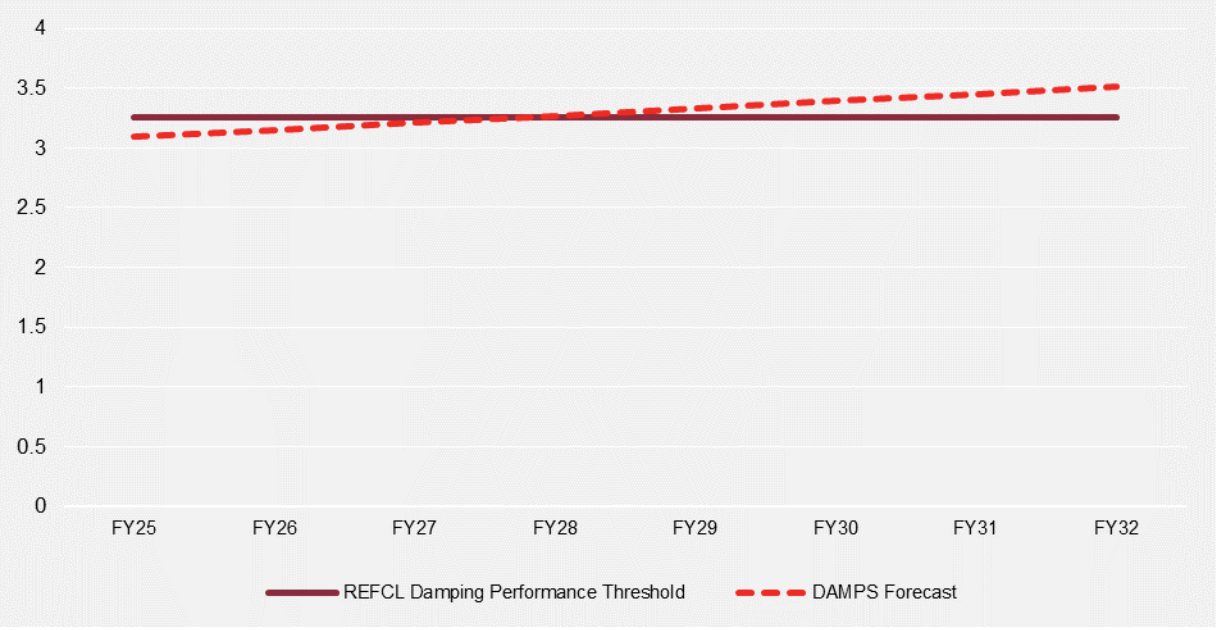
Koroit (KRT) zone substation is situated on the 66kV network in the Warrnambool region. It is supplied from the Terang Terminal Station and also connected to Warrnambool zone substation and Portland zone substation

The Koroit substation currently consists of three 13.5MVA 66/22kV transformers with one existing REFCL. KRT is a 2-point substation.

Site identified need

REFCL damping current limits are forecast to be exceeded at KRT in 2028, as shown in figure 16.

FIGURE 16 KRT REFCL 1 DAMPING CURRENT FORECAST



To maintain compliance the network damping current issues need to be addressed by 2028.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 20 KRT OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	The KRT substation network has no viable options for transferring network internally, as there is only one REFCL. While transfer of network the neighbouring Hamilton (HTN) zone substation network is technically possible, the high investment for long distance connections required to transfer between the networks is exorbitant. Therefore, this option is not feasible.
Option 2 - isolating substations	Yes	Installing isolation substations on sections of underground cable will therefore reduce the damping current on the KRT REFCL. The isolation of network sections from the remainder of the KRT network does however limit operational flexibility. The cost of this option is: 0.6M (2026).
Option 3 - REFCL mini grid	Yes	This option involves the establishment of one REFCL mini grid and transferring selected sections of the network to the isolated REFCL protected network. The cost of this option is: 7.8M (2026).
Option 4 - adding a new REFCL	Yes	This option requires the installation of an additional REFCL on and the transfer of existing network to the new REFCL. The cost of this option is: 5.6M (2026).
Option 5 - mini zone substation	No	This option has not been considered as an additional REFCL can be installed at KRT zone substation.
Option 6 - new zone substation	Yes	The establishment of a new substation in the region to transfer selected feeders to and reduce the damping current of the KRT network. This option includes 22kV distribution works to enable the load transfers from KRT and is considered feasible. The advantages of this option include improved operational flexibility, reliability and supply security. The cost of this option is: 50.1M (2026).

Preferred option

Option 2 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined in table 21.

TABLE 21 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	0.6	-	-	-	-	0.6

A.3.10 Torquay (TQY)

We note that Torquay (TQY) does not appear in Schedule 1 of the Regulations[15]. This substation was constructed in 2023 and supplies the network formerly supplied by the Geelong substation. The construction of the TQY substation was approved by ESV as providing the required capacity for the network supplied from the Geelong substation.

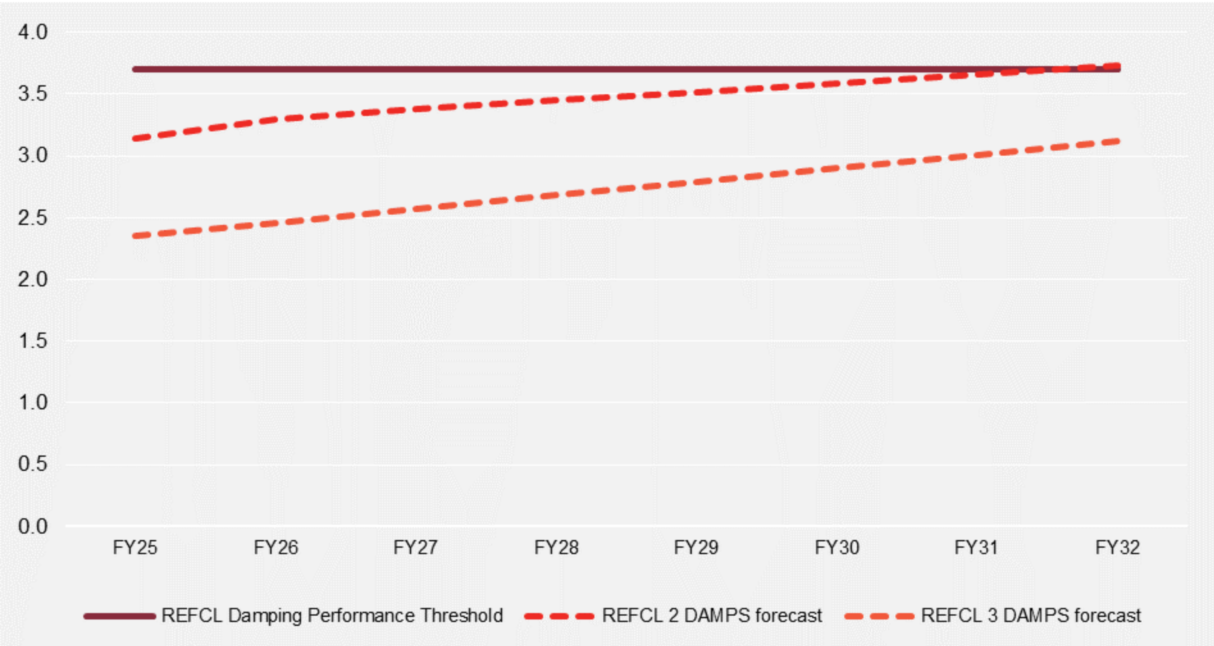
Torquay (TQY) is situated on the 66kV network and is supplied by Geelong Terminal Station. TQY has two 25/33MVA 66/22kV transformer supplying the 22kV network and our 22kV network. Two REFCLs were installed when the TQY zone substation was established in 2023 as part of the tranche three REFCL installation program.

