Jemena Electricity Networks (Vic) Ltd

Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation

RIT-D Stage 1: Non-Network Options Screening Report

Notice of determination under clause 5.17.4(c) of the National Electricity Rules

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Executive Summary

Jemena Electricity Networks (Vic) Ltd (JEN) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The network service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

Our customers expect us to deliver a reliable electricity supply at the lowest possible cost. To do this, we must choose the most efficient solution to address emerging network issues. This means choosing the solution that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

Identified Need

Under the Electricity Safety Act 1998 (Act) and the Electricity Safety (Bushfire Mitigation) Regulations 2013 (Regulations), JEN is obliged to ensure all 22 kV feeders originating from its Coolaroo Zone Substation (COO) meet certain specified technical performance requirements by 1 May 2023, effectively requiring these feeders to be protected by Rapid Earth Fault Current Limiters (REFCL) or otherwise requiring these feeders to be the subject of exemptions under the Act and Regulations.

In the process of assessing and identifying viable options to provide the most economic and technically feasible solution to maintain the long-term compliance with the Act and Regulations, JEN is also obliged to consider the customer reliability impact (unserved energy) associated with the technical limitations of the REFCL technology, the costs to High Voltage (HV) customers to upgrade their equipment (to enable them to continue to take supply safely from a REFCL protected feeder in accordance with Clause 16 (c) of the Victorian Electricity Distribution Code (VEDC)), and the long-term load growth and associated network augmentation requirements.

Summary of findings

The criteria used to assess the potential credibility of non-network options were:

- Addresses the identified need: by delivering energy to reduce or eliminate the need for investment;
- Technically feasible: there are no constraints or barriers that mean an option cannot be delivered in the context of this investment;
- Commercially feasible: non-network options make commercial sense in terms of delivering a better economic result than the preferred investment; and
- Timely and can be delivered in a timescale that is consistent with the identified need.

Table ES–1 shows the rating scale applied for assessing non-network options.

Table ES–1: Assessment criteria rating

Rating	Colour Coding
Does not meet the criterion	Red
Does not fully meet the criterion (or uncertain)	Amber
Clearly meets the criterion	Green

Table ES–2 shows the initial assessment of non-network options against the Regulatory Investment Test for Distribution (RIT-D) criteria.

Table ES–2: Assessment of non-network options against RIT-D criteria

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and Storage				
1.1 Gas turbine power station				
1.2a Generation using renewables (Solar)				
1.2b Generation using renewables (Wind)				
1.3 Dispatchable generation (large customer)				
1.4 Large customer energy storage				
2.0 Demand Management options				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

JEN has concluded that none of the potential non-network options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. Hence, under National Electricity Rules (NER) clauses 5.17.4(c) and 5.17.4(d), the publication of a non-network options report is not required.

The remainder of this report provides the evidence underpinning the conclusion that a non-network options report is not required.

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Glossary

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Constraint	Refers to a constraint on network power transfers that affects customer service.
Contingency condition (or event)	Refers to the loss or failure of part of the network. An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Contingency probability	The probability that a contingency condition (or event) will occur, and typically approximated by multiplying the number of times a contingency condition occurs (usually in a year) by its duration, normalised by the total available time (in this case, a year).
Energy-at-risk	The total energy at risk of not being supplied if a contingency occurs.
Expected unserved energy (EUSE)	Refers to an estimate of the long-term, probability weighted, average annual energy demanded (by customers) but not supplied. The EUSE measure is transformed into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Jemena Electricity Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 360,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Limitation	Refers to a limitation on a network asset's capacity to transfer power.
Maximum demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Non-network	Refers to anything potentially affecting the transfer of electricity to customers that does not involve the network.
Non-network alternative	A response to growing customer demand that does not involve network augmentation.
Operations & Maintenance expenditure (O&M)	Expenditure (ongoing) for running a product, business or system.
Peak or maximum demand	The highest amount of electrical power delivered (or forecast to be delivered) for a particular period of time.
Probability of exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year:

10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
Probabilistic method	A planning methodology applied to network types with the most significant constraints and associated augmentation costs. It involves estimating the cost of a network limitation with consideration of the likelihood and severity of network outages and operating conditions.
Rapid Earth Fault Current Limiter (REFCL)	Rapid Earth Fault Current Limiter or REFCL means any plant, equipment or technology (excluding neutral earthing resistor) which is: a) designed to reduce the effect of distribution system faults and when operating as intended may lead to a REFCL condition; and b) approved by Energy Safe Victoria in an electricity safety management scheme or bushfire mitigation plan pursuant to the Electricity Safety Act 1998 (Vic).
Regulatory Investment Test for Distribution (RIT-D)	A test administered by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments in the National Electricity Market (NEM).
Reliability corrective action	Reliability corrective action, as defined in the National Electricity Rules, means investment by a Transmission Network Service Provider or a Distribution Network Service Provider in respect of its transmission network or distribution network for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options.
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
Required Capacity	As prescribed by the Electricity Safety (Bushfire Mitigation Duties) Regulations 2018, means that in the event of a phase-to-ground fault on a polyphase electric line, then network must have the ability: • to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and • 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: − 1900 volts within 85 milliseconds; and − 750 volts within 500 milliseconds; and − 250 volts within 2 seconds; and • during diagnostic tests for high impedance faults, to limit: − fault current to 0.5 amps or less; and − the thermal energy on the electric line to a maximum I^2t value of 0.10; where: • high impedance faults means a resistance value in ohms that is equal to twice the nominal phase-to-ground network voltage in volts;

