AusNet Electricity Services Pty Ltd

Delivering Tranche Three of the Rapid Earth Fault Current Limiter (REFCL) Program

Reliability Corrective Action

RIT-D Draft Project Assessment Report

March 2021

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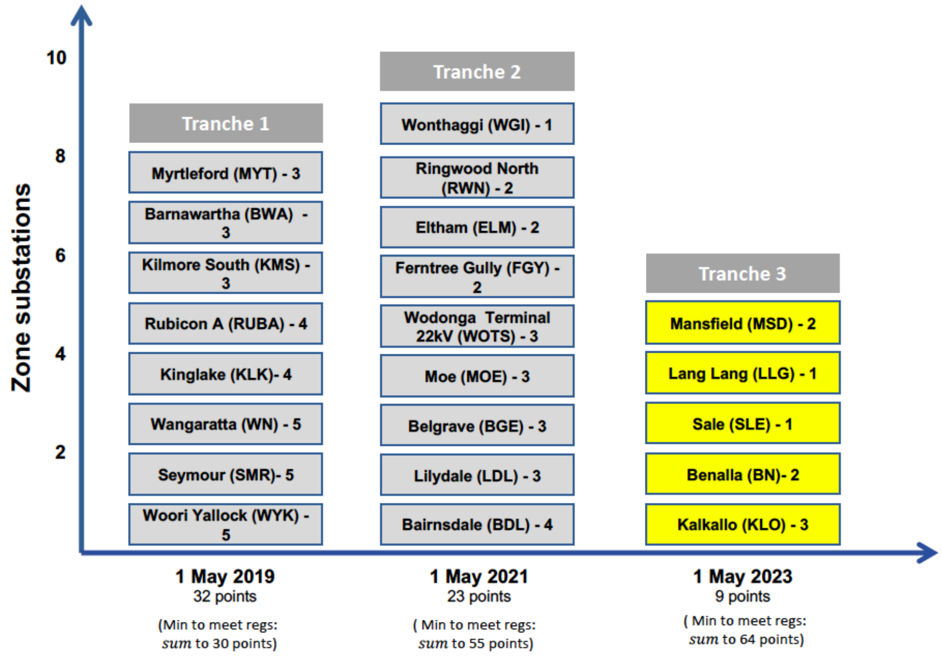
1 Introduction

1.1 Overview

AusNet Services is subject to bushfire mitigation regulations that set highly challenging performance standards at 22 zone substations. These standards can only be met by installing Rapid Earth Fault Current Limiters (REFCLs), which have not previously been implemented for bushfire reduction anywhere in the world. In addition, the project is time-critical because the regulations set establishment dates, and the Government has reinforced the importance of timely delivery by introducing significant financial penalties if the regulations are not met.

As presented in Figure 1 below, our REFCL program is being deployed in three tranches based on a points system that, by assigning more points to higher risk areas, aims to prioritise zone substations where fire mitigation measures would provide the greatest benefit.

Figure 1: REFCL location, points and implementation timing[1]



Tranche three of the REFCL program is the final tranche to meet our compliance obligations in relation to the specified zone substations by 1 May 2023. This Tranche is subject to the regulatory investment test for distribution (RIT-D), an economic cost-benefit test used to assess and rank potential investments capable of meeting an identified need.[2] The purpose of the RIT-D is to identify credible options to maximise the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market.

Under clause 5.17.4(c) of the National Electricity Rules (NER), AusNet Services determined that there are no credible non-network options that could satisfy our REFCL Tranche three obligations. We therefore issued a notice of determination in accordance with clause 5.17.4(d) of the NER. The next stage of the RIT-D process is the publication of this Draft Project Assessment Report (DPAR), which explains why the preferred network option meets the requirements of the RIT-D.

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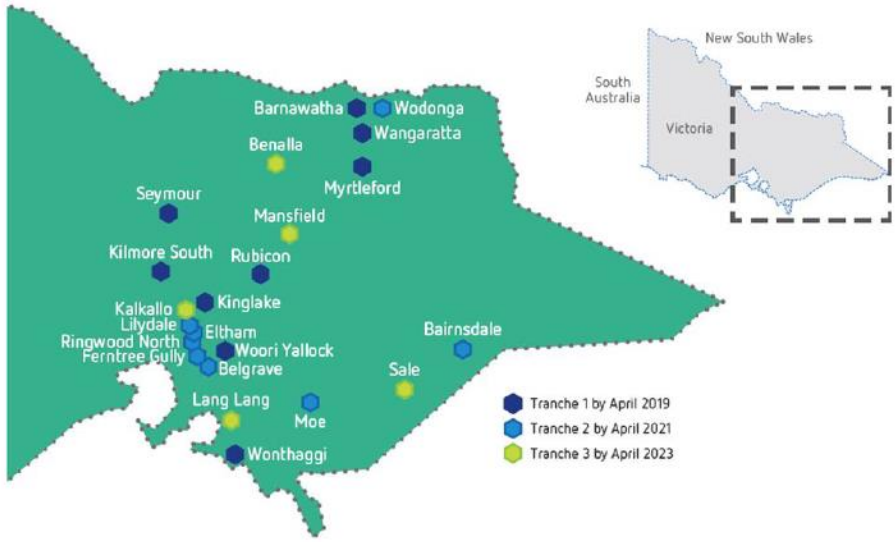
1 This figure is reproduced from the Tranche three Contingent Project Application submitted to the AER. The actual compliance dates and composition of the tranches have been varied from those shown to enable technical and cultural heritage issues to be addressed. These changes are not relevant to this DPAR.

2 Tranche 2 of the REFCL program was subject to transitional provisions under clause 11.99.6 of the National Electricity Rules that excluded this tranche from the application of the RIT-D.

This DPAR complies with the requirements of Clause 5.17.4(j) of the NER, as detailed in section 7 of this document.

Figure 2: Overview of the REFCL program[3]



It should be noted that Tranche three of the REFCL program has been subject to a separate regulatory process conducted by the Australian Energy Regulator (AER), following the submission of our Contingent Project Application in May 2019.[4] The purpose of that application was to obtain an amendment to the AER's regulatory determination for our distribution business to provide a revenue allowance for Tranche three of the REFCL program. The Contingent Project Application therefore provided a detailed explanation of the measures we have taken to ensure the project scope and costings comply with the prudency and efficiency requirements in the NER.

The AER's final decision on our Contingent Project Application for Tranche three program concluded the total capital expenditure reasonably required to complete the project is $94.4 million. This decision reduced our proposed capital expenditure by 10.5 per cent, which reflected the AER's decision to reject a second Kalkallo substation. Subsequently, we have sought funding for an amended project scope for Kalkallo substation, which is currently being considered by the AER in its assessment of our regulatory proposal for the 2021-26 period and is reflected in this DPAR.

While the purpose and scope of this DPAR differs from the earlier contingent project process, the information prepared in our Contingent Project Application and the AER's subsequent determination remains relevant. Where appropriate, therefore, this DPAR draws on the information prepared in our Contingent Project Application for Tranche three of the REFCL program.

1.2 Consultation

In accordance with Clause 5.17.4(k) of the NER we request submissions on the matters set out in this DPAR. Notification of this request for submissions will also be provided to Registered Participants, AEMO, non-network providers, interested parties and persons on our demand side engagement register as required by the NER.

Submission in response to this report should be sent to ritdconsultations@ausnetservices.com.au by Tuesday 27 April 2021 and telephone enquiries can be directed to Tom Langstaff on (03) 9695 6859.

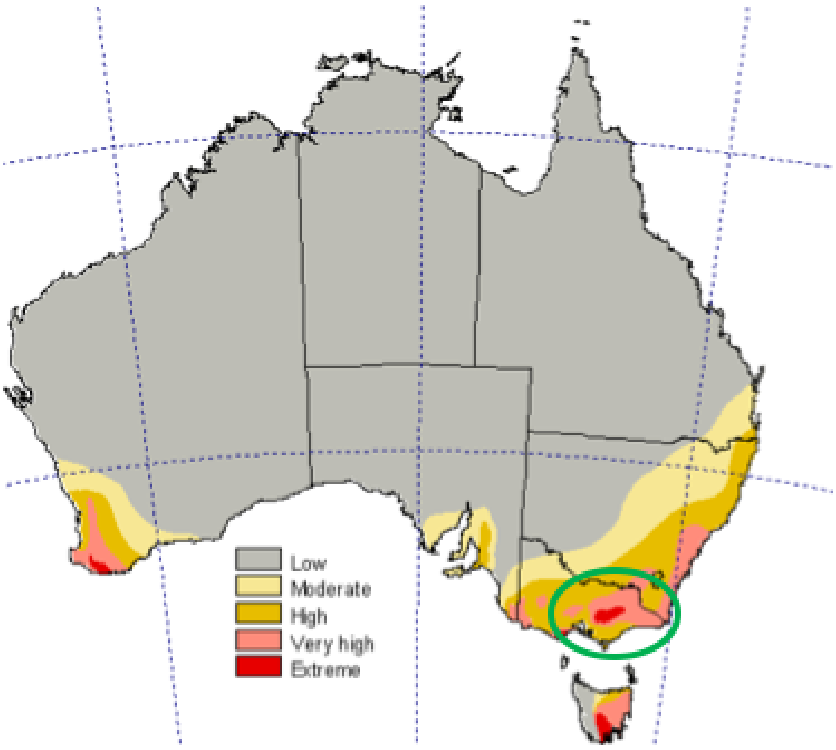
3 As per footnote 1, this figure is reproduced from Tranche three Contingent Project Application submitted to the AER. As already noted, the actual compliance dates and composition of the tranches have been varied from those shown..

4 AusNet Electricity Services Pty Ltd, Contingent Project Application – Tranche 3, Bushfire Mitigation, 31 May 2019.

2 Identified need for the investment

Our electricity distribution network operates in a geographical location which is exposed to a unique level of extreme bushfire risk. These conditions warrant significant bushfire risk mitigation measures, which require additional network investment.

Figure 3: AusNet Services' extreme bushfire risk



The 2009 Victorian Bushfire Royal Commission made several recommendations to avoid fires initiated from distribution electricity networks. Recommendation 27 called for new technology that greatly reduced bushfire risk being applied to all overhead conductors (SWER and 22kV powerlines) in high bushfire risk areas. The Royal Commission also suggested that an expert taskforce (the Powerline Bushfire Safety Taskforce) be established to advise on the best means of achieving the intent of this recommendation.

This advice was provided to the Victorian Government in September 2011. The Taskforce's report indicated that the optimal means of reducing bushfire risk from SWER and 22kV powerlines was a mixture of powerline replacement, automatic circuit reclosers (ACRs) on SWER lines and the selective installation of Rapid Earth Fault Current Limiters (REFCLs). The Taskforce also identified the need for further research and development, particularly as REFCLs had not been used for bushfire suppression previously.

In December 2011, the Government accepted the Taskforce's recommendations, and established the Powerline Bushfire Safety Program to determine the optimal method for deploying REFCLs for bushfire prevention. Following the completion of this research program, the Government introduced the *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016* in May 2016 which amended the *Electricity Safety (Bushfire Mitigation) Regulations 2013* (the Regulations).

The Regulations require that each polyphase electric line originating from a list of selected zone substations must have the following capability, which is defined as 'Required Capacity', in the event of a phase to ground fault:

> *To reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to —*
>
> *(i) 1900 volts within 85 milliseconds; and*

(ii) 750 volts within 500 milliseconds; and

(iii) 250 volts within 2 seconds. [5]

For AusNet Services, the Regulations require each polyphase electric line originating from 22 selected zone substations to comply with the mandated performance standards by 1 May 2023. The Victorian Government has also introduced legislation that applies financial penalties if service performance in accordance with the timetable is not met. Tranche three is the final tranche of our REFCL program, which is targeted to achieve 'Required Capacity' at all remaining zone substations by 1 May 2023.

> The identified need is to comply with the Electricity Safety (Bushfire Mitigation) Regulations 2013, to achieve 'Required Capacity' at the Tranche three zone substations (Mansfield; Sale; Lang Lang; Benalla; and Kalkallo) by 1 May 2023.