TQY substation doesn't have any points assigned to it as the substation was part of an exemption. The area was supplied by Waurn Ponds substation, which is a 4 point station, therefore 4 points are assumed.

Site identified need

REFCL damping current limits are forecast to be exceeded at TQY bus 2 in 2031, as shown in figure 17 below.

FIGURE 17 TQY REFCL 2 AND 3 DAMPING CURRENT FORECAST



To maintain compliance, the network damping current issues must be addressed by 2031.

15 Electricity Safety (Bushfire Mitigation) Regulations 2023 S.R. No. 40/2023 - Schedule 1—Zone substations

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 22 TQY OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	Yes	This option involves establishing a new feeder supply sections from the bus 3 network. The cost of this option is:3.1M (2026).
Option 2 - isolating substations	No	There are no considerable sections of underground cable to isolate, as underground cable is in the network backbone, scattered throughout the network in small sections or already isolated.
Option 3 - REFCL mini grid	Yes	This option involves establishing one REFCL mini grid on the TQY021 feeder in the Paraparap area. The REFCL mini grid will isolate sections of the feeder rest of the TQY network, reducing damping current below the threshold on bus 2. The cost of this option is:7.8M (2026).
Option 4 - adding a new REFCL	Yes	This option involves establishing a new power transformer and REFCL. TQY is a new zone substation where there is available land to install a third REFCL, power transformer and transfer load to the new REFCL. The cost of this option is:13.4M (2026).
Option 5 - mini zone substation	No	This option is similar to option 4. Since this option is higher cost than option 3, this option has not been progressed.
Option 6 - new zone substation	Yes	This option involves establishing a new zone substation. The new zone substation will reduce the damping current on existing REFCL by transfer sections of the TQY network to the new zone substation. The cost of this option is:50.1M (2026).

Preferred option

Option 1 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined in table 23.

TABLE 23 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	-	-	3.1	-	3.1

A.3.11 Terang (TRG)

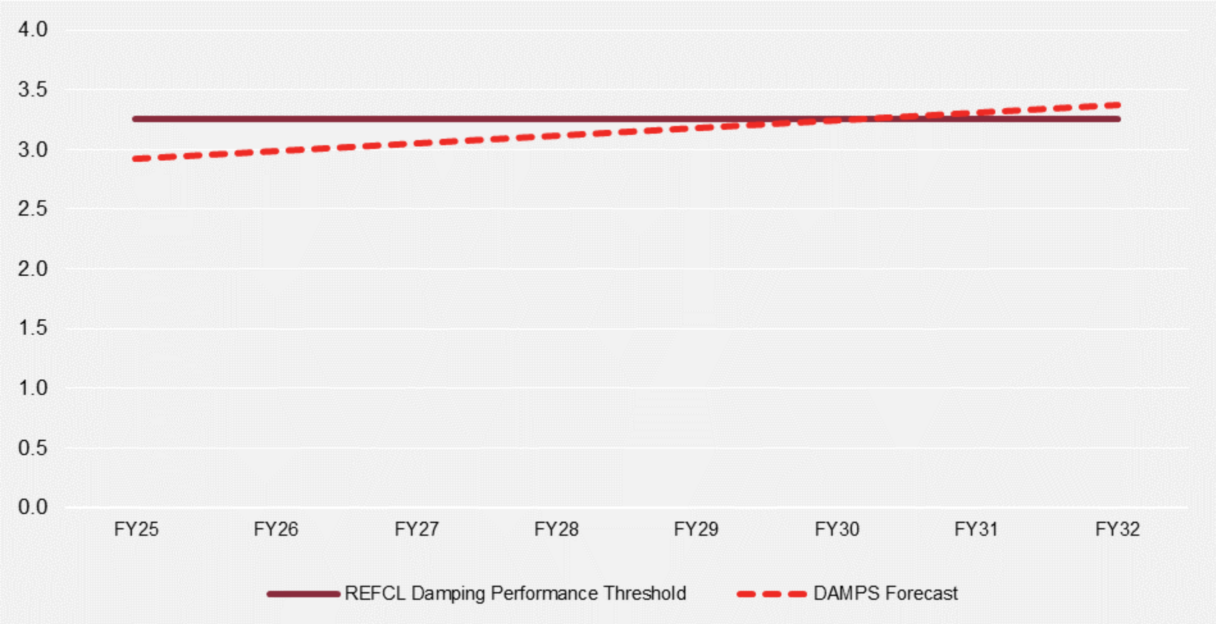
Terang (TRG) zone substation is situated on the 66kV network in the Western Districts region. It is supplied from the Terang Terminal Station and connected to Warrnambool zone substation and Portland zone substation.

The Terang zone substation currently consists of one 13.5MVA and one 25/33MVA 66/22kV transformer supplying our 22kV network. Due to the recent REFCL compliance requirements, there is one existing REFCL earthing unit. TRG is a 2-point substation.

Site identified need

REFCL damping current limits are forecast to be exceeded at TRG bus 1 in 2030, as shown in figure 18 below.

FIGURE 18 TRG REFCL 1 DAMPING CURRENT FORECAST



In order to maintain compliance with the Act, we must address the network damping current issues by 2030.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 24 TRG OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	This option is not considered feasible as there is only one REFCL at TRG and the neighbouring Camperdown (CDN) zone substation network does not have sufficient additional damping capacity to facilitate a transfer.
Option 2 - isolating substations	No	There are no considerable sections of underground cable to isolate to remove the constraint, as underground cable is in the network backbone, scattered throughout the network in small sections or already isolated.
Option 3 - REFCL mini grid	Yes	This option involves the establishment of one REFCL mini grid and transferring selected sections of the network to the isolated network. The cost of this option is:7.8M (2026).
Option 4 - adding a new REFCL	Yes	This option requires the installation of an additional REFCL at TRG and to transfer network to the new REFCL. The cost of this option is:5.6 (2026).
Option 5 - mini zone substation	No	This option not been considered as the TRG zone substation only has one REFCL currently installed.
Option 6 - new zone substation	Yes	This option involves the establishment of a new substation in the region to transfer selected feeders to and reduce the damping current of the TRG network. This option includes 22kV distribution works to enable the load transfers from TRG and is considered feasible. The advantages of this option include improved operational flexibility, reliability and supply security. The cost of this option is:50.1M (2026).