	• I^2t means a measure of the thermal energy associated with the current flow, where I is the current flow in amps and t is the duration of current flow in seconds; • low impedance faults means a resistance value in ohms that is equal to the nominal phase-to-ground network voltage in volts divided by 31.75; and • polyphase electric line means an electric line comprised of more than one phase of electricity with a nominal voltage between 1 kV and 22 kV.
REFCL condition	An operating condition on the 22kV distribution system arising from the proper operation of a REFCL which results in the neutral reference of the distribution system moving to allow the un-faulted Phase to Earth voltage magnitude to approach a value close to the Phase to Phase voltage magnitude. The term “operating condition on the 22kV distribution system‟ in this term extends up to, but not beyond any device or plant which is functionally equivalent to an isolating transformer.
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
value of customer reliability (VCR)	Represents the dollar value customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
zone substation	Refers to the location of transformers, ancillary equipment and other supporting infrastructure that facilitate the electrical supply to a particular zone in the Jemena Electricity Network (JEN).

Abbreviations

Act	Electricity Safety Act 1998
AER	Australian Energy Regulator
BD	Broadmeadows Zone Substation
BMS	Broadmeadows South Zone Substation
Co	Network capacitive current
COO	Coolaroo Zone Substation
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAPR	Distribution Annual Planning Report
DM	Demand Management
EG	Embedded Generation
ESV	Energy Safe Victoria
EUE	Expected Unserved Energy
GVE	Greenvale Zone Substation
HBRA	Hazardous Bushfire Risk Area
HV	High Voltage
JEN	Jemena Electricity Networks (Vic) Ltd
KLO	Kalkallo Zone Substation
kV	Kilo-Volts
LBRA	Low Bushfire Risk Area
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
O&M	Operations and Maintenance
PoE	Probability of Exceedance
REFCL	Rapid Earth Fault Current Limiters
Regulations	Electricity Safety (Bushfire Mitigation) Regulations 2013
RIT-D	Regulatory Investment Test for Distribution
ST	Somerton Zone Substation
VCR	Value of Customer Reliability
VEDC	Victorian Electricity Distribution Code

1. Background

JEN is obliged to comply with Section 120M of the Electricity Safety Act 1998 together with sub-regulation 7(1)(ha) of the Electricity Safety (Bushfire Mitigation) Regulations 2013 for the COO supply area by 1 May 2023.

The Regulations require that each polyphase electric line originating from COO must have the required capacity[1], which includes the following capability 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.*

The obligations also impose significant financial penalties if service performance in accordance with the timetable is not met. The Bushfire Mitigation Civil Penalties Scheme includes financial penalties of up to $2 million per point for any difference between the total number of required substation points prescribed in the Regulations and that actually achieved. The scheme also includes a daily penalty up to $5,500 per point for each day that a contravention with the Regulations continues. COO has been allocated one (1) point in Schedule 2 of the Regulations.

Given the obligations above, JEN developed the network development strategy to address the identified need to comply with bushfire mitigation obligations at COO. As an output from the strategy, JEN plans to install two REFCLs at COO, and undertake various feeder augmentation, reconfiguration and bushfire mitigation activities to achieve the required capacity.

In November 2017, the Australian Energy Regulator (AER) introduced a new requirement that a Regulatory Investment Test (RIT-D) should be undertaken that includes the issue of a non-network options report for those projects greater than $10 million[2] in value where a non-network solution is potentially viable. Distribution businesses are required to go through the RIT-D process to identify the investment option that best addresses an identified need on the network, that is 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 (the preferred option).

The RIT-D applies in circumstances where a network problem (an “identified need”) exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $5 million[3]. As part of the RIT-D process, distribution businesses must also consider non-network options when assessing credible options to address the identified need.

The currently proposed works to comply with bushfire mitigation obligations at COO could be changed in scope or otherwise altered in response to a viable non-network solution. Hence JEN has investigated whether viable non-network solutions exist. Should viable non-network solutions exist, JEN is required to publish a non-network options report and request stakeholder submissions.

[1] Other performance requirements are also specified in the definition of ‘required capacity’ in the Electricity Safety (Bushfire Mitigation) Regulations 2013.

[2] In accordance with the AER Final Application Guidelines RIT-D (14 December 2018), from 1 January 2019 to end of December 2021, this cost threshold will be $11 million. Also see AER, Final determination: Cost thresholds review, November 2018, p.14.

[3] In accordance with the AER Final Application Guidelines RIT-D (14 December 2018), from 1 January 2019 this cost threshold will be $6 million.