The NER defines a reliability corrective action as an investment by a Distribution Network Service Provider in respect of its network for the purpose of meeting the service standards linked to the technical requirements of NER schedule 5.1 or an applicable regulatory instrument. In relation to Tranche three of the REFCL program, AusNet Services classifies the identified need as 'reliability corrective action' as the Regulations require network investment in order to comply with the Required Capacity at the remaining REFCL zone substations, and the 22 kV networks they supply.

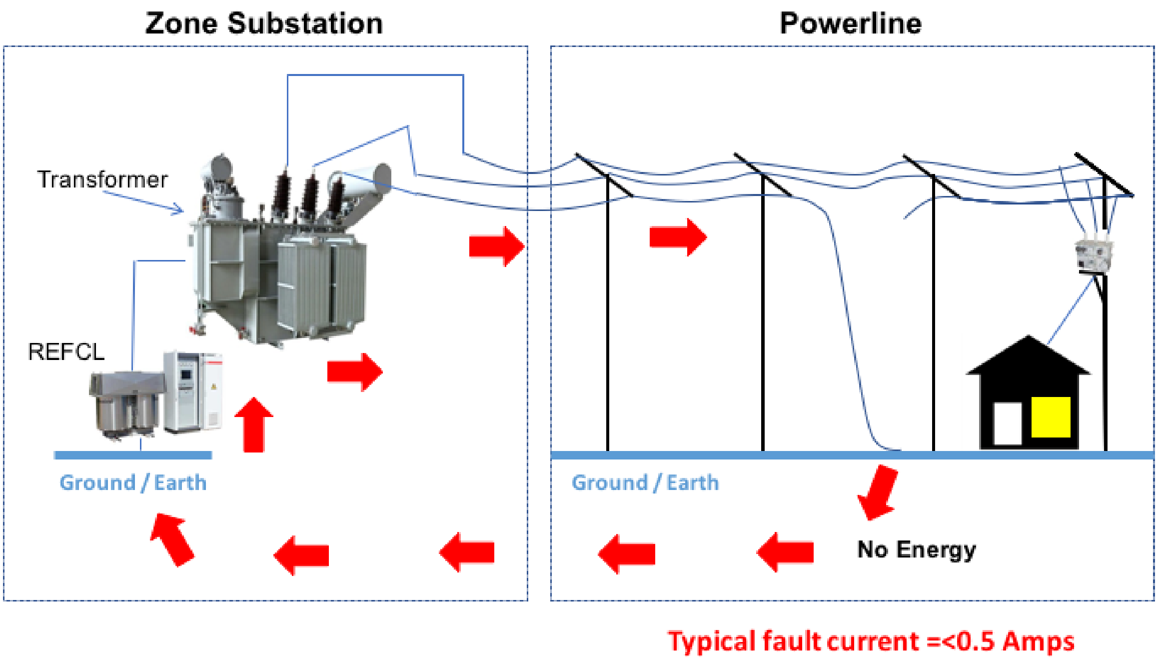
For a reliability corrective action, the preferred option may result in a negative net economic benefit, as outlined in clause 5.17.1(b) of the NER. As explained in further detail in the next section, however, the Victorian Government's Regulatory Impact Statement included a detailed cost-benefit analysis which showed the bushfire risk reduction benefits of deploying REFCLs outweighed the expected costs. For the purpose of this DPAR, we have not quantified the fire reduction benefits underpinning the decision to implement the Regulations. Instead, we have identified the lowest cost solution to achieve compliance at each zone substation. This approach ensures the net benefit from Tranche three REFCL implementation is maximised.

5 Other performance requirements are also specified in the definition of 'required capacity' in the Electricity Safety (Bushfire Mitigation) Regulations 2013.

3 What is REFCL technology?

A REFCL is a type of electricity network protection device, which is designed to minimise the fault current (energy) dissipated from phase to earth (wire to ground) faults on the 22kV network in order to reduce the risk of fire ignition associated with network incidents, as shown below.

Figure 4: How does REFCL technology work?



There are various types of technology that fall under the REFCL umbrella, however the only type of REFCL currently considered suitable by the Victorian Electric Supply Industry (VESI) for bushfire safety are the Ground Fault Neutraliser (GFN), a proprietary product by Swedish Neutral and the Siemens Trench ARCC ® (Advanced Residual Current Compensation) system. Presently, these REFCLs are the only devices that can meet the performance criteria of the Regulations.

REFCL technology operating at the required performance standard will minimise the risk of fire ignition associated with phase to ground faults on days of heightened fire danger, such as those experienced on Ash Wednesday and Black Saturday. Based upon a sample period of network fault data, analysis undertaken by the Government and CSIRO predict network fire related incidents associated with the nominated zone substations may be reduced by between 50-55%.

A REFCL operates when a single phase-to-earth fault occurs. Its operation causes the phase to ground voltage of the faulted phase to be reduced to near earth potential (zero volts), thereby working to eliminate the flow of fault current. To achieve this outcome, the REFCL is tuned to the capacitance of the electrical network and a current injected into the transformer neutral that cancels the residual active fault current. This compensation results in phase to ground voltage on the faulted phase reducing to near 0 volts and the fault current being reduced to a very low value. The healthy phases could rise from 12.7 kilo Volts (kV) to 24.2kV, being 22kV plus 10 per cent.

While the REFCL is compensating for a fault, the healthy phases remain energised and customers remain on supply. However, there remains a risk the energised phases may be in an unsafe condition depending on the nature of the network fault. Accordingly, a maximum compensating period applies under the Regulations.

The GFN technology is made up of four main components:

- Arc Suppression Coil (**ASC**) – also known as a large inductor, which compensates for the leakage current during an earth fault.

- Residual Current Compensator (**RCC**), also referred to as the inverter, which is located in the zone substation control building or switchroom. It is used to reduce fault current by compensating for the active current during an earth fault.
- Control Cubicles (**CC**), which controls the equipment.
- Grid Balancing Cabinet (**GRBC**), which fine tunes capacitive imbalance from the zone substation to achieve better detection sensitivity.

Figure 5: Four components to GFN technology

Arc Suppression Coil/ Inductor

Residual Current Compensator/ Inverter

Control Panel

Grid Balancing Cabinet

The REFCL ARCC technology is made up of three main components:

- Arc Suppression Coil (ASC) – also known as a large inductor, which compensates for the leakage current during an earth fault.
- ARCC Inverter which is located in the zone substation control building or switchroom. It is used to reduce fault current by compensating for the active current during an earth fault.
- Control device, EFD 500 cc which controls the equipment.

Figure 6: Three components to ARCC technology

Arc suppression coil tune-able inductance

ARCC inverter

Control device, EFD 500 cc

As explained in further detail in later sections of this DPAR, the scope of the required works is much broader than the components described above.

This is because the installation of REFCLs requires a paradigm shift in how our network is designed, operated and maintained. As such, all components of the affected 22kV distribution network need to be reviewed to ensure the REFCL-enabled network can operate safely and reliably.

4 Screening for credible non-network options

The purpose of the RIT-D is to identify the credible option for addressing an identified need that maximises the net market benefit. In accordance with this requirement, AusNet Services has determined there are no non-network options in relation to the Tranche three REFCL program. Our reasoning for concluding there are no credible non-network options are set out in our notice of determination under clause 5.17.4(d) of the NER.

In summary we determined that:

- The installation of REFCLs is the only technically feasible solution currently available that is capable of satisfying the performance requirements specified in the Regulations.
- The proposed capital works on AusNet Services' distribution network (and associated operating expenditure) are required to ensure REFCL operation does not compromise the safety and reliability of AusNet Services' distribution network.
- As the proposed capital works address the impact of REFCL operation on our distribution network and its service performance, non-network solutions cannot provide an effective substitute for the proposed capital works.

In accordance with the NER requirements, we also noted these reasons are not dependent on any particular assumptions or methodologies. As the identified need must be satisfied because it reflects a compliance obligation, this DPAR must identify a network option that satisfies the RIT-D.

5 Market Benefits

The regulatory investment test for distribution requires the RIT-D proponent to consider whether each credible option could deliver relevant classes of market benefits as set out in clause 5.17.1(c)(4) of the NER. Furthermore, the AER's application guideline explains the quantification of market benefits is optional for reliability corrective action, as the credible options may be targeted to meet a compliance requirement rather than exceed it.[6]

In relation to changes in voluntary load curtailment and involuntary load shedding, the NER also states that for reliability corrective action, quantification of these benefits will only apply insofar as the market benefit delivered by the credible option exceeds the minimum standard required for reliability corrective action.[7]

Given the above provisions, we note that:

1. The Tranche three REFCL program qualifies as a reliability corrective action for the purposes of the NER, as the identified need is driven by the *Electricity Safety (Bushfire Mitigation) Regulations 2013*.
2. The credible options considered ensure compliance with, but do not exceed, the minimum standard required for reliability corrective action.
3. Our assessment is that the market benefits listed in clause 5.17.1(c)(4) will not affect the selection of the preferred option, and therefore it is not necessary to quantify them.

For completeness, in the table below we discuss each of the market benefits listed in clause 5.17.1(c)(4) and explain why it does not affect the selection of the preferred option.

Table 1: Market Benefits

Class of Market Benefit	Analysis
(i) changes in voluntary load curtailment;	The Tranche three REFCL installation will not drive changes in voluntary load curtailment on our network, as the investment will enhance protection rather than affecting the capacity of the network.
(ii) changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;	In the absence of associated reliability restoration works, the Tranche three REFCL installation could result in reduced reliability outcomes and increased network outages. This is because the REFCLs are incompatible with our existing automated approaches to restoring supply after an outage. The proposed project includes expenditure to restore the existing functionality, and therefore prevent a material deterioration in network reliability. Our assessment is that the network reliability performance will remain somewhat adversely affected as a result of REFCL operations, at least in the short term. For the purpose of this DPAR, this deterioration will not affect the selection of the preferred option.
(iii) changes in costs for parties, other than the RIT-D proponent, due to differences in: *(A) the timing of new plant;* *(B) capital costs; and*	HV customers' equipment will need to be replaced or isolated where it is not rated to the expected higher voltages from REFCL operation. No credible option has been identified that will avoid these costs.

6 AER, Application guidelines, Regulatory investment test for distribution, December 2018, page 34.

7 Clause 5.16.1(5) of the NER.

(C) the operating and maintenance costs;	
(iv) differences in the timing of expenditure;	This project will not result in changes in the timing of other expenditure.
(v) changes in load transfer capacity and the capacity of Embedded Generators to take up load;	This project will not impact on the capacity of Embedded Generators to take up load. Any connections to REFCL-protected networks need to be either REFCL compatible or isolated from REFCL operations.
(vi) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the National Electricity Market;	This project will not impact the option value in respect to likely future investment needs of the NEM.
(vii) changes in electrical energy losses; and	This project will not result in changes to electrical energy losses.
(viii) any other class of market benefit determined to be relevant by the AER.	We do not consider any other class of market benefit as relevant to the selection of the preferred option.

As we have not identified any market benefits that are relevant to the selection of the preferred option, we have not set out the methodologies used to quantify the market benefits as required by clause 5.17.4(j)(7) of the NER.

The approach adopted in this report is to select the lowest cost scope of work that is capable of achieving compliance at each zone substation. As a consequence, the proposed expenditure will maximise the present value of the net economic benefit to all those that produce, consume and transport electricity in the National Electricity Market, in accordance with clause 5.17.1(b) of the NER.

As already noted, the principal benefit from the proposed investment is the reduction in the likelihood of multi-phase powerlines starting bushfires. This category of benefit is not listed in clause 5.17.1(c)(4) and would not affect the selection of the preferred option (as it would be the same for all credible options).

6 Preferred option and proposed expenditure

As set out in section 4 and our notice of determination under clause 5.17.4(d) of the NER, there are no credible non-network options. Additionally, there is no feasible ‘do nothing’ option, as this would result in AusNet Services not complying with its legislative obligations and incurring substantial penalties.

Accordingly, the preferred option (and the only credible option) is to install REFCLs at the specified zone substations or on the 22 kV network and to undertake the necessary complementary work required to integrate the REFCLs with our network. For the required works at each zone substation, alternative options were considered and the lowest cost solution was selected. The preferred option to address the identified need is the combined lowest cost solutions identified at the Tranche three zone substations.