Preferred option

Option 4 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined in table 25.

TABLE 25 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	-	5.6	-	-	5.6

A.3.12 Winchelsea (WIN)

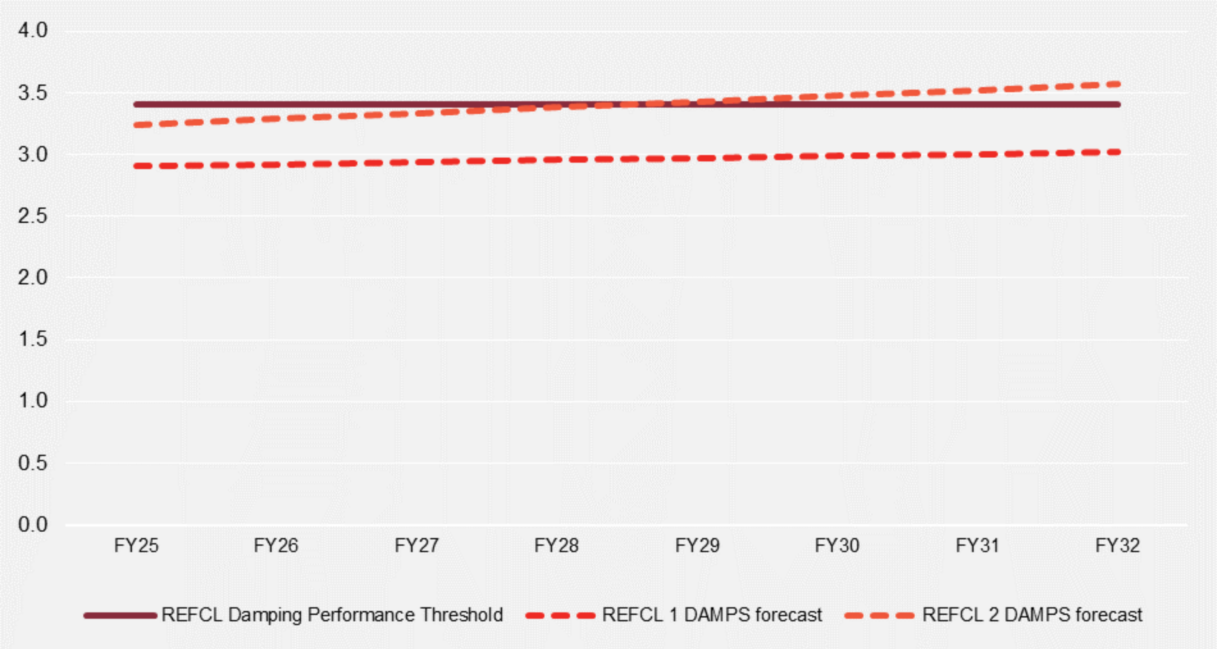
Winchelsea (WIN) zone substation is situated on the 66kV network in the Otways/Surf Coast region. It is supplied from the Gelong Terminal Station and also connected to the Mt Gellibrand and Blue Circle Geelong zone substations via 66kV lines.

The Winchelsea substation currently consists of one 7MVA and one 13.5MVA 66/22kV transformer supplying our 22kV network. Due to the recent REFCL compliance requirements, there are two existing REFCL earthing units for these transformers. WIN is a 5-point substation.

Site identified need

REFCL damping current limits are forecast to be exceeded at WIN bus 2 in 2029, as shown in figure 19 below.

FIGURE 19 WIN REFCL 1 AND 2 DAMPING CURRENT FORECAST



In order to maintain compliance with the Act, we must address the network damping current issues by 2029.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 26 WIN OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	No viable options for feeder reconfiguration due to the lack of available damping current transfer capacity to CLC.
Option 2 - isolating substations	Yes	This option involves electrically isolating sections of underground cable with high damping current in the WIN zone substation network from the REFCL networks at the zone substation. Three isolation substations are needed to isolate: • WIN022 - radial section of 13A where one (1) isolation substation is required • WIN023 - radial section of 10A where two (2) isolation substations are required to satisfy thermal capacity and reliability conditions. The cost of this option is: 5.3M (2026).
Option 3 - REFCL mini grid	Yes	This option involves establishing one REFCL mini in the Modewarre or Inverleigh area, which will isolate overhead lines with high damping current from the WIN network and reduce the damping current on existing REFCL below the threshold. The cost of this option is:7.8M (2026).
Option 4 - adding a new REFCL	No	Not suitable due to a lack of space to install new REFCL at the substation.
Option 5 - mini zone substation	Yes	This option involves extending the existing zone substation to establish a mini zone substation. This option is considered because here are two existing power transformers and REFCLs at the WIN zone substation, and land is available adjacent to the WIN zone substation. The cost of this option is:17.5M (2026).
Option 6 - new zone substation	Yes	This option involves establishing a new zone substation. The new zone substation will reduce the damping current on the existing REFCL by transferring sections of the BETS network to the new zone substation. The cost of this option is: 50.1M (2026).

Preferred option

Option 2 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined below.

TABLE 27 EXPENDITURE FORECAST FOR THE PREFERRED OPTION ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	2.1	3.2	-	-	-	5.3

A.3.13 Woodend (WND)