1.1 RIT-D Process

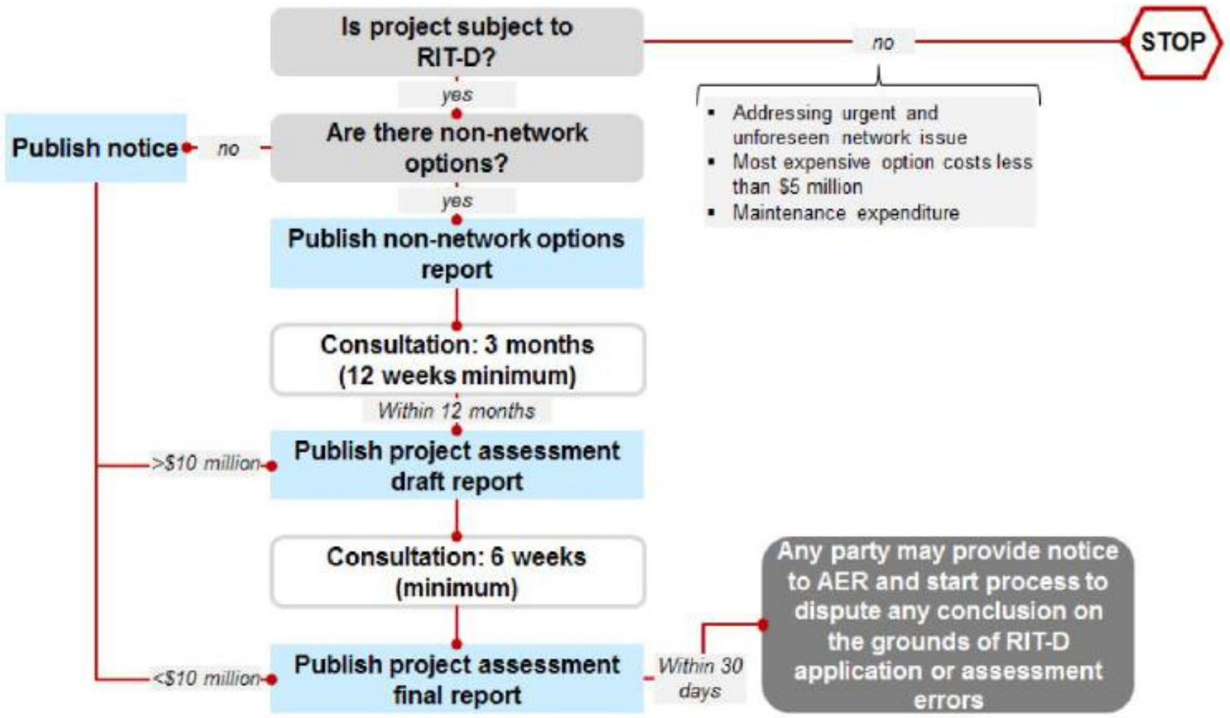
The RIT-D process is summarised in Figure 1–1. This shows that the first step is to screen for non-network options by determining whether they are likely to form:

- A potential credible option(s); or
- A significant part of one or more potential credible options to address the identified need.

This report:

- Summarises the non-network screening requirements and the assessment approach (Section 2)
- Describes the identified need the project is aiming to address (Section 3)
- Describes the network options tested to date (Section 4)
- Assesses the potential of non-network options to help address the identified need (Section 5)
- States the conclusion reached on the need for a non-network options report (Section 6).

Figure 1–1: The RIT-D Process[4]



[4] Source: AER Final Application Guidelines RIT-D (14 December 2018).

2. Screening Requirements and Approach

This section of the report:

- Defines the AER's screening requirements as set out in the documents:
  - *AER-Final Application guidelines RIT-D - December 2018* (https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018);
  - NER Version 161 (https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current).
- Describes the approach to assessing the credibility of non-network options.

2.1 Definitions

Non-network options include (AER's Application Guidelines Section 6.1):

- Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or Smart meters and associated cost-reflective pricing);
- Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators or using energy storage systems and load transfer capacity).

An identified need is defined in Chapter 10 of the NER as the objective a Network Service Provider (NSP) seeks to achieve by investing in the network.

According to the AER's Application Guidelines (Section 3.1), an identified need may be addressed by either a network or a non-network option and:

- May consist of an increase in the sum of consumer and producer surplus in the NEM, or an identified need may be for reliability corrective action as per NER 5.17.1(b), where the NER 5.10.2 defines reliability corrective action as a NSP investment in its network to meet the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options.
- RIT-D proponents should express an identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. This objective should be expressed as a proposal to electricity consumers and be clearly stated and defined in the RIT-D report. Framing the identified need as a proposal to consumers should assist the RIT-D proponent in demonstrating why the benefits to consumer would outweigh the costs. A description of an identified need should not mention or explain a particular method, mechanism or approach to achieve a desired outcome.