On 31 May 2019, AusNet Services submitted an application to the AER seeking a determination, with respect to the Tranche three installation of REFCLs and associated works, that funding for a contingent project be approved and AusNet Services’ maximum allowed revenue be adjusted in accordance with clause 6.6A.2 of the NER. The AER published its decision on 3 October 2019, approving the proposed expenditure, subject to some adjustments. Further detail on our contingent project application and the AER’s decision can be found here:

https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/ausnet-services-contingent-project-installation-of-rapid-earth-fault-current-limiters-tranche-3

With the exception of the proposed solution at Kalkallo zone substation, the information presented in this DPAR aligns with our Contingent Project Application and the AER’s decision. In relation to Kalkallo zone substation, the scope of work presented here is consistent with our submission to the AER in our 2021-26 Revised Regulatory Proposal.[8]

6.1 Timing and scope of capital works

As explained in section 1, AusNet Services is undertaking REFCL implementation works in three tranches, which is consistent with the milestones prescribed in the Regulations. The Regulations attribute points to each zone substation, with higher points allocated to those zone substations where REFCL installations will have the greatest benefit in terms of mitigating bushfire risk.

This DPAR is focused on the works required to meet our compliance obligations at the following zone substations:

- Mansfield;
- Lang Lang;
- Sale;
- Benalla; and
- Kalkallo.

The Regulations require us to meet compliance obligations by 31 May 2023. Our preferred option must therefore undertake the required works to achieve compliance by that date. Timelines for the proposed works at each zone substation are provided in Appendices 1 to 5.

8 https://www.aer.gov.au/system/files/AusNet%20Services%20-%20Revised%20Regulatory%20Proposal%20-%202021-26%20-%20December%202020.pdf

6.1.1 Scope of Capital Expenditure

The operation of a REFCL achieves network electrical protection at an enhanced level of sensitivity and speed of operation. The speed and sensitivity means that traditional protection schemes currently distributed along a feeder will not operate as they normally would to detect and isolate a faulted section of the network.

As a consequence, the proposed capital works extend beyond the immediate confines of the zone substation to ensure the network continues to operate safely and reliably. The REFCL project involves five capital expenditure workstreams, described below:

- **Zone substation works**

  Includes: REFCL installation and associated equipment within the zone substation or remotely on the 22kV network. It also includes the replacement of assets that fail during network hardening tests of the relevant high voltage network.

  Reason: In addition to installing the REFCL, additional works are required because the REFCL technology is based on a different earthing philosophy. It is essential that the zone substation operates safety and reliability in the new environment.

- **Network Balancing**

  Includes: Initially desktop and field modelling work followed by: low voltage capacitor bank installations, third phase installations and re-phasing long single phase lines.

  Reason: Long single phase (two-wire) spurs teed off three-phase lines can create significant capacitive imbalance. Fire risk reduction relies on minimal capacitive imbalance on switchable sections of the network.

- **Line and Cable Hardening**

  Includes: Surge arrestors and potential underground cable replacements.

  Reason: When an earth fault occurs, the REFCL response creates increased voltage stresses (compared to without REFCLs) on line equipment connected to un-faulted phases, which can lead to a second fault. In the absence of line hardening, the REFCL installation would increase fire risk and decrease network reliability. Increased voltage levels can also lead to cable failures.

- **Compatible Equipment**

  Includes: Automatic Circuit Reclosers (**ACR**), Voltage Regulators, sectionalisers and Capacitor Bank replacements.

  Reason: Some widely utilised line equipment cannot be used with REFCLs due to the reduced fault currents. This is separate to line hardening, which is solely concerned with the ability of line equipment to withstand over-voltage events.

- **Assisting HV customers to achieve Electricity Distribution Code (EDC) compliance**

  Includes: The costs of working with HV customers to ensure that the appropriate works are undertaken to achieve EDC compliance in readiness for the REFCL program

  Reason: The timely completion of HV customers works is essential to the successful implementation of the REFCL program. It is therefore prudent and efficient for AusNet Services to provide support to HV customers to ensure that the lowest cost, effective options are adopted to achieve EDC compliance in a timely manner.

In addition to these capital works, the preferred option will entail expenditure for an incremental increase in AusNet Services' operating expenditure.

6.1.2 Indicative capital expenditure

This section sets out indicative capital expenditure for the preferred option. As already noted, our capital expenditure estimates differ from those presented to the AER in our Contingent Project Application, principally because the proposed scope of work for Kalkallo has changed. The AER is currently considering our proposed scope of work for Kalkallo in its review of our revised regulatory proposal for the 2021 to 26 regulatory period.

It should be noted that the information presented in this DPAR does not affect our revenue allowance, which is determined by the AER. We have not, therefore, provided a reconciliation between the latest capital expenditure estimates and the AER's decision on our Contingent Project application. Instead, the information presented below addresses the requirement of clause 5.17.4(j)(11)(iii), which requires us to provide the indicative capital cost of the preferred option.

Table 2: Summary of the direct capital expenditure requirements, $m, $2021

	Total
Mansfield	11.16
Lang Lang	11.71
Sale	12.97
Benalla	15.3
Kalkallo	39.63
Total	**90.73**

Source: AusNet Services, excludes cost escalation adjustments

6.2 Indicative operating expenditure

In addition to the capital works, AusNet Services will incur on-going incremental operating expenditure as a result of the installation of REFCLs, as it requires additional resources to deliver the following activities:

- **Annual testing**

  Annual tests take the form of Primary Earth Fault Testing and Insulation Testing at each site. The first of these tests will be performed as part of the capital installation project for that site. However, annual testing is an on-going operating activity.

- **Monitoring and forecasting capacitive balancing**

  We will monitor capacitive balance and initiate corrective action where balance is outside the range necessary to achieve the specified level of performance. Forecasting capacitive balance is necessary to ensure material changes to the network (such as conductor replacement or retirement, and changes in loads or generation) are known in sufficient time to rebalance the network.

- **Fault response and analysis**

  It is expected that the time spent on fault response and analysis will increase due to the complexities of the resonant earthing network.

- **Equipment maintenance**

  Following the installation of the REFCL devices, routine maintenance is required, similar to any other plant and equipment in the zone substation.

- **Line equipment purchases**

  The introduction of the REFCL devices imposes higher voltage conditions on existing installed lines infrastructure. Some of the equipment AusNet Services uses for operating and maintaining the network is not rated to handle these higher voltages. Many of these items are capitalised, but insulated hard covers do not meet the unit cost requirements for capitalisation. Therefore, the cost of these items are treated as operating expenditure.

In the AER's draft decision for the regulatory period 2021-26, an annual total operating expenditure allowance of $1.3m was allowed from 2023 onwards in relation to the completed REFCL program at 22 zone substations. An indicative annual operating expenditure of $0.23 million for the 5 zone substation in Tranche three is therefore considered to be a reasonable estimate.

6.3 Net Present Value

Clause 5.17.4(j)(9) of the NER requires AusNet Services to provide a net present value analysis of each credible option and an accompanying explanatory statement. For the purpose of considering credible options for achieving compliance for the Tranche three REFCLs, the options are:

- Do nothing; or
- Adopt the lowest cost option at each of the relevant zone substations.

As the 'do nothing' option is not credible, the only credible option is to adopt the lowest cost solution for achieving compliance at each zone substation. The calculation of the present value for that credible option is set out in the table *below*.

Table 3: Present value of the credible option, $'000, $2021[9]

t=	*0*	*1*	*2*	*3*	*4*	
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
BN direct capex	1,347	6,964	6,742	215	-	15,267
MSD direct capex	400	9,746	1,013	-	-	11,159
LLG direct capex	1,641	4,507	5,414	145	-	11,708
SLE direct capex	2,066	4,908	5,823	171	-	12,967
KLO direct capex	1,451	16,093	22,039	41	-	39,625
Total direct capex	**6,905**	**42,217**	**41,031**	**572**	**-**	**90,725**
Total opex	**230**	**230**	**230**	**230**	**230**	**1,150**
Total expenditure	**7,135**	**42,447**	**41,261**	**802**	**230**	**91,875**

PV total expenditure =	**$88,893**	**at 2021**

As no market benefits have been identified, our preferred option has a negative NPV of $88.89 million. Importantly, reducing bushfire risk is not a relevant class of market benefit as set out in clause 5.17.1(c)(4) and, as such, is not included in this calculation. However, the Regulatory Impact Statement, prepared to support the Regulations, identified a net benefit from this project when the benefit of bushfire risk reduction is considered.[10]

The RIT-D requires the preferred option to be the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM. However, clause 5.17.1(b) of the NER states that where the identified need is for reliability corrective action, a preferred option may have a negative net economic benefit. As the REFCL program is necessary to comply with relevant regulatory instruments (and the analysis supporting those regulations identified net benefits in terms of bushfire risk reduction) it is appropriate to undertake this program regardless of the negative NPV calculated in accordance with the RIT-D.

9 The discount rate used for the purpose of calculating the present value is a pre-tax real rate, using parameter values consistent with the regulated cost of capital in the AER's most recent draft decision for our distribution network (which is a nominal, vanilla WACC).

10 Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment, 17 November 2015, p102.

7 Satisfaction of the RIT-D

In accordance with clause 5.17.4(j)(11)(iv) of the NER, we certify the proposed option satisfies the regulatory investment test for distribution. The table below shows how each of the requirements of this report have been met by the appropriate section of this report.

Table 4: Compliance with regulatory requirements

Requirement				Section
5.17.4(j) The draft project assessment report must include the following:				
	(1)	a description of the identified need for the investment;		Section 2
	(2)	the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);		Section 2 explains why reliability corrective action is required. No assumptions apply in relation to the identified need.
	(3)	if applicable, a summary of, and commentary on, the submissions on the non-network options report;		Not Applicable
	(4)	a description of each credible option assessed;		Section 6. One credible RIT-D option identified. Options for each zone substations are considered in the appendices.
	(5)	where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;		Section 5
	(6)	a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;		Section 5
	(7)	a detailed description of the methodologies used in quantifying each class of cost and market benefit;		Section 5
	(8)	where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;		Section 5
	(9)	the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;		Section 6.3
	(10)	the identification of the proposed preferred option;		Section 6
	(11)	for the proposed preferred option, the RIT-D proponent must provide:		
		(i)	details of the technical characteristics;	Section 6.1, 6.2 and Appendices 1 to 5
		(ii)	the estimated construction timetable and commissioning date (where relevant);	Appendices 1 to 5
		(iii)	the indicative capital and operating cost (where relevant);	Section 6 and Appendices 1 to 5

Requirement			Section
		(iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and	Section 7, including this table
		(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent;	Not Applicable
	(12)	contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	Section 1.2
5.17.4(k)	The RIT-D proponent must publish a request for submissions on the matters set out in the draft project assessment report, including the proposed preferred option, from: (1) Registered Participants, AEMO, non-network providers and interested parties; and (2) if the RIT-D proponent is a Distribution Network Service Provider, persons on its demand side engagement register.		Section 1.2
5.17.4(l)	If the proposed preferred option has the potential to, or is likely to, have an adverse impact on the quality of service experienced by consumers of electricity, including: (1) anticipated changes in voluntary load curtailment by consumers of electricity; or (2) anticipated changes in involuntary load shedding and customer interruptions caused by network outages, then the RIT-D proponent must consult directly with those affected customers in accordance with a process reasonably determined by the RIT-D proponent.		Not applicable
5.17.4(m)	The consultation period on the draft project assessment report must not be less than six weeks from the publication of the report.		Section 1.2

1 Appendix 1 – Mansfield Zone Substation REFCL Works

This appendix sets out the proposed scope of work associated with REFCL installation to achieve compliance with the Regulations at Mansfield (MSD) zone substation. It also discusses the consideration of alternative options.

1.1 Background

MSD zone substation is located approximately 130km north-east of Melbourne at 3,540 Maroondah Highway, Mansfield, VIC, 3722. This zone substation was established in the 1950s and supplies 6,191 customers by means of two 10/13 MVA transformers and three distribution feeders. The MSD 22kV feeders cover a total route length of 619km.