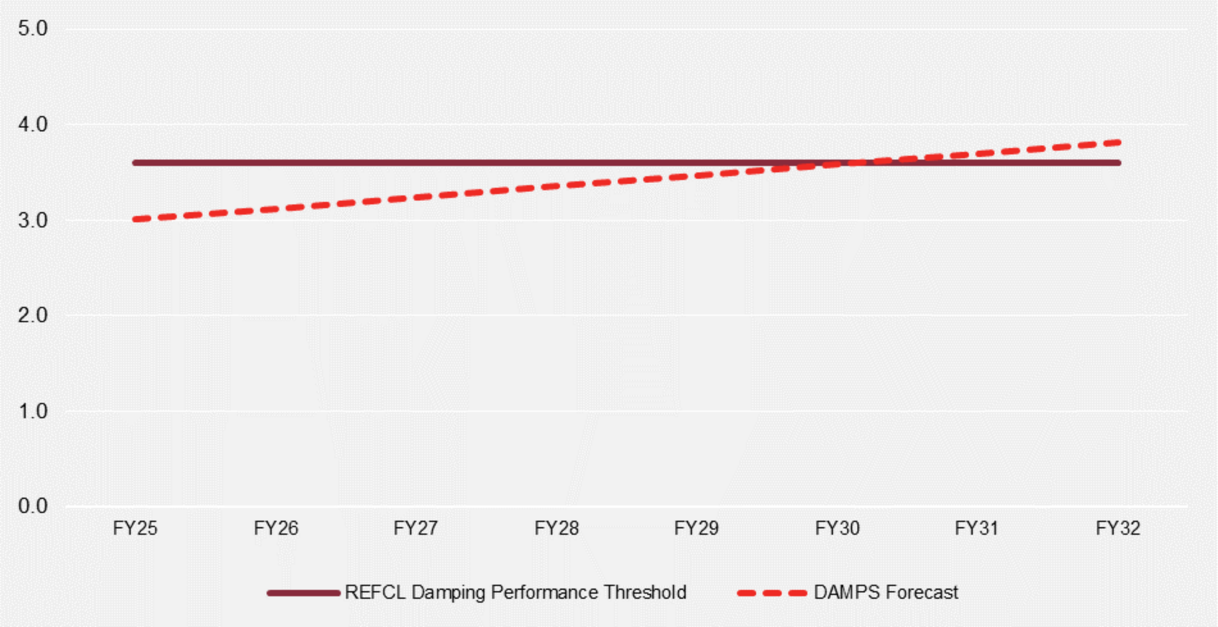
WND zone substation is situated on the 66kV network in the Macedon Ranges region. It is supplied from the Keilor Terminal Station and also connected to the Gisborne zone substation via two 66kV lines. WND has two 25/33MVA 66/22kV transformers supplying our 22kV network.

Two REFCLs were installed at WND as part of the tranche one REFCL installation program. WND is a 4-point substation.

Site identified need

REFCL damping current limits are forecast to be exceeded at WND bus 2 in 2030, as shown in figure 20 below.

FIGURE 20 WND REFCL 2 DAMPING CURRENT FORECAST



To maintain compliance, we must address the network damping current issues by 2031 on bus 2.

Options analysis

The following table provides an analysis of the options considered and whether they are feasible or not.

TABLE 28 WND OPTIONS ANALYSIS

OPTION	FEASIBLE	PROJECT ASSESSMENT
Option 1 - feeder reconfiguration	No	This option cannot address the network damping current issue as there is insufficient capability within the WND network to reduce the forecast growth in network damping current via feeder reconfiguration. Therefore, this option is technically infeasible.
Option 2 - isolating substations	No	There are no significant sections of underground cable to isolate from the REFCL networks at WND zone substation. Underground cables sections at WND zone substation either form part of feeder backbones, making isolation technically infeasible, or are scattered in smaller sections throughout the WND network.
Option 3 - REFCL mini grid	Yes	This option involves the establishment of two REFCL mini grids and transferring selected sections of the network to the two isolated networks, despite limiting operational flexibility. This option will also require new switchgear, land, fencing and HV and LV connections are needed for each of the REFCL mini grids. The cost of this option is:15.6M (2026).
Option 4 - adding a new REFCL	Yes	This option requires the installation of a third 66/22kV transformer, switchgear and secondary systems, the addition of a third associated REFCL system and the transfer of two feeders connected to existing transformers at the WND zone substation to the new transformer and associated REFCL. The cost of this option is: 12.6M (2026).
Option 5 - mini zone substation	No	This option is similar to option 4. Since this option is higher cost than option 3, this option has not been progressed.
Option 6 - new zone substation	Yes	This option involves the establishment of a new substation in the region to transfer selected feeders from the WND network. This option includes 22kV distribution works to enable the load transfers from WND and is considered feasible. The advantages of this option include improved operational flexibility, reliability and supply security. The cost of this option is: 50.1M (2026).

Preferred option

Option 4 is the preferred option because it is technically credible, meets the identified need to feasibly maintain compliance with obligations and is the least cost option across the long-term assessment period.

The expenditure forecast for this option of the 2026–31 regulatory period is outlined below.

TABLE 29 EXPENDITURE FORECAST FOR THE PREFERRED OPTION (2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Capital expenditure	-	0.6	2.4	9.6	-	12.6

A.3.14 Tranche one remediation works

As outlined in Section A.1.2, remediation works are proposed to bring all REFCL tranche one substations to the same standard of performance as more recent installations, particularly in relation to low voltage balancing capacitors and phase swapping. The scope will cover a review of tranche one REFCL substation phasing and capacitive imbalance followed by installation of capacitive balance units (CBUs) on the network. Based on previous experience, it is expected that the following remediation works will be required for each year in the 2026–31 regulatory period:

- 3 x new three phase CBUs installed to rectify imbalance and increase the number of balanced High Voltage (HV) switch zones.
- 2 x new single phase CBUs installed to balance high capacitance HV spurs.
- 5 x single phase spur rephasing.

Table 30 below shows the costs associated with the tranche one remediation works. These works are solely capital expenditure projects.

TABLE 30 CAPITAL EXPENDITURE FORECASTS FOR REMEDIATION WORKS ($M, 2026)

EXPENDITURE FORECAST	FY27	FY28	FY29	FY30	FY31	TOTAL
Remediation works	0.5	0.5	0.5	0.5	0.5	2.3

A.4 Recommendation

Based on the above analysis, we have identified several REFCL projects that are required to maintain compliance with our REFCL obligations. These projects are summarised in table 31 below.

TABLE 31 EXPENDITURE FORECASTS FOR PROPOSED PROJECTS ($M, 2026)

LOCATION	FY27	FY28	FY29	FY30	FY31	TOTAL
Ararat (ART)	0.3	-	-	-	-	**0.3**
Ballarat East (BAE): stage 2	0.7	13.2	0.7	-	-	**14.6**
Bendigo Terminal Station (BETS)	0.6	2.7	-	-	-	**3.3**
Bendigo (BGO)	-	-	0.6	2.5	10.2	**13.4**
Colac (CLC)	1.0	6.8	-	-	-	**7.8**
Eaglehawk (EHK)	3.8	9.0	-	-	-	**12.8**
Gheringhap (GHP)	-	-	-	-	3.7	**3.7**
Gisborne (GSB)	9.3	-	-	-	-	**9.3**
Koroit (KRT)	0.6	-	-	-	-	**0.6**
Terang (TRG)	-	-	5.6	-	-	**5.6**
Torquay (TQY)	-	-	-	3.1	-	**3.1**
Tranche one remediation	0.5	0.5	0.5	0.5	0.5	**2.3**
Winchelsea (WIN)	2.1	3.2	-	-	-	**5.3**
Woodend (WND)	-	0.6	2.4	9.6	-	**12.6**
Annual Total	**18.9**	**35.9**	**9.8**	**15.7**	**14.4**	**94.6**

B

MAINTAINING REFCL RELIABILITY

Powercor

B Maintaining REFCL reliability

REFCLs are a network protection device, normally installed in a zone substation. REFCLs significantly reduce the risk of fire starts arising from high voltage overhead powerline earth faults, such as a powerline that falls to the ground.