A credible option is defined in Clause 5.15.2(a) of the NER as an option, or group of options that:

- Addresses (or address) the identified need;
- Is (or are) commercially and technically feasible; and
- Can be implemented in sufficient time to meet the identified need.

NER Clause 5.15.2(c) conveys that: In applying the regulatory investment test for distribution, the RIT-D proponent must consider all options that could be reasonably classified as credible options without bias to:

- Energy source;
- Technology;
- Ownership; and
- Whether it is a network or non-network option.

JEN have interpreted the guidance to mean that a credible option could also consist of a non-network component and a network component which combined meet the identified need. For example, where a non-network solution reduces peak demand so that the RIT-D proponent can install smaller capacity or less costly equipment (AER's Application Guidelines Example 22, page 73).

2.2 Approach

JEN's approach to assessing the credibility of potential non-network options includes:

- Describing the identified need being addressed by this project including the condition issues driving the proposed investment and the capacity, demand and the minimum contribution required if non-network options are to be potentially credible;
- Describing the network options considered together with a preliminary designation of the preferred network solution;
- Documenting the initial assessment of the full range of non-network options against the criteria in Clause 5.15.2(a) of the NER (defined in Section 2.1);
- Concluding whether there is sufficient and appropriate evidence to determine that there are no non-network options that are potential credible options and identifying any issues that require further examination.

3. Identified Need and Project Objectives

JEN has prepared this non-network screening report to assess whether compliance with the bushfire mitigation obligations at COO could be achieved either fully, or in part through non-network options. To assess whether the non-network options could be beneficial, it is important firstly to define the identified need for this location.

JEN has identified the COO and distribution network as a priority for investment based on one key need:

- The need to comply with the regulatory obligations and avoid financial penalties (Compliance). These regulatory obligations are driven by the need to protect the public from harm caused by bushfires ignited by the distribution network (Safety).

JEN must also ensure that the safety and reliability of the electricity distribution network is not compromised as a result of actions taken to meet this identified need.

This non-network screening report is based on the supply area which is subject to the Regulation, i.e. all feeders supplied from COO under system normal conditions at the time the Regulations came into effect (1 May 2016), and the needs identified for that network.

3.1 Safety and Compliance

Bushfires ignited by powerlines contributed to the devastating 2009 Black Saturday bushfires. In the ensuing Royal Commission, REFCLs have been demonstrated to be capable of preventing faulted 22kV powerlines from starting fires. Subsequently, the Victorian Government has mandated REFCL protection of the COO 22kV feeders through amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2013.

3.1.1 Act and Regulations

Following the 2009 Black Saturday bushfires, the State Government of Victoria established the 2009 Victorian Bushfires Royal Commission (Royal Commission) to investigate the causes and responses to the bushfires. In its July 2010 Final Report, the Royal Commission concluded that five of the major fires that it investigated were started by power lines. The Royal Commission made 67 recommendations, of which eight (Recommendations 27 to 34) related to reducing the likelihood of power lines starting catastrophic bushfires.

The Powerline Bushfire Safety Taskforce (PBST) was established in August 2010 to recommend to the Victorian Government how to maximise the value to Victorians from the Royal Commission recommendations. The PBST presented its final report to the Victorian Government on 30 September 2011. The Victorian Government accepted PBST's recommendations and in December 2011 announced a package of initiatives. Among these initiatives was a rollout of REFCLs in selected zone substations prone to bushfire start risk, subject to further trials on a real network to confirm their effectiveness in reducing fire risk.

REFCLs have the capability to reduce the risk of bushfire starts from lines which experience a phase to earth fault. They reduce the current in any one phase which experiences an earth fault. As the devices act in milliseconds, without the need for human intervention, they are designed to reduce customer supply interruptions and reduce the risk of starting a fire.

The REFCL fire ignition test project initiated by the Department of State Development Business and Innovation (DSDBI) and conducted in 2014, confirmed that the REFCL technology reduces the fire ignition risk associated with bare-wire overhead power lines. Current regulations have mandated the installation of REFCL technology with prescribed earth fault protection sensitivity described as the 'required capacity', at selected zone substations supplying into areas with extreme fire risk consequence. The Regulations came into operation on 1 May 2016.

JEN is obliged to comply with Section 120M of the Electricity Safety Act 1998 together with sub-regulation 7(1)(ha) of the Electricity Safety (Bushfire Mitigation) Regulations 2013 for the COO supply area by 1 May 2023.

The Victorian Government also introduced significant financial penalties if service performance in accordance with the timetable is not met. The Bushfire Mitigation Civil Penalties Scheme includes financial penalties of up to $2 million per point for any difference between the total number of required substation points prescribed in the Regulations and that actually achieved. The scheme also includes a daily penalty up to $5,500 per point for each day that a contravention with the Regulations continues. COO has been allocated one (1) point in Schedule 2 of the Regulations.

Provision has been made in the Act and Regulations for JEN to seek exemptions for sections of the network. Applying for exemptions are only feasible where bushfire ignition risk can be proven to be neutral compared to REFCL protection of these sections (e.g. underground cables or other forms of bushfire mitigation), and cost of compliance is high.