The estimated total capacitive current of the MSD 22kV network is 73A. As the capacitive current is below 135 (A), a single REFCL will be required.

1.2 Scope of work

The scope of work includes the following categories:

- Zone substation;
- Network Balancing;
- Compatible Equipment; and
- Line Hardening.

The high level scope for each of these categories is set out below.

1.2.1 Zone Substation Works

Works within the MSD zone substation include but are not limited to the design, procurement, installation/modification and commissioning of the following:

Primary:

- Specification, procurement and installation of one REFCL incorporating an Arc Suppression Coil (ASC), Residual Current Compensation device and a control system.
- Suitable housing for REFCL control systems.
- Suitable housing for associated 22kV control equipment.
- Procurement and installation of one neutral bus switchboard. The introduction of the REFCL requires a neutral bus which enables different earthing arrangements to be automatically configured. The switchboard facilitates remote year round selection of earthing arrangements and operating modes and provides the ability to balance bushfire risk reduction with network reliability, depending on network and weather conditions. Modifications will be required to the existing neutral earthing to accommodate the neutral bus switchboard.
- Upgrade of the two existing station service transformers and changeover boards. This work is required because the alternating current (AC) supply requirement dramatically increases due to the REFCL installation. The station service transformers are proposed to be sized at 500kVA.
- Upgrade upstream 415V change overboard suitable for uprated station service transformers.

- Replacement of all 22kV surge arrestor sets within the zone substation and feeder exits.
  - 3x feeder sets; and
  - 2x transformer sets.
- Install 2x single phase surge arrestors for neutral structures for transformers.
- Replacements of 3x outdoor feeder circuit breakers in situ.
- Replace 4x isolators including MSD 1 FDR CB B/S isolator; MSD 1 FDR T/FER BUS isolator, MSD 1 FDR CB FDR/S Isolator and 22kV B/S VT fused isolator.
- Install 5x sets of zero sequence CTs on 3x feeders and 2x station service transformers.
- Install 2x 22kV post CTs (1 per transformer).
- Install 2x standard neutral isolator structures.
- Replace 1x 3-ph VT set on bus #2.
- Transformer tests including PD testing, power transformer condition monitoring tests and REFCL operational tests on each transformer (there are 2x power transformers).

Primary Cables:

- Underground the existing overhead feeder MSD2 to accommodate zero sequence CTs.
- Relocate 66kV line to Merrijig south to 2m from southern boundary fence and transpose vertically – including the installation of 2x poles.
- Install the following 22kV cables:
  - No.1 S/S Trans to MSD1 feeder (50m), 3C 185mm², Al XLPE;
  - No.2 S/S Trans to MSD2 feeder (80m), 3C 185mm², Al XLPE;
  - No.1 GFN to new No.1 22kV Switched Neutral Bus Kiosk; (20m), 1C, 185mm², Al XLPE;
  - No.1 Trans Neutral Isolator to No.1 Switched 22kV Neutral Bus Kiosk; (50m), 1C, 185mm², Al XLPE;
  - No.3 Trans Neutral Isolator to No.1 Switched 22kV Neutral Bus Kiosk; (80m), 1C, 185mm², Al XLPE; and
  - Replace two (2) 22kV Feeders; (100m each), 3C, 300mm², Al XLPE.
- Testing and potential replacement of cable equipment which are at risk of failure if operated at elevated voltages. This testing should include all 22kV station cables and feeder exit cables.

Civils:

- Extend earth grid.
- Install 1x footing for the GFN incl. bund set system (similar to WYK).
- Resurface the switchyard
- Extend cable trenches

Protection and Control:

- Replacement and extension of existing protection and control equipment with equipment capable of operating in several modes including resonant earthing and traditional earth fault modes. Additional control systems are required to provide the interface between the

REFCL and AusNet Services' equipment. New protection devices are also needed to provide an adequate backup for the REFCL for the instances of mal operation:

- Install 1x GFN changeover board;
- Install 1x GFN control system;
- Install 1x Neutral bus kiosk controller;
- Replace TX 1 and TX 3 X and Y protection relays (for Transformer Group) existing McColl BDS2 and ABB RI relays are applied as X and Y protection for the Transformer Group and are obsolete electromechanical type;
- Replace feeder prot x3, existing GE F650 relays 22kV to be replaced by ABB REF630 relays;
- Install 1x C30 REFCL interface controller relays;
- Install 1x REFCL interface panels each will have 2x ELSPEC and 1x C30 relays;
- Install 1x Power Quality Meter (PQM);
- Protection review required for transformers, feeders, MEF & BEUF, Bus and 66/22 TX's addressing protection sensitivity, settings and time grading between stages when NER is in service;
- 66kV CB failure protection is required if Zone 3 Distance protection settings review comes up short;

- The following is also noted and required:
  - The existing REF630 Master Earth Fault relay is suitable and will only need a firmware upgrade;
  - The existing Back Up Earth Fault relay is new and will only need a firmware upgrade; and
  - Installation of monitoring equipment is required to demonstrate compliance with regulations and enable remote engineering access to control systems.
- Standard protection and control schemes may require modifications to suit specific site conditions. Any such modification should be carried out in consultation with Technical Standards and Services.

Network:

- Feeder rearrangements need to be considered along with loading studies on each transformer.
- In relation to network hardening tests on the MSD 22 kV network prior to commissioning the REFCLs, our expectation is that there is a reasonable likelihood that some surge arrestors, insulators, pole top transformers and/or cables may fail and require replacement.
- Development and execution of a community engagement plan for works associated with the MSD network REFCL implementation. Community engagement is required to explain the likely customer reliability impact during the new network insulation tests. The importance of effective community engagement has been highlighted by the Woori Yallock REFCL implementation in September 2016, which led to issues being raised by customers, media, the community and the Victorian Parliament.

Communications:

- Upgrade tele-protection equipment and communications:
  - 4x c37.94 cards required for the PDH and 4x TPS Frames;

- Install 10km of ADSS;
- Install 1x RS2488 switch; and
- Install 1x 2488 clock.

Other:

- The above scope of work is based on 3-minute network insulation testing utilising the REFCL. The designer should ensure ratings are verified to enable phase to ground operation of 24.2kV for 3 minutes.

1.2.2 Network Balancing

The high level works required to minimise network capacitive imbalance on the MSD 22kV network feeders include the following:

- Adding a third conductor to a single-phase spur (practical for cable) to convert it to three-phase;
- Installing 18x LV balancing capacitor banks at single-phase spur takes offs or on the three-phase back bone to balance switchable sections of the network;
- Performing 33x single-phase spur or distribution substation rotations, e.g. converting a spur connected on red and white to red and blue; and
- Ensure leakage current is maintained once REFCL is in service, by installation of solid fuse links and ensuring phase nameplates are accurate on 15x feeders at each automatic switchable section.

The approach to the scope the works will be in two stages:

- First stage: Known as coarse balancing and involves excel modelling of the capacitance of the network and selecting a combination of works above to achieve the less than 0.1 A network leakage current required; and
- Second stage: After performing measurements of switching sections, fine balancing will be performed which will require tuning of the above solutions.

1.2.3 Compatible Equipment Works

- The high level works include the replacement of 4 ACRs with modern equivalents capable of working on resonant electricity networks.

1.2.4 Line Hardening Works

- The high level scope includes replacing 1,362 22kV line surge arrestors at 599 sites.
- Replacement activities are required at three 22kV line asset types: cable head poles, transformers and switches. Work is to be completed across south-east and northern regions.

1.3 Options considered

The key issues impacting the installation of REFCL technology at MSD is the lack of physical space in the yard and the existing site control room. The existing site control room is small with insufficient space; it does not have the physical room necessary for the required installation of

REFCL technology and associated 22kV protection equipment. Due to its size, the existing control room is unsuitable for reuse.

As a result, options need to be measured for the housing of the necessary REFCL technology and associated protection equipment. Three options have been considered in the preparation of this business case, as described in the table below.

Table 5: Options considered

Option	Description Summary
BAU	Business as usual – not viable.
1	Install REFCL technology and associated equipment. Further, install one standard REFCL control room and one modular control room
2	Same as above option, but install one tilt slab control room to house REFCL control units and associated 22kV protection equipment.

1.3.1 Business as usual

The business as usual option does not allow for the installation of REFCL technology and does not comply with the *Electricity Safety (Bushfire Mitigation) Regulations 2013.* Furthermore, the Victorian Government has amended the *Electricity Safety Act* to include a civil penalties scheme for certain non-compliances with these Regulations. Failure to have the REFCL operating by 30 April 2023will incur a one-off civil penalty of $4M, and a fine of $5,500 per point for each day the criteria is not met after that date. As a result, this option is not viable and has not been considered further. A summary of costs and benefits is provided in the table below.

Table 6: Costs and benefits of business as usual option

Capex and Opex	Not applicable.
Community Costs and Benefits	The community serviced by the Mansfield zone substation would be exposed to the same level of risk as now of fire starts from 22kV phase to earth faults in the absence of a REFCL installation. On this basis, the status quo does not maximise net benefits for the community.

1.3.2 Option 1 - Install REFCL technology and associated equipment. Further, install one standard REFCL control room and one modular control room (preferred option).

This option involves the installation of REFCL technology at Mansfield zone substation through the installation of one standard REFCL control room and one modular control room to house required 22kV protection and control equipment. This is a viable option at Mansfield in comparison to Option 2 as it minimises project risk throughout what would otherwise be a complex construction phase.

In addition, this preferred option involves the following technologies and approaches to capacitively balance the MSD 22kV network:

- Installing LV balancing capacitor banks at single phase spur take offs;
- Installing LV balancing capacitor banks on the three-phase back bone to balance switchable sections of the network; and

- Performing single-phase spur or distribution substation rotations, e.g. converting a spur connected on red and white to red and blue.

This approach to balancing to meet the Regulations specifications introduces LV balancing capacitor banks on the three-phase back bone. This will minimise overhead lines works and costs, by artificially simulating the required increase in balancing capacitance.

This option also replaces ACRs and ensures achievement of required safety targets through implementation of REFCL along with no impact on reliability of the feeders due to mal-operation of protection and ACRs; and replaces unacceptable 22kV line surge arrestors on MSD feeders which are unable to withstand REFCL voltages.

This option is recommended for the following reasons:

- Lowest cost technically acceptable option that enables AusNet Services to meet its regulatory compliance obligations;
- Less project and deliverability risk than other options; *and*
- Helps achieve the objectives of safe REFCL operation and in turn the requirements of the Bushfire Mitigation Regulations.

A summary of costs and benefits is provided in the table below.

Table 7: Costs and benefits of Option 1

Capex and Opex	Capex installation of a REFCL and station and associated works incurs a direct expenditure of $10,928K including management reserve of $546K and Written Down Value (WDV) of $265K. This represents a present value capital cost of $12,059K.
Community Costs & Benefits **(Regulated projects)**	Assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the Mansfield zone substation will reduce fault energy leading to a decrease the risk of fire starts from 22kV single-phase to earth faults.

1.3.3 Option 2 – Same as above option, but install one tilt slab control room to house REFCL control units and associated 22kV protection equipment.

This option is the same as Option 2, however installs one tilt slab control room to house REFCL control units and associated 22kV protection equipment. The tilt slab control room presents issues with deliverability as it presents a 36-week lead time and will increase the risk of having the REFCL installed before the Tranche three penalty date. It is also ~$800K more expensive than the REFCL room and modular control room presented in Option 2. Due to the delivery and construction risk associated with the tilt slab control room, this option is not recommended.

The table below provides a summary of this option’s costs and benefits.

Table 8: Costs and benefits of Option 2

Capex and Opex	Capex installation of a REFCL and station and associated works incurs a direct expenditure of $12,259K including management reserve of $613K and Written Down Value (WDV) of $265K. This represents a present value capital cost of $13,526K.
Community Costs & Benefits	Assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the Mansfield zone substation will reduce fault energy leading to a decrease in the risk of fire starts from 22kV single-phase to earth faults.

This option delivers the same benefit as Option 1, but is more expensive and therefore is not the preferred option for MSD zone substation.