The installation of REFCLs at 22 of our zone substations was a mandated program and formed part of the Victorian Bushfire Royal Commission (VBRC) program of works.

B.1 Identified need

Upon detecting an earth fault, REFCLs operate almost instantaneously to isolate supply at the zone substation circuit breaker. That is, when an earth fault occurs on a powerline downstream of a traditional protection device (such as an ACR, remote-controlled switch, sectionaliser or fuse) the REFCL will always isolate the distribution feeder by operating the zone substation circuit breaker. This results in significantly larger number of customers being taken off supply than necessary, and is consistent with our experience to date.

We have successfully worked with a specialist vendor to develop a 'smart' ACR that is compatible with REFCLs to reduce the customer impact and are well progressed in the replacement of our traditional ACRs on REFCL protected networks. Notwithstanding this improvement, customers on REFCL protected networks still experience longer outages when compared with customers on non-REFCL protected networks, due to the degradation in earth fault detection capability of our remote-controlled switches and sectionalisers.

Remote-controlled switches and sectionalisers are installed along our feeders and used in conjunction with Fault Detection Isolation and Restoration (FDIR) schemes which automatically reconfigure the network quickly to minimise the number of customers off supply. On REFCL protected networks, the FDIR schemes do not function as intended due to the near instantaneous operation of the REFCL which isolates supply at the zone substation circuit breaker.

The identified need is to restore reliability for customers following the reduced automation capability of FDIR schemes on our REFCL protected networks, particularly associated with earth fault detection capability at our existing remote-controlled switch and sectionaliser sites.

B.2 Options considered

A number of potential options to address the loss of earth fault detection capability at the 149 remote-controlled switches installed on the REFCL protected networks have been considered.

Three credible options were progressed to option evaluation.

B.2.1 Option one: base case

Our base case option is to continue to use our existing fleet of remote-controlled switches and sectionalisers. This option is low cost, however the fault indication capability lost on installation of REFCL will continue to result in a poorer reliability experience for customers on REFCL protected networks.

Customer feedback during our stakeholder engagement was clear that customers are not willing to accept reductions in reliability performance, particularly as electrification is expected to increase their dependency on a reliable supply.

B.2.2 Option two: install REFCL compliant earth fault indicators

Option 2 involves the installation of A-Eberle EOR-3D fault indicators past each of the 149 existing remote-controlled switch and sectionaliser sites across all REFCL protected networks. This will restore the ability to detect earth faults on REFCL protected network and hence the FDIR functionality to automatically reconfigure the network quickly to minimise the number of customers off supply. This option results in reduced numbers of customers being taken off supply than necessary.

We have several trial sites installed across its REFCL network, with the trial sites demonstrating that the units provide the required earth fault detection capability

The cost of this option was based on historical installation costs of the A-Eberle EOR-3D fault indicator trial sites.

B.2.3 Option three: replace the existing fleet of remote-controlled switches and sectionalisers with REFCL compatible ACRs

Option 3 involves the replacement of the 149 existing remote-controlled switches and sectionalisers with NOJA OSM38/RC20 REFCL ACRs across all REFCL protected networks. We have utilised these ACRs to replace existing non compatible ACRs on its REFCL network and have successfully integrating them into our FDIR automation schemes. This option results in reduced numbers of customers being taken off supply than necessary and is equal in terms of benefit to option 2, the difference being this is a more expensive option.

The cost of this option was based on historical installation costs of the current REFCL ACR replacement program using the same NOJA OSM38/RC20 device and installation.

B.2.4 Option four: upgrade firmware on existing remote-controlled switches and sectionalisers

Option 4 involves upgrading to new firmware with the existing RL series switches/AVDC3 controllers to restore earth fault detection. This option is not credible as the vendor of the existing fleet of remote-controlled switches and sectionalisers has been unable to provide suitable firmware, or any firm commitment to do so.

B.3 Option evaluation

The credible options outlined above were evaluated in our attached cost-benefit analysis[16].

Both option two and three provide the required earth fault detection capability and equal benefit, however option three has a higher capital cost to implement at each location.

Table 32 shows the results of the option evaluation against the option one base case.

[16] PAL MOD 3.29 - REFCL reliability - Jan2025 - Public

TABLE 32 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COST ($M)	PV BENEFITS ($M)	NPV ($M)
2	Install A-Eberle EOR-3D fault indicators	(7.89)	19.98	12.09
3	Replace with NOJA OMS38/RC20 ACR	(12.57)	19.98	7.41

Sensitivity analysis was also used to test the robustness of the central scenario results. This included higher capital expenditure and lower benefits, and the combination thereof.

The results of the analysis show that option two was economic for all scenarios and remains as the preferred option.

B.4 Recommended option

The recommended option is option two to install 149 A-Eberle EOR-3D fault indicators past each of the remote-controlled switches and sectionalisers installed on all of our REFCL protected networks.

A summary of the proposed costs for the preferred option are set out in table 33.

TABLE 33 MAINTAINING RELIABILITY ON REFCL NETWORKS ($M, 2026)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Install A-Eberle EOR-3D fault indicators	-	4.15	4.15	4.15	-	12.48

C

MINIMISING BUSHFIRE RISKS IN THE HORSHAM SUPPLY AREA

C Minimising bushfire risks in the Horsham supply area

As outlined earlier, following the Black Saturday bushfires, the VBRC and subsequent Government response mandated the roll-out of REFCL technology at specified locations across Victoria. This included 22 sites across our network.

In its January 2024 consultation paper on REFCL operations, ESV stated that a distribution business does not meet their general duties by simply adhering to prescribed requirements. Rather, it noted that it is possible that additional deployment of REFCL technology, or extending the coverage of existing REFCLs, may be a practicable means by which relevant hazards and risks are mitigated, and therefore should be done to meet general duties obligations.

C.1 Identified need

Our bushfire risk model has identified that 22kV feeders from Horsham zone substation have the highest fire risk of all non-REFCL protected zone substations (shown in table 34).

This elevated risk level is particularly concerning given the potential for significant fire-related consequences in the surrounding areas. This means that if a fire is started from Horsham 22kV feeders during heightened fire conditions, it can result in significant damage including life loss.

Hence, there is a need to assess potential bushfire risk mitigation measures to reduce the fire risk associated with Horsham bare 22kV overhead lines, as far as practicable.