3.1.2 Rapid Earth Fault Current Limiters

'Required capacity' means that, in the event of a phase-to-ground fault on a polyphase electric line, then network must have the ability:

- to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and
- 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:
  - 1900 volts within 85 milliseconds; and
  - 750 volts within 500 milliseconds; and
  - 250 volts within 2 seconds; and
- during diagnostic tests for high impedance faults, to limit:
  - fault current to 0.5 amps or less; and
  - the thermal energy on the electric line to a maximum I^2t value of 0.10;

where:

- high impedance faults means a resistance value in ohms that is equal to twice the nominal phase-to-ground network voltage in volts;
- I^2t means a measure of the thermal energy associated with the current flow, where I is the current flow in amps and t is the duration of current flow in seconds;
- low impedance faults means a resistance value in ohms that is equal to the nominal phase-to-ground network voltage in volts divided by 31.75; and
- polyphase electric line means an electric line comprised of more than one phase of electricity with a nominal voltage between 1 kV and 22 kV.

In practical terms, generally, these performance requirements can only be achieved through the installation of REFCLs. REFCLs consist of four main components; an Arc Suppression Coil, Residual Current Compensator, Grid Balancing Unit and Control System.

In addition, the following works are required on the 22kV feeders:

- feeder augmentation/reconfiguration to maintain each REFCL within its capacitive current limit, i.e. a maximum of 80A per 22kV feeder, 100A per bus and 200A per zone substation, and to maintain reliability of supply to homes and businesses;
- network capacitive balancing of single phase (two-wire) spurs to facilitate correct REFCL operation, which includes installations of capacitor banks, third phase wires and re-phasing of some sections;

- line hardening to withstand the increased voltages on the non-faulted phases during REFCL operation, which includes the replacement of surge arrestors and some sections of underground cable with higher rated equipment; and
- replacement of some network equipment to be compatible with REFCL protected networks, including automatic circuit reclosers (ACRs), voltage regulators and sectionalisers.

3.1.3 Other considerations

In addition to achieving the required capacity for COO, the following must also be taken into consideration:

- The level of reliability in the COO supply area must be maintained and managed in light of the REFCL technical limitations;
- Long-term load growth must be considered and catered for. In essence, the proposed solution needs to align with the network growth strategy;
- Lifecycle cost, including both the upfront cost of compliance and the ongoing cost of maintaining and operating the network; and
- The cost to HV customers of hardening their installations to withstand the increased voltages during REFCL operation in accordance with Clause 16(c)[5] of VEDC.

3.1.4 Probabilistic Economic Planning

In accordance with clause 5.17.1(b) of the NER, JEN's augmentation investment decisions aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

To achieve this objective, JEN applies a probabilistic planning methodology that considers the likelihood and severity of critical network conditions and outages. The methodology compares the forecast cost to consumers of losing energy supply (e.g. when there is a feeder outage and it can't be transferred to an adjacent feeder due to the REFCL technical limitations) against the proposed augmentation cost to mitigate the energy supply risk. The annual cost to consumers is calculated by multiplying the expected unserved energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the value of customer reliability (VCR). This expected benefit is then compared with the costs of the feasible options.

In essence, the total cost for each option includes the following:

- Project cost to comply with the Act and Regulations by 1 May 2023;
- Annual on-going operating and maintenance expenditure (O&M) to maintain compliance;
- Present value of the annual cost of expected unserved energy over 10-year period; and
- HV customer costs to comply with the Act and Regulations by 1 May 2023.

As this strategy is developed to meet the safety regulation as the primary focus, future network augmentation costs due to load growth under each option have not been specifically quantified, however the impacts of load growth are factored into the annual cost of expected unserved energy considered in our analysis.

All options considered would result in the same bushfire risk-neutral safety outcome. Therefore, the option that has the least overall cost would be considered to be the option that maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM.

[5] Clause 16 (c) of VEDC states that "*A **business customer** must take reasonable precautions to minimise the risk of loss or damage to any equipment, premises or business of the **business customer** which may result from poor quality or reliability of electricity **supply** or the **distribution system** operating under the **REFCL condition** in accordance with clause 4.2.2A*"

3.1.5 COO supply area

COO is located in the North Growth Corridor[6] of Melbourne and supplies a mix of high density urban and low density rural areas. Based on the bushfire risk rating of the COO supply area at the time the Regulations came into effect, the COO has been designated as a one (1) point zone substation in the Electricity Safety (Bushfire Mitigation) Regulations 2013.

The urban areas supplied by COO are expected to continue to grow towards the urban growth boundary, while the rural areas supplied by COO are expected to experience low levels of growth in the short to medium term. JEN's overall REFCL strategy must not inhibit this future network topology.

COO is a two-transformer zone substation with 6 feeders, the network capacitance (Co) of each are as tabulated in Table 3-1 below.