1.4 Input assumptions and sensitivity analysis

Each option employs a similar mix of capital and operating expenditure, and they also entail similar levels of expected delivery cost risk and involuntary supply interruption costs. Consequently, the ranking of the options will not change by varying these input assumptions. In addition, the ranking of options is also unaffected by changes in the cost of capital.

The timing of the action required to address the identified need is driven by our mandatory bushfire mitigation obligations, and therefore alternate project timings have not been considered.

In view of these considerations, input assumption scenarios and sensitivity analysis are not presented in this report.

1.5 Preferred Option at MSD zone substation

Clause 5.17.1 (b) of the NER states that the preferred option must:

> *"maximise the present value of the net economic benefit to all those that produce, consume and transport electricity in the National Electricity Market",*

and further that

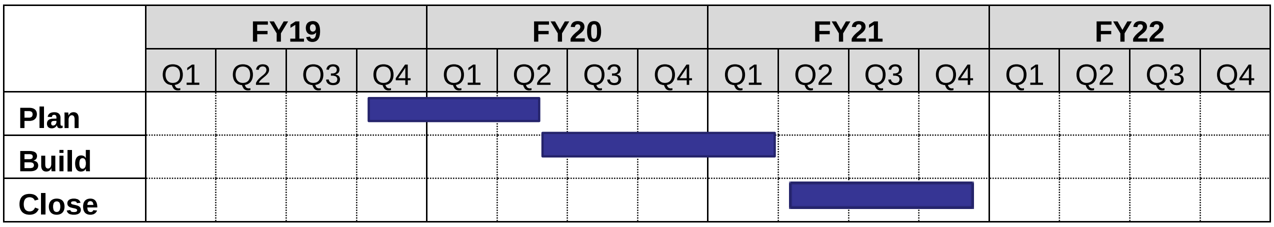
> *"a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."*

As explained in section 1.3.2 above, Option 1 is identified as the preferred option in relation to MSD because it meets the mandatory requirements of the Amended Bushfire Mitigation Regulations and maximises the net economic benefit compared to the other credible and technically feasible options at that zone substation. It should be noted, however, that the RIT-D project is to achieve compliance at all Tranche three zone substations – and therefore the preferred option at MSD is one component of the RIT-D project.

The legislated requirement to complete the work does not provide scope to consider delaying the work or to consider alternate project timing.

The proposed timing of work is set out below, noting that FY refers to the period from 1 April to 31 March. The timing may change to address emerging issues and priorities.

Figure 6: Timing of work at MSD



2 Appendix 2 – Lang Lang Zone Substation REFCL Works

This appendix sets out the proposed scope of work associated with REFCL installation to achieve compliance with the Regulations at Lang Lang (LLG) zone substation. It also discusses the alternative options that were considered.

2.1 Background

LLG zone substation is located approximately 85 km south-east of Melbourne on Westernport Road, Lang Lang. This zone substation was established 2007 and supplies 6,585 customers by means of one 20/33 MVA transformer and four distribution feeders. The LLG electricity distribution area consists primarily of residential areas as well as scattered industrial and commercials sites in and around Lang Lang and the nearby surrounding areas including Nyora, Koo Wee Rup and Grantville. The LLG 22 kV feeders cover a total length of 498 km.

The estimated total capacitive current of the LLG 22 kV network is 67.7 Amperes (A). As the capacitive current is below 101A, a single REFCL will be required.

2.2 Scope of work

The high level scope of works for this project involves the following:

- Installation of new modular building with urban type 22kV switchboard.
- Retire existing 22kV switchboard and utilise old switchboard room for new REFCL equipment.
- Installation of Siemens-Trench REFCL primary equipment including Arc Suppression Coil (ASC), Inverter and Neutral Bus Kiosk.
- Replacement of existing Station Service Transformers, batteries replacement and feeders/lines.

Further information in relation to the scope is set out below.

2.2.1 Primary plant

- Establish a new urban type 22kV modular switchroom complete with a control room which includes the following:
  - Seven (7) zero sequence CTs
- Provision for modification of new switchroom for the tie breaker to a feeder breaker as below:
  - Bustie CT type changed match other feeders
  - Secondary design revised:
    - Feeder panel - additional REF630, including aux. relays, MCBs, terminals, links
    - Cap Bank & Bus ties panel - delete REF630, including aux. relays, MCBs, terminals, links
    - Bus X Prot, Bus Y Prot and Comms/DFR panels revised accordingly
    - DCDB and ITC panels revised accordingly
    - Cable Schedule revised accordingly

- Establish a new Siemens-Trench REFCL system namely:
  - One (1) Arc Suppression Coil (ASC)
  - One (1) Residual Current Compensator Inverter (RCC)
- Establish a new 22kV Neutral Bus Kiosk (NBK)
- Earthing study
- Retire existing and re-route 3C 185 mm2, AL XLPE cables for the following:
  - Capacitor bank to the new switchroom
  - No.1 Station Service Transformer to the new switchroom
  - No.2 Station Service Transformer to the new switchroom
- Retire existing and re-route six (6) 1C 500mm2, Cu XLPE cables from:
  - No.1 Transformer to new 22kV Switchboard
- Retire existing and install 1C 185 mm2, AL XLPE 22 kV neutral cables, from:
  - No. 1 Transformer neutral isolator to No. 1 Neutral Bus kiosk
  - No. 1 NER to No. 1 Neutral Bus Kiosk
  - No. 1 GFN to No. 1 Neutral Bus Kiosk
- Retire existing 300kVA station service transformer and establish two (2) new 500kVA (22/0.415kV) station service transformers
- Replace one (1) 22kV surge arrestor for the neutral structure on the transformer
- Transformer tests as stipulated by AusNet Asset Engineering including:
  - partial discharge (PD) testing
  - power transformer condition monitoring test
  - REFCL operational test
- Cable Partial discharge and high potential tests for following cables after installation:
  - LLG11 Feeder exit cable
  - LLG12 Feeder exit cable
  - LLG13 Feeder exit cable
  - LLG14 Feeder exit cable
  - No. 1 Capacitor Bank cable
  - No. 1 Transformer 22 kV cables
  - No. 1 Station Service Transformer cables
  - No. 2 Station Service Transformer cables
- Replace four (4) capacitor bank reactor post insulators
- Retire and removal of existing switchboard pad and transportation to storage location
- Commissioning and testing of the new 22kV switchgear, ASC and NBK

2.2.2 Civil infrastructure

- New equipment supports footings for:
  - One (1) Arc Suppression Coil (ASC)
  - Two (2) 500 kVA (22/0.415V) Station Services Transformers
  - One (1) Neutral Bus Kiosk
- Modify existing equipment support and footings for:
  - One (1) 22kV Surge Arrestor
  - Two (2) Neutral Current Transformer
- Restoration of the disturbed switchyard surfaces
- Installation of two (2) lights poles
- Provision for temporary security system during construction
- Establish a final security system, including:
  - Security Signage
  - Access Control
  - Spectur Units
- Footings for an urban type 22kV modular switchroom complete with a control room
- Building surveyor to address the current moisture ingress issues within the old 22kV Switchboard
- Establish new cable trenches for the primary equipment as listed below:
  - Arc Suppression Coil
  - Neutral Bus Kiosk
  - New Station Service Transformers
- Conduit for feeder exit cable
- Establish new cable support structures and footings.
- Establish two (2) new building lighting (wall mounted) for new switchroom
- Site drainage works for new switchroom
- Provision for a Geotechnical Engineer to be present and to witness that the bearing pressures required for each footing is achieved, prior to any excavation works being undertaken for that associated footing. This is applicable for the SS Tx, NBK, Switchroom, and ASC
- Geotechnical investigation and site survey (including underground services location).
- Establish bunded area for ASC and pumped connection to existing environmental systems

2.2.3 Associated works

Other associated works includes the following:

- Protection & Control works

- REFCL Commissioning and Compliance Testing
- SCADA & Communications works
- Metering, Monitoring and AC/DC Supplies works
- Feeder exit works
- Other additional items (PMO, customer engagement, outages, planning permits, council approvals, back-up generations etc.)

2.3 Options considered

Three options were considered in this assessment, as described in the table below.

Table 9: Options considered

Option	Description Summary
BAU	Business as Usual
1	Install REFCL technology and associated equipment using layout which requires extension of switchyard
2	Install REFCL technology and associated equipment without extension of switchyard

The existing site control room at LLG ZS is congested and does not have the physical space for the required installation of REFCL technology, namely the inverter unit, REFCL control panels, protection and communications modifications along with network monitoring and switchgear interface relays.

Further, the existing 22 kV switchboard cannot withstand the increased voltages induced by the REFCL equipment. This is mainly due to the age and condition of the switchboard and therefore needs replacement. The existing switchboard building is also known to have moisture ingress issues which will need to be rectified.

As a result, options need to be measured for the housing of the necessary REFCL technology, new switchboard and associated equipment.

2.3.1 Business as usual

The business as usual option does not allow for the installation of REFCL technology and does not comply with the *Electricity Safety (Bushfire Mitigation) Regulations 2013.* Furthermore, the Victorian Government has amended the *Electricity Safety Act* to include a civil penalties scheme for certain non-compliances with these Regulations. Failure to have the REFCL operating by 1 May 2023 will incur a one-off civil penalty of $2M, and a fine of $5,500 per point for each day the criteria is not met after that date.

As a result, this option is not prudent nor financially viable and therefore has not been considered further. The costs and benefits of this option are described in the table below.

Table 10: Costs and benefits of business as usual option

Capex and Opex	Not applicable
Community Costs & Benefits	The community serviced by the LLG zone substation would be exposed to the same level of risk as now of fire starts from 22 kV phase to earth faults in the absence of a REFCL installation. On this basis, the status quo does not maximise net benefits for the community.

2.3.2 Option 1 - Delivery of REFCL involving extension of switchyard

This option involves the installation of REFCL technology and associated equipment as well as the new 22 kV switchboard in a new modular building complete with one control room by extending the existing switchyard. This would allow the existing access road to be maintained, easier installation of the switchroom and associated cabling / trenching and also room for any possible future installations required on this site. The existing switchboard building will be repurposed to house REFCL equipment.

However, this option requires a higher total estimated expenditure ($1.27M more than Option 2) and therefore is not recommended. The table below summarises the cost and benefits of this option.

Table 11: Costs and benefits of Option 1

Capex and Opex	Capex for the works will incur a direct expenditure of $12,781.8k including management reserve of $647.3k and Written Down Value (WDV) of $843.3k. This represents a present value capital cost of $13,402.2k.
Community Costs & Benefits **(Regulated projects)**	Assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the LLG zone substation will reduce fault energy leading to a decrease in the risk of fire starts from 22 kV single-phase to earth faults.

This option delivers the same benefit as Option 2 (below), but is more expensive and therefore is not the preferred option for LLG zone substation.

2.3.3 Option 2 (recommended option) – Delivery of REFCL without extension of switchyard

Option 2 involves the installation of REFCL technology and associated equipment as well as the new 22 kV switchboard in a new modular switchroom complete with one control room. The existing switchboard building will be repurposed to house REFCL equipment. However, this option does not require extension of the switchyard due to the proposed layout of the switchroom. The benefits of this option are:

- Reduce the project risk as a result of extending into an unknown area
- Lower capex investment as a result of not extending the switchyard
- Better utilisation of existing space
- Future expansion would still be possible at the front of the yard

Therefore, this is the recommended option. The costs and benefits of this option are set out in the following table.

Table 12: Costs and benefits of Option 2

Capex and Opex	Capex installation of a REFCL and station and associated works incurs a direct expenditure of $11,707.7k including management reserve of $647.3k and Written Down Value (WDV) of $843.3k. This represents a present value capital cost of $12,422.5k.
Community Costs & Benefits	Assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the Lang Lang zone substation will reduce fault energy leading to a decrease in the risk of fire starts from 22 kV single-phase to earth faults.

2.4 Input assumptions and sensitivity analysis

Each option employs a similar mix of capital and operating expenditure, and they also entail similar levels of expected delivery cost risk and involuntary supply interruption costs. Consequently, the ranking of the options will not change by varying these input assumptions. In addition, the ranking of options is also unaffected by changes in the cost of capital.