TABLE 34 TOP FIVE HIGHEST RISK ON NON-REFCL PROTECTED ZONE SUBSTATIONS

22KV FEEDERS RISK RANKING	NON REFCL ZONE SUBSTATION
1	Horsham (HSM)
2	Numurkah (NKA)
3	Bacchus Marsh (BMH)
4	Portland (PLD)
5	Cobden (COB)

C.2 Options considered

The below potential options have been considered to address the fire start risk by Horsham bare 22kV overhead lines. Only credible options were progressed to option evaluation.

C.2.1 Option one: base case

Our base case option is to maintain our existing maintenance program with no planned capital works. This option is low cost, but results in higher ongoing bushfire risk.

C.2.2 Option two: install single REFCL

This option entails installing a single REFCL at Horsham zone substation to cover all Horsham bare 22kV overhead lines. REFCLs reduce the likelihood of powerline related bushfires by detection of phase to ground faults and almost instantly reducing the voltage on the faulted line. Installation of a single REFCL will not achieve the required capacity requirements as per the mandated polyphase electric lines originating from a zone substation specified in Schedule 1 of the Electricity Safety (Bushfire Mitigation) Regulations 2023, however it will provide for an as far as practicable solution to reduce bushfire risk with 50 per cent fire risk reduction on Horsham bare 22kV overhead lines as compared with 54 per cent under a required capacity solution.

The cost of this option was based on historical installation costs of REFCLs and the necessary upgrade of the Horsham network.

C.2.3 Option three: install covered conductors on Horsham 22kV feeders

This option entails installing covered conductors on all Horsham bare 22kV overhead lines to minimise fire starts on Horsham 22kV feeders associated with asset failures (including pole top and conductors) and external impacts (including vegetation, animals and third-party contacts).

The cost of this option was based on historical installation costs of covered conductor.

C.2.4 Option four: install three REFCLs

This option entails installing three REFCLs (one for each zone substation transformer) at Horsham zone substation to cover all Horsham bare 22kV overhead lines. This meets the required capacity as required in the 2016 Amended Bushfire Mitigation Regulations and Electricity Safety (Bushfire Mitigation) Regulations 2023 for the mandated REFCL locations.

The cost of this option was based on historical installation costs of REFCLs and the upgrade of the Horsham network.

C.2.5 Option five: underground the overhead lines

This option considers undergrounding the Horsham 22kV overhead lines. This option has been deemed not credible as it is prohibitively expensive and provides only marginal benefits above covered conductor options. Accordingly, these were considered not credible and not evaluated further.

C.3 Option evaluation

The credible options described above were evaluated in our attached cost benefit analysis.[17] Table 35 shows the results of the option evaluation against the base case.

[17] PAL MOD 3.10 - Horsham REFCL - Jan2025 - Public

TABLE 35 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COST ($M)	PV BENEFITS ($M)	NPV ($M)
2	Install single REFCL	(11.7)	15.1	3.4
3	Install covered conductors on Horsham 22kV feeders	(149.9)	33.9	(116.0)
4	Install three REFCLs	(14.3)	16.2	1.9

Sensitivity analysis was also used to test the robustness of the central scenario results. This included higher capital expenditure and lower benefits, and the combination thereof.

The results of the analysis show that option two was economic for all scenarios and remains as the preferred option.

C.4 Recommended option

The recommended option is to install a single REFCL at Horsham zone substation, commencing in FY29. This option is the most economic option under the central scenario, and would minimise bushfire risks in the Horsham supply area as far as practicable for customers.

A summary of the proposed costs for the preferred option are set out in table 36.

TABLE 36 HORSHAM SINGLE REFCL EXPENDITURE ($M, 2026)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Minimising bushfire risks in the Horsham supply area	-	-	-	9.2	9.2	18.4

D

MINIMISING BUSHFIRE RISKS FROM BARE 22KV CONDUCTORS

D Minimising bushfire risks from bare 22kV conductors

Our network comprises over 35,606 km of bare 22kV conductor, with 79 per cent of our bare 22kV conductor lines traversing through electric line construction areas (ELCA), REFCL areas, and/or hazardous bushfire risk areas (HBRA).

D.1 Identified need

22kV lines are the leading cause of HV conductor fire incidents, accounting for 83 per cent of all HV conductor-related fires as shown in Table 37.

TABLE 37 HV CONDUCTOR FIRE STARTS BY VOLTAGE: 2012 - 2023

VOLTAGE	PERCENTAGE OF FIRE STARTS
22kV	83.0 %
12.7kV (SWER)	11.3 %
66kV	5.4 %
11kV	0.4 %

We have approximately 8,795km of bare 22kV overhead conductors located in Hazardous Bushfire Risk Areas (HBRA) that are not protected by REFCLs. This length excludes:

- bare 22kV conductors scheduled to be protected by new REFCLs in the 2026–31 regulatory period to ensure compliance
- bare 22kV conductors from the Horsham zone substation, which is proposed to be equipped with a new discretionary REFCL in the 2026–31 regulatory period.

The lack of REFCL protection on these bare 22kV conductors in HBRA represent a significant bushfire risk. The identified need, therefore, is to minimise as far as practicable the potential for fire starts associated with these conductor (including failures in these high-risk areas).

D.2 Options considered

The below options were considered to address the fire start risk due to bare non-REFCL protected HBRA 22kV conductor failures. Only credible options were progressed to option evaluation.

D.2.1 Option one: base case

Our base case option is to maintain our existing maintenance program with no planned capital works. This option is low cost, but results in higher ongoing bushfire risk.

D.2.2 Option two: targeted installation of covered conductor on bare 22kV non-REFCL lines in HBRA

This option entails installing covered conductor on 62km of bare non-REFCL protected 22kV conductors in HBRA to minimise sparking that could start fires in the event of an asset failure. These were the highest bushfire risk lines.

The lines were prioritised based on modelling individual sections of 22kV bare conductors, which highlighted those at high risk due to factors such as age, condition, and associated fire risks. The selection of specific lines was based on their demonstrated risk profiles, ensuring that the installation targets those segments that pose the greatest risk.

Based on this targeted approach, approximately 62 km of 22 kV covered conductor has been identified for installation in the highest-risk areas.

D.2.3 Option three: install EFD on all bare 22kV non-REFCL lines in HBRA

This option entails installing early fault detectors (EFDs) on all bare non-REFCL protected 22kV conductors in HBRA to identify potential 22kV line failures and enable a 'just in time' response to minimise the risk of fire starts. EFD is a technology that remotely detects and locates radio frequency (RF) signals emitted by incipient asset faults (i.e. a condition likely to develop into a fault or bushfire if left unremedied). EFDs provide notification of deteriorated or defective assets on our network which allows us to rectify the defect before it causes a fault or starts a fire.

The cost of EFDs are based on quoted supply costs from the vendor and installation costs from the EFD trial project.