Table 3-1: Co of COO 22 kV feeders subject to the REFCL regulation (2019)

Feeder	Co (A)	Underground (km)	Overhead (km)	Comments
COO-11	105	36.7	133.3	Exceeds maximum feeder Co of 80A.
COO-12	2	0.5	0.3	
COO-13	52	11.4	3.9	
COO-14	51	16.5	1.4	
COO-21	45	13.5	17.1	
COO-22	65	21.2	0.7	
TOTAL	**320**	**99.8**	**156.7**	Exceeds maximum zone substation Co of 200A

The capacitive current on COO-11, COO bus #1 and the COO total exceeds the limitation of the REFCL technology currently available. The capacitive current on COO is expected to continue to grow due to the ongoing development of underground residential estates in the urban parts of the COO supply area.

In the rural parts of the COO supply area, there are a number of existing single phase spurs. These sections are required to be balanced to ensure correct operation of the REFCL. Some existing equipment on the COO feeders must also be replaced for compatibility with REFCL.

COO supply area is bordered by non-REFCL zone substations AW and BD to the south, SBY to the west, ST to the east and AusNet's REFCL zone substation KLO to the north. Sections of the network may be transferred to adjacent zone substations temporarily during a planned or unplanned outage, or permanently in response to load growth. The REFCL project must ensure all network assets are maintained within their safe loading limits, and maintain the reliability of the network. Where existing transfers between REFCL and non-REFCL networks are no longer technically feasible due to installation of the REFCL, e.g. due to capacitive current limits or the requirement for network hardening and balancing, the probability and consequence of a supply outage must be assessed and network augmentation or exemption may be required.

3.1.6 Credible Solution Requirements

The Regulations require each polyphase electric line originating from COO to comply with the performance standards specified in the Regulations by 1 May 2023. The network-specific nature of this performance standard is such that it cannot be met by a non-network option, such as an embedded generator or demand side response. The installation of REFCLs is the only technically feasible solution currently available that is capable of satisfying the performance requirements specified in the Regulations. Therefore, there are no credible non-network options

[6] Refer to "Growth Corridor Plans – Managing Melbourne's Growth" available at https://vpa.vic.gov.au/greenfield/growth-corridor-plans/

to address the identified need, which is to comply with the Regulations ('reliability corrective action' as defined in the NER).

4. Network options

Recognising the interrelationships between COO and KLO, in 2019, JEN and AusNet Services engaged the consultant WSP to assist in a joint planning exercise to examine a number of technical design options and determine the most efficient cost of meeting the requirements of the Act and Regulations across both COO and KLO supply areas over the long-term. This exercise identified 26 options. Through this process, we identified that there was only one option (Option 15) which did not require any exemptions from the requirements of the Act and Regulations. However this option involved significantly higher expenditure than other options due to significant technical limitations of the REFCL technology.

For the reasons identified above, JEN has investigated alternative solutions to the installation of a REFCL at COO and proposed an approach which will result in a level of residual bushfire risk that we consider is commensurate with that which was originally intended by the Act and Regulations, but at a lower cost to customers than if no exemptions to the Act or Regulations were granted. We considered that such alternative options would likely be more preferable in customers' long-term interests than Option 15 described above.

Based on the outputs of previous joint planning report[7] prepared by the engineering consultant WSP in December 2019 (and published as part of JEN's regulatory proposal on 31 January 2020), and further works undertaken by JEN since then, JEN identified Option 27 as the preferred option in its initial network development strategy[8] prepared in late November 2020.

Consistent with the recommendation to implement Option 27, JEN progressed the actions necessary to procure the land required for a new zone substation in the Greenvale area. However, sale of land negotiations have stalled and the procurement is now unlikely to be able to be completed within a timeframe which would allow for JEN to use Option 27 to achieve compliance with the Act and Regulations by 1 May 2023. As Option 27 would not meet the identified need of allowing JEN to comply with its obligations under the Act and Regulations by 1 May 2023, JEN considers this option to be no longer technically feasible. JEN has therefore developed an alternative solution (referred to in this paper as Option 28) involving a conceptually similar REFCL solution, network layout and strategy and associated mitigation works to Option 27 while avoiding the need to procure land in the Greenvale area.

JEN's revised network development strategy[8] prepared in January 2021 assesses Option 28 against the four options[9] previously considered to determine the option that maximises net market benefits, noting that each option provides a commensurate level of bushfire risk mitigation:

- Option 7 – Install Isolation Transformers on Underground Feeders and REFCLs at COO;
- Option 11 – Install REFCLs at COO;
- Option 15 – Two REFCL Zone Substations in JEN;
- Option 27 – Build a New REFCL Zone Substation ('GVE'); and
- Option 28 – Install Two REFCLs at COO Under a Split Bus Configuration with One High Performance REFCL.

4.1 Assessment Assumptions

In evaluating net economic benefits, the following assumptions were used to calculate the annualised value of expected unserved energy (EUE) for all the options analysed in this paper:

- VCR of $41,738 per MWh;

7 Refer to "Economic Options to Maintain REFCL Compliance at Kalkallo and Coolaroo Zone Substations, Joint Planning Report, December 2019" report.