The timing of the action required to address the identified need is driven by our mandatory bushfire mitigation obligations, and therefore alternate project timings have not been considered.

In view of these considerations, input assumption scenarios and sensitivity analysis are not presented in this report.

2.5 Preferred Option at LLG Zone Substation

Clause 5.17.1 (b) of the NER states that the preferred option must:

> *"maximise the present value of the net economic benefit to all those that produce, consume and transport electricity in the National Electricity Market",*

and further that

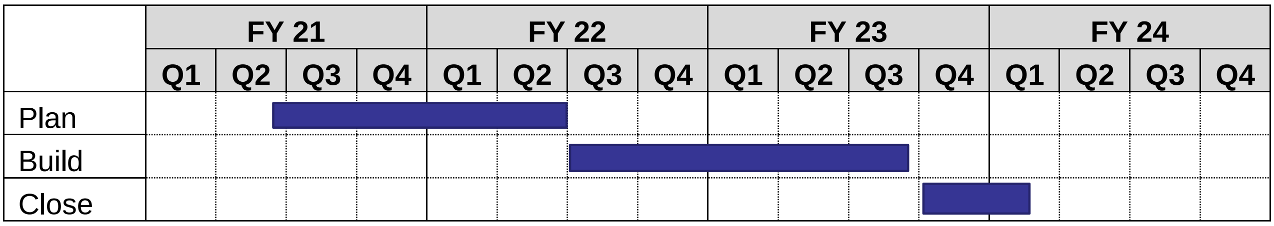
> *"a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."*

As explained above, Option 2 is identified as the preferred option at LLG zone substation because it meets the mandatory requirements of the Amended Bushfire Mitigation Regulations and maximises the net economic benefit compared to the other credible and technically feasible options. It should be noted, however, that the RIT-D project is to achieve compliance at all Tranche three zone substations – and therefore the preferred option at LLG is one component of the RIT-D project.

The legislated requirement to complete the work does not provide scope to consider delaying the work or to consider alternate project timing.

The proposed timing of work is set out below, noting that FY refers to the period from 1 April to 31 March. The timing may change to address emerging issues and priorities.

Figure 7: Timing of work at LLG



3 Appendix 3 – Sale Zone Substation REFCL Works

This appendix sets out the proposed scope of work associated with REFCL installation to achieve compliance with the Regulations at Sale (SLE) zone substation. It also discusses the alternative options that were considered.

3.1 Background

SLE ZSS is located on Raglan Street in Sale and is located approximately 215 km south-east of Melbourne. This zone substation was established in the early 1970's and supplies approximately 12,750 customers by means of two (2) 10/13.5 MVA, one (1) 20/33 MVA transformers and four (4) distribution feeders.

The SLE 22 kV feeders cover a total route length of 667km. The estimated total capacitive current of the SLE 22 kV network is 67.9 Amperes (A). As the capacitive current is below 101A, a single REFCL will be required. The SLE electricity distribution area consists primarily of residential areas in and around Sale and surrounding areas including Loch Sport.

3.2 Scope of work

The high level scope of works for this project is summarised below

- Install a single Trench REFCL inclusive of an Arc Suppression Coil (ASC), Inverter and a control system;
- Install one (1) 22 kV Neutral Bus Kiosk;
- Replace existing 22 kV CBs SLE31 and SLE32 with new DTCBs;
- Replace existing 3 x 4 MVAR capacitor bank with a new metallic enclosed 4 x 3MVAR (standard Arrangement) cap-bank;
- Replace both Station Service Transformers (25kVA and 100kVA) with two (2) 500kVA kiosk type Station Service Transformers;
- Install a new REFCL Room;
- Install a new Battery Room;
- Install REFCL AC Changeover Board & Inverter inside a new REFCL Room;
- Install two (2) new 22 kV RDBs for the No.2 and No.3 Transformers;
- Replace twelve (12) existing 22 kV underslung isolators;
- Replace twelve (12) single phase 22 kV Surge Arrestors for the No.2 and No.3 Transformers and SLE31 and SLE32 feeders;
- Install three (3) single phase Surge Arrestors on the neutral No.1, No.2 and No.3 Transformer;
- Replace four (4) 22 kV Neutral CTs for No.2 and No.3 Transformers;
- Retrofit five (5) sets of zero sequence CTs in the existing Switchroom for:
  a. 4 x Feeders (incl. No.1 SSTx); and
  b. 1 x for Cap Bank.
- Install three (3) sets of zero sequence CTs on the SLE31 and SLE32 feeders and No.2 Station Service Transformer;
- Installation of a pole mounted 300 kVA isolating transformer with ACR protection including new concrete poles, isolating transformer, ACR and HV fuses;

- Extend the Earth Grid over new footprint for the replacement of the existing 3 x 4MAR Cap Bank with a new 4 x 3MVAR metal enclosed REFCL compliant Cap Bank*** and move to the No.2 Bus;
- Design and Install footing for: Battery Room*, ASC, 2 x SSTx Kiosks, 1 x 22 kV NBK, 1 x metal enclosed REFCL compliant Capacitor Bank, No. 2 and No.3 Transformer cable structure, 1 x outdoor 22 kV ITC cabinet, REFCL Room** and 2 x 22 kV DTCBs;
- Extension of cable trenches and installation of conduits as required;
- Reinstall/establishment of switchyard surface and construct roadways as required;
- Installation of approx. 1000m of new 22 kV cables;
- Partial Discharge and High Potential testing of all existing cables required to identify if a full cable replacement is necessary:
  c. No. 1 Transformer 22 kV cables (incl. phase and neutral); and
  d. Two (2) existing Feeder Exit cables (SLE11, SLE14).
- Testing of all new 22 kV cables installed prior to commissioning;
- Replacement of duplicated 125V DC battery systems in the new Battery Room; *and*
- Replacement and modification of protection and control schemes for REFCL suitability.

3.3 Options considered

Three options have been considered in this assessment as per table below. The duration of analysis is over 40 years from FY 2020/21 to FY2059/60, based on average regulatory service life of new assets, to be installed under the project. The options considered are listed in the table below.

Table 13: Options considered

Option	Description Summary
BAU	Business as Usual
1	Install REFCL technology and associated equipment using layout which requires extension of switchyard
2	Install REFCL technology and associated equipment without extension of switchyard

3.3.1 Business as usual

This option involves continuation of poor condition assets in service without installation of REFCL technology and without any planned replacement.

This is not a viable option as the community cost and benefits have been calculated as part of the overall REFCL program by the Victorian Government and installation of REFCL technology is a mandatory program. Additionally, this project is only one component of delivering the overall community benefits and does not deliver a portion of the benefits without the other components. As such, it is inappropriate to include a portion of the community cost and benefits as part of the assessment criteria – specifically for BAU option, in Tables 5.1.

The majority of the primary assets involved in this project are not suitable for REFCL installation and hence require replacement. Also, an explosive failure could lead to personal injuries due to involvement of porcelain housing/bushings, presenting increased safety risk for an OH&S incident. The costs and benefits of this option are set out in the table below.

Table 14: Costs and benefits of business as usual option

Capex and Opex	Not applicable.
Community Costs & Benefits	The community serviced by the SLE zone substation would be exposed to the same level of risk as now of fire starts from 22 kV phase to earth faults in the absence of a REFCL installation. On this basis, the status quo does not maximise net benefits for the community.

3.3.2 Option 1 (preferred option) - SLE T3 REFCL Works with Outdoor CBs Option

This option involves installation of REFCL technology at SLE ZSS including all required associated components. This option also involves replacement of existing 22 kV assets required due to either compatibility issues with REFCL technology or due to poor condition-likely to fail in near future. This option will ensure smooth operation of REFCL technology to reduce the risk of bushfire in Sale area and would continue to maintain current supply reliability to local community/customers, supplied by SLE ZSS.

This option avoids REFCL penalties and improves regulatory and government compliances.

Additionally, this option retires all the old poor condition assets not suitable for REFCL technology, in current SLE ZSS and reduces the risk of asset failures/damages including financial implications. Reduction in asset failures reduces the risk of injuries to AusNet Services employee/contractors should they exposed to an explosive failure of old poor condition assets. Accordingly, this project improves the safety for AusNet Services employees/contractor.

A short summary of the various costs and benefit values from the financial modelling has been provided in the table below. Economic evaluation through the financial modelling has indicated that this option presents a total PV cost of $14.578M and a positive NPV of $2.185M over the modelling period.

As this option provides the lower PV cost, saves the REFCL penalty cost, ensures reliable supply to the Sale community with reduction in bushfire and safety risk; this is the recommended option. The costs and benefits of this option are set out in the table below.

Table 15: Costs and benefits of Option 1

Capex and Opex	Capex for this option is the delivery budget of $14.287M to be mainly spent between FY2021 and FY2024. Some of the money has already been spent since FY2018. The total PV of Capex cost is (nominal and discounted) estimated as $13.778M. Opex Cost: Only one ongoing Opex cost has been considered as per following: a) Planned and Unplanned Opex Costs related to new Outdoor Assets This involves the planned and unplanned Opex cost associated with new, outdoor, 22kV assets (CB, CT, VT, and disconnectors) replaced under the project. All the Opex cost related with REFCL equipment and existing assets have been excluded as these costs are common for both financially evaluated options. Additionally, Opex cost related with outdoor assets replaced by an indoor asset have been excluded as that is also same for both options. The planned and unplanned Opex cost has been estimated based on AST experience for maintenance of 22kV new outdoor assets starting at $2.5k per annum and increasing at a constant rate of 8% every year for outdoor options. Accordingly, a cumulative Opex cost of $2.5k per annum in FY24 gradually increasing to $39.9k per annum in FY60 has been forecast over the modelling period, for all the outdoor assets replaced by outdoor assets under this project. The total PV of Opex cost is (nominal and discounted) estimated as $215.1k.

Community Costs & Benefits	One community cost has been considered in this business case as per following: a) Network Impact/ Unserved energy/ GSL Payments Unserved Energy/GSL payments or network impact cost is estimated at $15k per annum for new outdoor assets with a gradual increase of 4% every year over the modelling period. The increase per annum rate has been taken as 50% of Opex cost rate above, based on assumption that all asset failure doesn't result in network impact due to redundancy. Accordingly, the cost is estimated as $15k per annum in FY24 gradually increasing to $61.6k in FY60, over the modelling period, similar to Opex cost. The total PV of Community cost is (nominal and discounted) estimated as $584.7k. Also, REFCL technology assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the SLE zone substation will reduce fault energy leading to a decrease in the risk of fire starts from 22 kV single-phase to earth faults.

3.3.3 Option 2 - SLE T3 REFCL Works with Indoor CBs (Switchboard) option

This option also involves installation of REFCL technology at SLE ZSS including all required associated components including replacement of existing 22kV assets required due to either compatibility issues with REFCL technology or due to poor condition-likely to fail in near future, similar to preferred option. However, the only difference is that several 22kV assets such as CBs, VTs, CTs and isolators are proposed to be replaced by an indoor environment – in a new switchboard.

This option provides all the reliability and community benefits, similar to preferred option, with further improvement in reliability and reduced ongoing planned and unplanned maintenance. This option also provides better option in terms of future expansion of SLE ZSS with ease of connection of new assets.

However, this option requires significantly higher Capex initially, with higher overall PV cost over the modelling period. This is due to mainly two reasons as per following:

- There are only two outdoor CBs need to be replaced while standard switchboard comes with at least six to seven CBs; and
- The current load growth trend indicates very slow or no-load growth due to increasing household solar installations and accordingly not many additional assets are forecast to be added at ZS in near foreseeable future. AusNet Services planning team has indicated that current assets are sufficient to supply the load in Sale for next 15 to 20 years.

A short summary of the various costs and benefit values from the financial modelling has been provided in the table below. Economic evaluation through the financial modelling has indicated that this option has the higher total PV cost of $16.656M and require significantly higher ($2.65M) delivery budget in comparison to preferred option.

As this option requires significantly higher Capex budget and does not provide additional benefits in proportionate to additional budget, this option is not recommended. The costs and benefits of this option are set out in the table below.