D.2.4 Option four: targeted installation of EFD on bare 22kV non-REFCL lines in HBRA

This option is similar to option three above, but entails only installing EFDs on 1,500km, or approximately 20 per cent of the bare non-REFCL protected 22kV conductors in HBRA.

D.2.5 Option five: targeted installation of covered conductor and EFD on bare 22kV non-REFCL lines in HBRA

This option is a combination of options two and four, and entails installing:

- EFDs on 1,500km of bare non-REFCL protected 22kV lines
- covered conductor on 62km of bare non-REFCL protected 22kV lines that do not have EFD monitoring.

Under this option, covered conductor was identified as the most effective option for risk reduction. It was therefore considered first to prioritise line segments that pose the greatest risk.

EFD was considered as the next viable option for the remaining high-risk exposed sections of 22 kV conductors that would not be addressed by the covered conductor installations.

D.2.6 Option six: targeted undergrounding of bare 22kV non-REFCL lines in HBRA

Targeted undergrounding of the 62km of 22kV conductors identified in option two. This option, however, was not considered to be a credible option due to the prohibitive costs involved in undergrounding these distances.

D.3 Option evaluation

The credible options as set out above were evaluated in our attached cost benefit analysis.[18] Table 38 shows the results of the option evaluation against the base case.

TABLE 38 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COST	PV BENEFITS	NET BENEFITS
2	Targeted installation of covered conductor on bare 22kV non-REFCL lines in HBRA	(7.4)	13.5	6.1
3	Install EFD on all bare 22kV non-REFCL lines in HBRA	(68.1)	50.9	(17.2)
4	Targeted installation of EFD on bare 22kV non-REFCL lines in HBRA	(11.7)	10.3	(1.4)
5	Targeted installation of covered conductor and EFD on bare 22kV non-REFCL lines in HBRA	(19.1)	23.9	4.8

The preferred option is the targeted installation of covered conductor on 62km of bare non-REFCL protected 22kV conductors in HBRA (i.e. option two). This is the most economic option under the central scenario, and minimises risk as far as practicable for customers.

Sensitivity analysis was also used to test the robustness of the central scenario results. This included higher capital expenditure and lower benefits, and the combination thereof.

The results of the analysis show that option two was economic for all scenarios and remains as the preferred option.

D.4 Recommended option

The recommended option is the targeted installation of covered conductor on 62km of bare non-REFCL protected 22kV conductors in HBRA (Option 2).

A summary of the proposed costs for the preferred option are set out in table 39.

TABLE 39 TARGETED COVERED CONDUCTOR INSTALLATION EXPENDITURE ($M, 2026)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Minimising bushfire risks from bare non-REFCL protected 22kV conductors in HBRA	5.2	5.2	-	-	-	10.5

18 PAL MOD 4.17 - Minimise risk from 22kV conductor (bushfire) - Jan2025 - Public

E

MINIMISING BUSHFIRE RISKS FROM SWER LINES

Powercor

E Minimising bushfire risks from SWER lines

Our network comprises over 21,000km of single wire earth return (SWER) lines. Over 99 per cent of these lines traverse through electric line construction areas (ELCA), REFCL areas, and/or hazardous bushfire risk areas (HBRA).

E.1 Identified need

SWER lines are the second highest cause of fire starts among HV conductors. The identified need, therefore, is to minimise as far as practicable the fire risk of our SWER network in our highest bushfire risk areas.

E.2 Options considered

The options considered to address the identified need are set out below, including a base case scenario. As SWER networks are not compatible with REFCL technology, the options to minimise the fire risk of SWER lines include covered conductor and early fault detection (EFD).

E.2.1 Option one: base case

Our base case option is to maintain our existing maintenance program with no planned capital works. This option is low cost, but results in higher ongoing bushfire risk.

E.2.2 Option two: install covered conductor on targeted SWER lines in ELCA, REFCL areas and HBRA

Installing covered conductor on SWER lines minimises sparking that could start fires should the conductor fail or if contact is made with the conductor (e.g. tree branch contacts with overhead line). Our bushfire risk model assumes covered conductor is effective at mitigating 91 per cent of this risk.

Installing covered conductor on all SWER lines, however, would be prohibitively expensive and accordingly, was not considered a credible option. Instead, this option considers a targeted program to install covered conductor on approximately 76km of high-risk SWER lines in ELCA, REFCL areas and HBRA.

The targeted volume of 76 km was determined by modelling individual SWER sections. Factors considered included the age and condition of the conductors, and associated fire risks.

The selection of specific lines was based on their demonstrated risk profiles, ensuring that the installation targets those segments that pose the greatest risk. This method aims to significantly reduce the ignition risk posed by these conductors while ensuring a positive net benefit.

The cost of this option was based on historical installation costs of covered conductor.

E.2.3 Option three: install EFD on all SWER lines in ELCA, REFCL areas and HBRA

EFD is a technology that remotely detects and locates radio frequency (RF) signals emitted by incipient asset faults (i.e. a condition likely to develop into a fault or bushfire if left unremedied). EFDs provide notification of deteriorated or defective assets on our network which allows us to rectify the defect before it causes a fault or starts a fire.

Installing EFDs on SWER lines can detect failing electrical components for replacement before they fail, such as cracked insulators or broken conductor strands. Hence, EFDs can enable a timely response to rectify defects which can reduce the likelihood of fire starts.

We currently have 230 EFDs installed on our network under a trial commenced in 2018, covering approximately 800 kms. These trial devices vary in device generation, with the majority (150 devices) being the SWER FireSafe generation installed in 2022.

The trial has informed key assumptions for the business case. Specifically, it supports the assumption in our bushfire risk model that EFD is 33 per cent effective at mitigating this risk. This is because most of the fire start faults are instantaneous (e.g. windblown vegetation contact with bare SWER line causing conductor failure and resulting in fire start). These kinds of events will be identified by the EFD but will not assist in minimising fire starts under these scenarios.

This option considers extending our EFD coverage to all SWER lines, excluding those proposed to otherwise be replaced or upgraded in the 2026–31 regulatory period.

The costs of EFD are based on quoted supply costs from the vendor and installation costs from the EFD trial project.

E.2.4 Option four: install EFD on targeted SWER lines in ELCA, REFCL areas and HBRA

Rather than installing EFD on all SWER lines in ELCA, REFCL areas and HBRA, this option considers a lower cost, targeted installation covering 2,107km of the highest risk SWER sections. These sections were selected based on economic analysis.

E.2.5 Option five: install covered conductor and EFD on targeted SWER lines in ELCA, REFCL areas and HBRA

This option is a combination of option two and four above, comprising the installation of EFD on 2,107km of SWER and covered conductor on 76km of SWER.