8 Refer to 2021-26 Electricity Distribution Price Review Revised Proposal Attachment 04-03 "Network Development Strategy - Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation", available from https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26/revised-proposal

9 Options 7, 11 and 15 are extracted from "Economic Options to Maintain REFCL Compliance at Kalkallo and Coolaroo Zone Substations, Joint Planning Report, December 2019" report, and re-produced in this document for information that are relevant to JEN only.

- Average feeder outage rate is calculated based on JEN historic data;
- Average feeder outage repair time (or supply restoration time) for underground assets is 8 hours and overhead assets is 4 hours;
- Average feeder operational response time to perform load transfers to adjacent feeders is 1 hour;
- Feeder average demand is used to determine expected unserved energy at risk for a feeder outage that cannot be transferred to adjacent feeders due to REFCL technical limitations;
- Feeder load factor of 0.55 is assumed;
- Net Present Value (NPV) is calculated over 10 years, using a real discount rate of 2.5%;
- For the single radial COO-VCO-GVE 66kV line (under option 27):
  - Sub-transmission line outage frequency, which is 0.1 outages per kilometre of line length per year;
  - Sub-transmission line outage average duration of 6 hours per outage; and
  - With approximately 7km in line length, this equates to 0.7 outages per annum lasting an average duration of 6 hours (resulting in the loss of all load at GVE for that time).
- Options 7, 11 and 15 have the same assessment outcomes in terms of technical feasibility, compliance, risk and costs as documented in the "AusNet Services and Jemena Electricity Networks, Economic Options to Maintain REFCL Compliance at Kalkallo and Coolaroo Zone Substations, Joint Planning Report, December 2019" report;
- Option 27 is no longer technically feasible due to the unavailability of the land required to proceed with this option in a timeframe which would enable compliance with the Act and Regulations; and
- Option 28 is technically feasible, is compliant with the Act and Regulations, and results in an acceptable risk outcome (bushfire risk-neutral outcome).

4.2 Options Assessment

JEN's options assessment considered the project and ongoing operational costs, HV customer costs to comply, forecast load, network capacity and reliability (unserved energy). Refer to 2021-26 Electricity Distribution Price Review Revised Proposal Attachment 04-03 "Network Development Strategy - Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation"[10] for further details.

A summary of the NPV cost analysis assessed for each option is presented in Table 4-1.

Table 4-1: Summary of NPV Cost Analysis (real, $2020)

Option	NPV of Project Cost ($M)	NPV of O&M ($M)	NPV of Cost of Expected Unserved Energy ($M)	NPV of HV Customer Cost ($M)	NPV of Total Costs ($M)	Ranking
Option 7	25.8	2.2	60.8	9.1	97.8	4
Option 11	23.6	2.2	60.2	9.1	95.1	3
Option 15	49.5	2.2	12.9	9.1	73.7	2

[10] 2021-26 Electricity Distribution Price Review Revised Proposal Attachment 04-03 "Network Development Strategy - Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation" is available from https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26/revised-proposal

Option	NPV of Project Cost ($M)	NPV of O&M ($M)	NPV of Cost of Expected Unserved Energy ($M)	NPV of HV Customer Cost ($M)	NPV of Total Costs ($M)	Ranking
Option 27	35.2[11]	2.2	20.7	1.3	59.3	N/A (no longer feasible)
Option 28	34.8[12]	2.2	12.9	9.1	59.0	1

4.3 Preferred Option

The assessment shows that the preferred solution is Option 28, as by representing the lowest total cost, this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM.

Option 28 includes the following works:

- Install two REFCLs at COO under a split bus configuration—that is, one REFCL on COO Transformer No.1 with high performance settings to meet the Required Capacity, and one REFCL on COO Transformer No.2 with base performance settings which will be operated below the Required Capacity, with the 22kV bus tie CB normally open. This arrangement will ensure the station will operate correctly by reducing the earth fault current on the COO Transformer No.2 side to a sufficiently low level that will avoid an inadvertent tripping of COO Transformer No.1 side[13];
- Transfer those sections of the existing COO 22kV network with high bushfire risk, mainly COO-011, to COO Transformer No.1 (high performance REFCL)—thereby providing REFCL protection to those 22kV feeders in compliance with the Act and Regulations. The remaining sections of COO supply area will be transferred to COO Transformer No. 2 (base performance REFCL) and neighbouring non-REFCL Broadmeadows Zone Substation (BD) to reduce the capacitance level to within acceptable design level on the base performance REFCL; and
- Undertake various bushfire mitigation activities to reduce the bushfire risk for those polyphase electric lines of an overhead construction within an urban environment that pose some risk to a fire ignition that could propagate to a bushfire—therefore resulting in a bushfire risk-neutral outcome—and obtain exemptions under the Act and Regulations in respect of these lines.[14]

Option 28 provides a bushfire risk-neutral outcome when compared to Option 15.