Table 16: Costs and benefits of Option 2

Capex and Opex	Capex for this option is the delivery budget of \$16.937M to be mainly spent between FY2021 and FY2024. Some of the money has already been spent since FY20218. The total PV of Capex cost is (nominal and discounted) estimated as \$16.321M. Opex Costs: This involves the planned and unplanned Opex cost associated with new, indoor, 22kV switchboard to be installed to replace two outdoor CBs and associated outdoor assets. Ongoing Opex costs related with REFCL equipment, existing assets and other indoor assets have been excluded, as mentioned in preferred option above. The planned and unplanned Opex cost has been estimated based on AST experience for maintenance of 22kV new switchboard assets starting at \$1.25k per annum and increasing at a constant rate of 5% every year for indoor option. Both the starting initial Opex cost and annual increase rate has been assumed lower in comparison to preferred option as indoor assets are less exposed to open environment. This reduces the likelihood of failures of assets leading to reduced ongoing Opex costs over the life cycle of assets. Accordingly, a cumulative Opex cost of \$1.25k per annum in FY24 gradually increasing to \$7.2k per annum in FY60 has been forecast over the modelling period, for all the outdoor assets replaced by the switchboard under the project. The total PV of Opex cost is (nominal and discounted) estimated as \$58.7k.
Community Costs & Benefits	One community cost, similar to preferred option, has been considered in this business case as per following: a) Network Impact/ Unserved energy/ GSL Payments Unserved Energy/GSL payments or network impact cost is estimated at a lower rate of \$10k per annum for new indoor assets with a lower gradual increase of 2% every year over the modelling period, similar to Opex costs. Accordingly, the cost is estimated as \$10k per annum in FY24 gradually increasing to \$20.4k in FY60, over the modelling period, similar to Opex cost. The total PV of community costs is (nominal and discounted) estimated as \$275.9k. Also, REFCL technology assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the SLE zone substation will reduce fault energy leading to a decrease in the risk of fire starts from 22 kV single-phase to earth faults.

This option delivers the same benefit as Option 1, but is more expensive and therefore is not the preferred option for SLE zone substation.

3.4 Input assumptions and sensitivity analysis

Each option employs a similar mix of capital and operating expenditure, and they also entail similar levels of expected delivery cost risk and involuntary supply interruption costs. Consequently, the ranking of the options will not change by varying these input assumptions. In addition, the ranking of options is also unaffected by changes in the cost of capital.

The timing of the action required to address the identified need is driven by our mandatory bushfire mitigation obligations, and therefore alternate project timings have not been considered.

In view of these considerations, input assumption scenarios and sensitivity analysis are not presented in this report.

3.5 Preferred Option at SLE

Clause 5.17.1 (b) of the NER states that the preferred option must:

"maximise the present value of the net economic benefit to all those that produce, consume and transport electricity in the National Electricity Market",

and further that

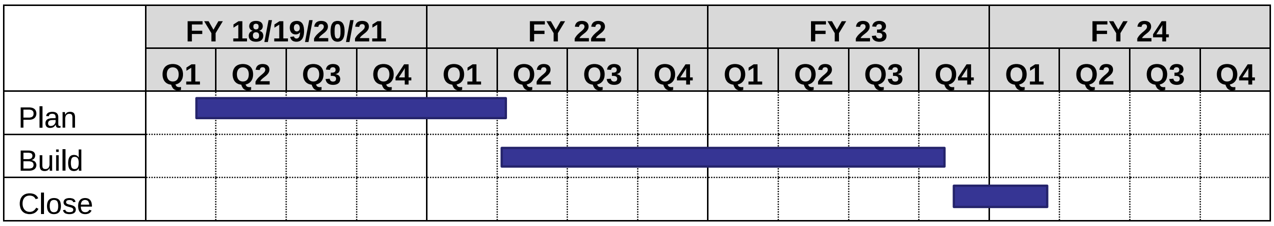
"a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."

As explained in section 3.3.2 above, Option 1 is identified as the preferred option at SLE zone substation because it meets the mandatory requirements of the Amended Bushfire Mitigation Regulations and maximises the net economic benefit compared to the other credible and technically feasible options. It should be noted, however, that the RIT-D project is to achieve compliance at all Tranche three zone substations – and therefore the preferred option at SLE zone substation is one component of the RIT-D project.

The legislated requirement to complete the work does not provide scope to consider delaying the work or to consider alternate project timing.

The proposed timing of work is set out below, noting that FY refers to the period from 1 April to 31 March. The timing may change to address emerging issues and priorities.

Figure 8: Timing of work at SLE



4 Appendix 4 – Benalla Zone Substation REFCL Works

This appendix sets out the proposed scope of work associated with REFCL installation to achieve compliance with the Regulations at Benalla (BN) zone substation. It also discusses the alternative options that were considered.

4.1 Background

BN zone substation is located approximately 210 km north-east of Melbourne at the corner of Mansfield Road and Baddaginnie-Benalla Roads, Benalla. This zone substation was established in the 1940s and supplies 12,134 customers by means of three 10/13 MVA transformers and five distribution feeders. The BN electricity distribution area consists primarily of residential areas in and around the Rural City of Benalla and surrounding areas including Euroa. BN ZS also contains long overhead rural feeders with a total network length of 1,383 km.

The estimated total capacitive current of the BN 22 kV network is 80.9 Amperes (A). As the capacitive current is below 101A, a single REFCL will be required.

4.2 Scope of work

The high level scope of works for this project is summarised below

- Combined 22 kV Switch room / Control Room to house 22 kV Switchboard (comprising of two (2) 22 kV Buses and a Bus-Tie, and associated control protection equipment. The 22 kV switchboard shall be equipped with Zero Sequence (Core Balance) CTs for all feeders, Cap Banks and station service transformers.
- Installation of one (1) Trench REFCL primary equipment, including:
  - **One (1) Arc Suppression Coil (ASC).**
  - **One (1) Residual Current Compensator Inverter (RCC)* Note: provision has been made for an additional ASC, NBK and RCC in General Arrangement of scope document.**
- Retire and replace the existing outdoor air-insulated 22 kV switchgear and all associated 22 kV substation switch bay equipment with two (2) new 22 kV indoor type switchboards.
- Install two (2) 500 kVA 22/0.415kV kiosk type Station Services Transformers.
- Replace nine (9) 22 kV transformer side Surge Arresters (SA), three (3) SAs for each Transformer.
- Install three (3) 22 kV Surge Arresters (SA) at the neutral isolator structures, one (1) SA for each transformer neutral structure.
- Install one (1) Neutral Bus Kiosk (NBK).
- Replace one (1) existing Neutral Earthing Resistor (NER).
- Replace 2x five (5) (10 total) existing support insulators at the base of each Capacitor Bank Reactors.
- Remove three (3) sets of existing Transformer side 22 kV Earthing Switches, and replace with 22 kV support insulators.
- Replace existing Neutral Current Transformers (NCTs) at each Neutral Isolator and install additional two NCTs, total of eight (8) units. NCT mounting members / brackets are to be provided on the existing Neutral Isolator structure to support the new NCTs.
- Replace / install 22 kV cables as follows:

- **Three (3) sets of Transformer 22 kV cable circuits (existing No.1, No.2, and No.3 Transformers), to connect from the respective 22 kV switchboard transformer CB cable box to the corresponding transformer outdoor cable termination structure.**
- **Five (5) sets of 22 kV feeder cable circuits (existing BN1, BN2, BN3, BN4 and BN6 FDRs), to connect from new 22 kV switchboard to their respective cable head pole locations.**
- **One (1) set of 22 kV cable, to connect from new 22 kV switchboard to the cable termination support beside the existing No.1 22 kV Capacitor Bank.**
- **Two (2) sets of 22 kV cable circuits from 22 kV switchboard to the respective Station Services Transformers.**

- Replace / install 22 kV Neutral cables as follows:
  - **from Transformer neutral to Neutral Isolator.**
  - **from Neutral Bus Kiosk to the respective Transformer Neutral Isolator.**
  - **from Neutral Bus Kiosk to the REFCL ASC.**
  - **from Neutral Bus Kiosk to the NER.**
- Install 415V AC supply boards as follows:
  - **One (1) AC 415V REFCL Changeover Board rated for 500 kVA and suitable to supply REFCL equipment.**
  - **One (1) AC 415V Station Services Changeover Board rated for 500 kVA and suitable to supply the station AC supplies.**
- Install switchyard lighting.
- All required primary connections and associated earthing grid connections.
- All required secondary control, protection, communications and SCADA equipment, and associated secondary connections to complete the works.
- Civil and structural works for station equipment above and associated station infrastructure.
- Removal and disposal of redundant equipment and structures.
- Reinstatement of switchyard areas to complete the works.
- AusNet Services will undertake the 22 kV feeder works.
- Noise and firewall engineering studies to be undertaken.
- Earthing assessment.
- AusNet Services will carry out testing for compliance to REFCL requirements for the following:
  - **REFCL testing and REFCL compliant testing as required to complete the works.**
  - **Transformer tests including partial discharge (PD) testing, power transformer condition monitoring tests, and REFCL operational test on each transformer.**
  - **Capacitor bank tests for compliance to REFCL requirements.**

4.3 Options considered

Most of the outdoor switchgear (across 3 buses and 5 feeders) requires replacement to become compatible with REFCL operations. Upgrading the outdoor switchgear is not a viable option as it would result in major outages and customer disruptions.

In addition, the existing site control room at BN ZSS is very compact and does not have the physical space for the required installation of REFCL technology, namely the RCC unit, REFCL control panels, protection and communications updates and modifications and network monitoring and switchgear interface relays. As a result, options need to be measured for the housing of the necessary REFCL technology and associated protection equipment.

Three options have been considered in this assessment as shown in the table below.

Table 17: Options considered

Option	Description Summary
BAU	Business as Usual
1	Install REFCL technology and associated equipment using layout which requires extension of switchyard
2	Install REFCL technology and associated equipment without extension of switchyard

4.3.1 Business as usual

The business as usual option does not allow for the installation of REFCL technology and does not comply with the *Electricity Safety (Bushfire Mitigation) Regulations 2013.* Furthermore, the Victorian Government has amended the *Electricity Safety Act* to include a civil penalties scheme for certain non-compliances with these Regulations. Failure to have the REFCL operating by 1 May 2023 will incur a one-off civil penalty of $4M, and a fine of $5,500 per point for each day the criteria is not met after that date. As a result, this option is not viable and has not been considered further. The costs and benefits of this option are set out in the table below.

Table 18: Costs and benefits of business as usual

Capex and Opex	Not applicable
Community Costs & Benefits	The community serviced by the Benalla zone substation would be exposed to the same level of risk as now of fire starts from 22 kV phase to earth faults in the absence of a REFCL installation. On this basis, the status quo does not maximise net benefits for the community.

4.3.2 Option 1 (preferred option) - Delivery using tilt slab building

This option involves the installation of REFCL technology and associated equipment as well as the 22 kV switchboard within a combined 22 kV control / switch room building of tilt-slab construction. No separate REFCL or control room is required for this option. The benefits of this option are as follows:

a) Minimum footprint area to be developed within the existing substation site.

b) Improved transformer 22 kV cable route for the preferred combined control / switchroom location that is adjacent to the western boundary fence.

c) Consultation and direction from AusNet Services key stakeholders.

d) This is the lowest PV cost option.

For these reasons, this is the recommended option. The costs and benefits of this option are set out in the table below.

Table 19: Costs and benefits of Option 1

Capex and Opex	Capex for the works will incur a direct expenditure of $15,267.1k including management reserve of $849k and Written Down Value (WDV) of $691k. This represents a present value capital cost of $16,174.2k.
Community Costs & Benefits **(Regulated projects)**	Assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the Benalla zone substation will reduce fault energy leading to a decrease in the risk of fire starts from 22 kV single-phase to earth faults.

4.3.3 Option 2 – Delivery using modular buildings

Option 2 involves the installation of REFCL technology and associated equipment as well as the 22 kV switchboard in two new modular switchrooms in addition to one REFCL room and one control room. The installation of two modular urban buildings, along with a REFCL room and a new control room meets the one GFN requirement for the BN ZS, however this presents challenges with space. A larger footprint would be required to be developed within the existing substation and does not support appropriate 22 kV transformer cable routing.