The method for identifying SWER lines targeted for either covered conductor or EFD was based on the following approach:

- primary mitigation strategy—covered conductor was identified as the most effective option for risk reduction. It was prioritised based on modelling individual sections of SWER bare conductors, which highlighted those at high risk due to factors such as age, condition, and associated fire risks. The selection of specific lines was based on their demonstrated risk profiles, ensuring that the installation targets those segments that pose the greatest risk
- complementing risk management approach—EFD was considered as the next viable option for the remaining high-risk exposed sections of SWER conductors that would not be addressed by the installation of covered conductor.

This approach aims to reduce the ignition risk posed by SWER conductors while ensuring a positive net benefit.

E.2.6 Option six: undergrounding SWER lines

Our options assessment also considered undergrounding all SWER lines. Undergrounding solutions, however, would be prohibitively expensive and provide only marginal benefits above covered conductor options.

Accordingly, these were not considered credible (and hence, not costed and evaluated).

E.3 Option evaluation

The credible options outlined above were evaluated in our attached cost-benefit analysis.[19]

The benefits case for each option were determined using our bushfire risk model, and the results of the option evaluation against the base case are shown in table 40.

TABLE 40 OPTION EVALUATION RESULT ($M, 2026)

OPTION		PV COST	PV BENEFITS	NET BENEFITS
2	Targeted installation of covered conductor on SWER lines in ELCA, REFCL areas and HBRA	-4.2	5.3	1.1
3	Install EFD on all SWER lines in ELCA, REFCL areas and HBRA	-115.2	62.9	-52.3
4	Targeted installation of EFD on SWER lines in ELCA, REFCL areas and HBRA	-11.4	12.0	0.6
5	Targeted installation of covered conductor and EFD on SWER lines in ELCA, REFCL areas and HBRA	-15.6	17.3	1.7

The preferred option is option five—the targeted installation of covered conductor and EFD on SWER lines in ELCA, REFCL areas and HBRA. This option minimises risks as far as practicable and provides the highest net benefit to customers.

Sensitivity analysis was also undertaken to test the robustness of option evaluation. This included higher capital expenditure and lower benefits, and the combination thereof.

The results of the analysis show that targeted installation of covered conductor on SWER lines in ELCA, REFCL areas and HBRA remains economic under most sensitivities, but the benefits case associated with the targeted installation of EFD becomes marginally uneconomic if costs and benefits vary materially. In considering the sensitivity on EFD, however, we note that several other benefits have not been fully quantified—for example:

- improved planning and informed decision making when prioritising SWER maintenance activities
- proactive identification of faults, removing the safety risk associated with community members, livestock and any third parties then being subjected to a hazardous environment which is created once a fault has occurred.

E.4 Recommended option

Our customers have expressed strong views that safety, including minimising bushfire risks, are non-negotiable. As outlined previously, this includes our customer values research and the research undertaken by Monash University as part of their Future Home Demand study.[20] This study found that safety was a part of most respondents' primary household value set.

---

[19] PAL MOD 3.23 - Minimise bushfire risk from SWER - Jan2025 - Public

[20] PAL ATT SE.10 – Monash University - Future home demand – Jul2023 – Public.

On this basis, and consistent with our AFAP obligations, we maintain that greatest weight should be placed on the underlying central sensitivity scenario, with option five being the recommended solution.

A summary of the proposed capital expenditure for the preferred option is set out in table 41.

TABLE 41 TARGETED INSTALLATION OF COVERED CONDUCTOR AND EFD ON SWER LINES IN ELCA, REFCL AREAS AND HBRA ($M, 2026)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Minimising bushfire risks from bare non-REFCL protected 22kV conductors in HBRA	6.5	6.5	-	-	-	13.0

F

MINIMISING BUSHFIRE RISKS FROM HV WOOD CROSSARMS

F Minimising bushfire risks from HV wood crossarms

Our current asset management practice includes the replacement of deteriorated HV wood crossarms with steel equivalents as part of our ongoing cross-arm and pole replacement programs. These programs, however, are not expected to replace all HV wood crossarms by the end of the 2026–31 regulatory period.

F.1 Identified need

Insulator leakage is the leading cause of crossarm related fire starts. To address this risk effectively, replacing wood crossarms with non-combustible steel crossarms along with new insulators represents a significant opportunity to reduce fire start risks, particularly in HBRA.

Hence, the identified need is minimise as far as practicable, the fire risks associated with our remaining HV wood crossarms.

F.2 Options considered

Two potential options to minimise fire start risks from HV wood crossarms were identified, and outlined below. Alternative options—such as undergrounding overhead lines—were not considered credible due to prohibitive costs.

F.2.1 Option one: base case

This option would maintain our existing wood crossarms and pole replacement programs with no additional proactive crossarm replacements.

Based on existing replacement levels today, this will result in an estimated 4,761 HV wood crossarms in HBRA remaining in service at the end of the 2026–31 regulatory period. These volumes, however, would be completely removed from our network by approximately FY34.

F.2.2 Option two: accelerated replacement with steel crossarms

Option two entails a program of works to accelerate the replacement of HBRA HV wood crossarms with steel equivalents, such that all these crossarms are removed from our network by the end of the 2026–31 regulatory period. In effect, this program brings forward the replacement of these assets by around three-years.

The benefits of this program are the avoided bushfire risk associated with earlier removal of these assets. These benefits are valued using our bushfire model, as described previously in this document.

F.3 Option evaluation

The credible options outlined above were evaluated in our attached cost-benefit analysis.[21] Table 42 shows the results of the option evaluation against the base case.

[21] PAL MOD 4.16 - HV wooden crossarms (bushfire) - Jan2025 - Public

TABLE 42 OPTION EVALUATION RESULT ($M, 2026)

DESCRIPTION	PV COST ($M)	PV BENEFITS ($M)	NPV ($M)
Accelerated replacement with steel crossarms	(2.8)	12.7	9.9

The preferred option is to accelerate the replacement of HV wood crossarms in HBRA with steel equivalents, such that all remaining HV wood crossarms are removed by the end of the 2026–31 regulatory period (i.e. option two). This option is economic under the central scenario and minimises bushfire risk as far as practicable.

Sensitivity analysis was also used to test the robustness of the central scenario results. This included higher capital expenditure and lower benefits, and the combination thereof.

The results of the analysis show that option two was economic for all scenarios and remains as the preferred option.

F.4 Recommended option

As above, the recommended option is to accelerate the replacement of HV wood crossarms in HBRA. A summary of the proposed (incremental) costs for the preferred option are set out in table 43.

TABLE 43 PROACTIVE REPLACEMENT OF HBRA HV WOODEN CROSSARMS ($M, 2026)

DESCRIPTION	FY27	FY28	FY29	FY30	FY31	TOTAL
Accelerated replacement with steel crossarms	4.8	4.8	4.8	4.8	4.8	23.9

For further information visit:

Powercor.com.au

CitiPower and Powercor Australia

CitiPower and Powercor Australia

CitiPower and Powercor Australia