JEN had previously lodged its exemption applications in May 2020 to both the Energy Safe Victoria (ESV) and Department of Environment, Land, Water and Planning based on the envisaged Option 27 solution, and the exemptions from the Act and Regulations have been granted in November 2020, with associated conditions requiring mitigation works to be undertaken. Following discussions with ESV in December 2020, it is likely that the granted exemptions published in the Government Gazette remain valid for this proposed Option 28 as this

11 Project cost for option 27 is $37.3M (real, $2021).

12 Project cost for option 28 is $36.9M (real, $2021).

13 The presence of the base performance REFCL on COO Transformer No.2, in lieu of Neutral Earthing Resistor, mitigates technical limitation of the device associated with the shared earth at the zone substation, which would prevent the required high performance operation on the COO Transformer No.1 side from inadvertent tripping due to stray capacitance if only one REFCL were installed. The base performance REFCL reduces earth fault current from approximately 1,500A (under Neutral Earthing Resistor operation) to less than 100A.

14 This entails exemption of all underground cables and overhead conductors within an urban environment supplied by COO and the requirement that JEN undertakes various bushfire mitigation activities for the remaining overhead conductors (supplied by COO) that pose some risk to a fire ignition that could propagate to a bushfire. Additionally, JEN would rely on exemptions already granted under the Act and Regulations in respect of polyphase electric lines which are of a fully underground construction.

solution involves a conceptually similar REFCL solution, network layout and strategy and associated mitigation works to Option 27. JEN is currently working with ESV to confirm this position.

The JEN capital expenditure required for the recommended solution is $36.9M (real $2021, including overheads).

5. Assessment of non-network options

Potential non-network options that could meet the project objectives (as envisaged in the AER RIT-D application guidelines Section 6.1) are listed below:

- Demand Management (DM) - Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or demand response arrangements with customers)
- Embedded Generation (EG) - Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators or using energy storage systems and load transfer capacity)

5.1 Credible Scenarios

The aim is to test whether a non-network option (or combination of non-network measures) is a viable way to avoid or reduce the scale of a network investment in a way that addresses the identified need. A non-network option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

Potential non-network scenarios are:

1. Meeting the identified need in its entirety through a non-network option
2. Installing some network assets and meeting the remaining need through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting the identified need to comply with the Regulations and achieve the required capacity on the 22kV lines originating from COO.

The non-network screening criteria is applied in the next section with these generation requirements or savings in mind.

5.2 Non-network Assessment Overview

This section reports on the credibility of potential non-network options as alternatives or supplements for the REFCL works. The criteria used to assess the potential credibility was:

1. **Addresses the identified need:** by delivering energy to reduce or eliminate the need for the investment
2. **Technically feasible:** there are no constraints or barriers that mean an option cannot be delivered in the context of this investment
3. **Commercially feasible:** non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment
4. **Timely** and can be delivered in a timescale that is consistent with the identified need.

Figure 5–1 shows the rating scale applied for assessing non-network options.

Figure 5–1: Assessment Criteria Rating

Rating	Colour Coding
Does not meet the criterion	
Does not fully meet the criterion (or uncertain)	
Clearly meets the criterion	

The assessment has also considered whether a non-network option (or combination of non-network measures) is a viable way to avoid or reduce the scale of a network investment in a way that meets the identified need. A non-network option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

Figure 5–2 shows the initial assessment of non-network options against the RIT-D criteria. The assessment did not find any of the non-network options to be potentially credible against RIT-D criteria (considered both in insolation, and in combination with network solutions). The assessment commentary for each of the generation and storage options is set out in the following sections.

Figure 5–2: Assessment of Non-network options against RIT-D criteria

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and Storage				
1.1 Gas turbine power station				
1.2a Generation using renewables (Solar)				
1.2b Generation using renewables (Wind)				
1.3 Dispatchable generation (large customer)				
1.4 Large customer energy storage				
2.0 Demand Management options				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

5.3 Non-network assessment commentary

JEN has determined that no non-network option is potentially credible, or that forms a significant part of a potential credible option, for the RIT-D project to address the identified need.

The reasons for this determination are:

1. The network-specific nature of this performance standard is such that it cannot be met by a non-network option, such as an embedded generator or a demand-side response. The installation of REFCLs is the only technically feasible solution currently available that is capable of satisfying the performance requirements specified in the Regulations;

2. The proposed capital works on JEN's electricity distribution network is required to ensure that REFCL operation does not compromise the safety and reliability of the network; and

3. 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 Rules requirements, we note that these reasons are not dependent on any particular assumptions or methodologies.

6. Conclusions and next steps

6.1 Conclusion

In conclusion, the evidence shows that none of the non-network options are potential credible options to meet the identified need.

In addition, the analysis demonstrates that there are no combinations of non-network options, or non-network and network options, that are likely to adequately meet the criteria that would necessitate the production of a non-network options report.

This document is JEN’s notice of determination under clause 5.17.4(c) of the NER.

6.2 Next steps

JEN will prepare a Draft Project Assessment Report (DPAR) which will present a detailed assessment of all credible network options to address the identified need. In accordance with clause 5.17.4 of the NER, JEN intends to publish the DPAR for consultation by 30 June 2021.