Furthermore, this option also presents a higher capital expenditure cost and is not recommended. The costs and benefits of this option are set out in the table below.

Table 20: Costs and benefits of Option 2

Capex and Opex	Capex installation of a REFCL and station and associated works incurs a direct expenditure of $17,133k including management reserve of $849k and Written Down Value (WDV) of $691k. This represents a present value capital cost of $18,090.1k.
Community Costs & Benefits	Assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013. Safe operation of REFCL technology at the Benalla zone substation will reduce fault energy leading to a decrease in the risk of fire starts from 22 kV single-phase to earth faults.

This option delivers the same benefit as Option 1, but is more expensive and therefore is not the preferred option for BN zone substation.

4.4 Input assumptions and sensitivity analysis

Each option employs a similar mix of capital and operating expenditure, and they also entail similar levels of expected delivery cost risk and involuntary supply interruption costs. Consequently, the ranking of the options will not change by varying these input assumptions. In addition, the ranking of options is also unaffected by changes in the cost of capital.

The timing of the action required to address the identified need is driven by our mandatory bushfire mitigation obligations, and therefore alternate project timings have not been considered.

In view of these considerations, input assumption scenarios and sensitivity analysis are not presented in this report.

4.5 Preferred Option at BN

Clause 5.17.1 (b) of the NER states that the preferred option must:

> *"maximise the present value of the net economic benefit to all those that produce, consume and transport electricity in the National Electricity Market",*

and further that

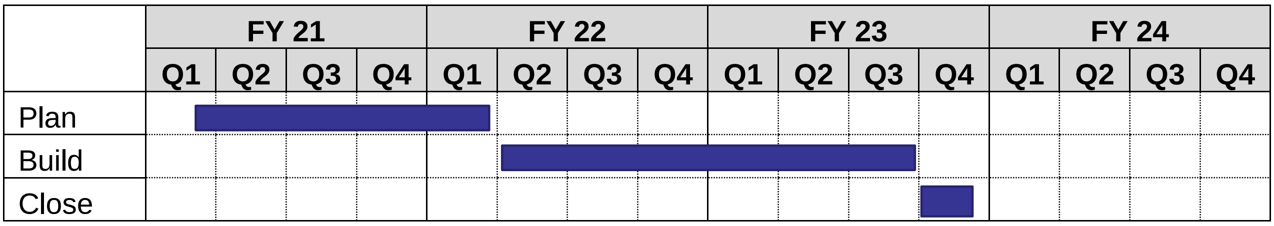
> *"a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."*

As explained in section 4.3.2 above, Option 1 is identified as the preferred option at BN zone substation because it meets the mandatory requirements of the Amended Bushfire Mitigation Regulations and maximises the net economic benefit compared to the other credible and technically feasible options. It should be noted, however, that the RIT-D project is to achieve compliance at all Tranche three zone substations – and therefore the preferred option at BN zone substation is one component of the RIT-D project.

The legislated requirement to complete the work does not provide scope to consider delaying the work or to consider alternate project timing.

The proposed timing of work is set out below, noting that FY refers to the period from 1 April to 31 March. The timing may change to address emerging issues and priorities.

Figure 9: Timing of work at BN



5 Appendix 5 – Kalkallo Zone Substation REFCL Works

This appendix sets out the proposed scope of work associated with REFCL installation to achieve compliance with the Regulations at Kalkallo (KLO) zone substation. It also discusses the alternative options that were considered.

5.1 Background

The Kalkallo (KLO) Zone Substation (ZSS) is a relatively new zone substation and is located on Donnybrook Road near the Hume Freeway in Kalkallo.

KLO ZSS was established in 2010 and supplies approximately 11,500 AusNet Services customers, in Kalkallo, Wallan, Woodstock and Wandong, by means of two (2) 20/33/49.5 MVA transformers and eight (8) 22kV distribution feeders, four (4) underground and four (4) overhead lines. Note: 4 of the 22kV distribution feeders are wholly owned by Jemena and supply Jemena customers.

The peak demand recorded, last summer, for KLO ZSS was 42.3 MVA and the N-1 cyclic rating is 49.1MVA.

5.2 Scope of work

The high level scope of works for this project is summarised below

- One (1) Remote REFCL Substation on KLO14
- One (1) Remote REFCL Substation on KLO24
- Three (3) 5MVA Isolation Transformer Substation on KLO14
- One (1) 3 Phase 300 A Cooper Ground Type Voltage Regulator on KLO14
- One (1) 5MVA Isolation Transformer Substation on KLO24
- 22kV Lines Works on KLO14 & KLO24
  - Reconductoring existing 6.05 km route length of 22 kV 6/0.186 ACSR conductor from Pole 913361 to 912861 with 151 mm2 Covered Aluminium Conductor;
  - Install 14 new sets of standard 22kV Surge Arrestors (SA) and 10-ohm earth. Pole locations need to be determined; and
  - Replace 27 poles with new concrete poles (14/12 C designed for double circuit construction
- Any other minor works to facilitate all the above works.

5.3 Options considered

Several options have been considered by Network Planning Team in consultation with various stakeholders such as Jemena, CSIRO, WSP, ESV, AER, DELWP during development of preferred solutions for this project due to complications involved in this project. Three main options have been considered in this assessment as per table below. The duration of analysis is over 40 years from FY 2020/21 to FY2059/60, based on average regulatory service life of new assets, to be installed under the project.

Most of the replacement works are required for a successful implementation of REFCL technology on KLO with large volume of underground (UG) cables.

Note: significant work has been undertaken, including joint network planning engagements with Jemena, to identify the preferred option of installing remote REFCLs on KLO14 and KLO24 rather than installing REFCLs within the KLO ZSS. Three options have been considered in this assessment as shown in the table below.

Table 21: Options considered

Option	Description Summary
BAU	Business as Usual: No REFCL installation – Not feasible.
1	KLO T3 REFCL Works with proposed REFCL scope
2	KLO T3 REFCL Works with dual feeder (Additional Feeder)

5.3.1 Business as usual

The business as usual option does not allow for the installation of REFCL technology and does not comply with the *Electricity Safety (Bushfire Mitigation) Regulations 2013.* Furthermore, the Victorian Government has amended the *Electricity Safety Act* to include a civil penalties scheme for certain non-compliances with these Regulations. Failure to have the REFCL operating by 1 May 2023 will incur a one-off civil penalty of $6M, and a fine of $5,500 per point for each day the criteria is not met after that date. As a result, this option is not viable and has not been considered further. The costs and benefits of this option are set out in the table below.

Table 22: Costs and benefits of business as usual

Capex and Opex	Not applicable.
Community Costs & Benefits	The community serviced by the KLO zone substation would continue to be exposed to the same level of risk as now of fire starts from 22 kV phase to earth faults in the absence of a REFCL installation. On this basis, the status quo does not maximise net benefits for the community.

5.3.2 Option 1 (preferred) - KLO T3 REFCL Works With Proposed REFCL Scope

This option involves the installation of REFCL technology including remote REFCLs, isolating substations and a regulator at locations on the KLO14 and KLO24 22kV feeders. This option will ensure smooth operation of REFCL technology to reduce the risk of bushfire in Kalkallo area and would continue to maintain current supply reliability to local community/customers, supplied by KLO ZSS.

This option avoids REFCL penalties if delivered by 1 May 2023 and has been scoped to meet regulatory obligations in relation to the ‘required capacity’ performance criteria.

A short summary of the various costs and benefit values from the financial modelling has been provided in the table below. Economic evaluation through the financial modelling has indicated that this option presents a total PV cost of $41.603M and a positive NPV of $6.674M over the modelling period.

As this option provides the lower PV cost, saves the REFCL penalty cost, ensures reliable supply to the Kalkallo community with reduction in bushfire and safety risk; this is the recommended option.

The costs and benefits of this option are set out in the table below.

Table 23: Costs and benefits of Option 1

Capex and Opex	Capex for this option is the delivery budget of $44.588M to be mainly spent between FY2021 and FY2024. LTD expenditure is $322.1k. The total PV of Capex cost is (nominal and discounted) estimated as $41.603M. Opex Cost: No ongoing Opex costs has been considered in this BC. Although there will be some ongoing Opex cost associated with new REFCL equipment starting from FY23/24 which has been excluded from this business case and is assumed to be covered by the REFCL Opex step change included in the EDPR.
Community Costs & Benefits	Considering that community cost and benefits have been calculated as part of the overall REFCL program by the Victorian Government and installation of REFCL technology is a mandatory program, no separate benefit assessment is required. Technology assists in achieving the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013 as amended on 1 May 2016. Safe operation of REFCL technology on the KLO network will reduce fault energy leading to a decrease in the risk of fire starts from 22 kV single-phase to earth faults.

5.3.3 Option 2 – KLO T3 REFCL Works with Dual Feeder (Additional Feeder) option

This option involves the installation of REFCL technology including remote REFCLs, isolating substations and a regulator at locations on the KLO14 and KLO24 22kV feeders, including all required associated components and line works and provides all the benefits similar to preferred option. However, this option also includes replacement of a number of poles to construct a dual circuit – an additional circuit to enhance the capacity for the growing loads in future, supplied by KLO ZSS.

This option avoids REFCL penalties and meets regulatory obligations.

This option provides all the reliability and community benefits, similar to preferred option, with further improvement in terms of future expansion of KLO ZSS and avoids partial re-working of current works.

However, this option requires significantly higher Capex initially, additional $1.13M, without any additional benefits before FY2029. This is mainly due to the reason that the load growth during this period could be managed effectively by installation of a regulator. A regulator is already planned to be installed under this project due to REFCL requirements.

A short summary of the various costs and benefit values from the financial modelling has been provided in the table below. Economic evaluation through the financial modelling has indicated that this option has the higher total PV cost of $42.74M and require significantly higher ($1.13M) delivery budget in comparison to preferred option. As this option requires higher Capex budget and does not provide compensating benefits, this option is not recommended. The costs and benefits of this option are set out in the table below.

Table 24: Costs and benefits of Option 2

Capex and Opex	Capex for this option is the delivery budget of $45.857M to be mainly spent between FY2021 and FY2024. Some of the money ($322.1K) has already been spent since FY20218. The total PV of Capex cost is (nominal and discounted) estimated as $42.736M. Opex Costs: No Opex cost considered similar to preferred option.
Community Costs & Benefits	Same as preferred option.

This option delivers the same benefit as Option 1, but is more expensive and therefore is not the preferred option for KLO zone substation.

5.4 Input assumptions and sensitivity analysis

Each option employs a similar mix of capital and operating expenditure, and they also entail similar levels of expected delivery cost risk and involuntary supply interruption costs. Consequently, the ranking of the options will not change by varying these input assumptions. In addition, the ranking of options is also unaffected by changes in the cost of capital.

The timing of the action required to address the identified need is driven by our mandatory bushfire mitigation obligations, and therefore alternate project timings have not been considered. Note: the preferred solution involved the use of covered conductor for sections of KLO14 and KLO24 which will not be REFCL protected. This is subject to a technical exemption from the Regulations which is being progressed with ESV and the Victorian Government.

In view of these considerations, input assumption scenarios and sensitivity analysis are not presented in this report.

5.5 Preferred Option at KLO

Clause 5.17.1 (b) of the NER states that the preferred option must:

> *“maximise the present value of the net economic benefit to all those that produce, consume and transport electricity in the National Electricity Market”,*

and further that

> *“a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.”*

As explained in section 5.3.2 above, Option 1 is identified as the preferred option at KLO zone substation because it meets the mandatory requirements of the Amended Bushfire Mitigation Regulations and maximises the net economic benefit compared to the other credible and technically feasible options. It should be noted, however, that the RIT-D project is to achieve compliance at all Tranche three zone substations – and therefore the preferred option at KLO zone substation is one component of the RIT-D project.

The legislated requirement to complete the work does not provide scope to consider delaying the work or to consider alternate project timing.

The proposed timing of work is set out below, noting that FY refers to the period from 1 April to 31 March. The timing may change to address emerging issues and priorities.

Figure 10: Timing of work at KLO