Notice of Determination Report (East Malvern Zone Substation Switchboard and Secondary Assets Condition)

Project No. UE-RSA-N-24-001

united energy

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1. Executive Summary

1.1 Summary

United Energy (UE) is a regulated Victorian electricity distribution business. UE distributes electricity to more than 727,000 customers across Melbourne's east and south-east metropolitan area, and the Mornington Peninsula. The UE network consists of more than 215,000 poles and over 13,590 kilometres of overhead lines and underground cables. Electricity is received via 92 sub-transmission lines at 47 zone substations, where it is transformed from sub-transmission voltages down to distribution voltages.

The area of the UE network that is the subject of this Regulatory Investment Test for Distribution (RIT-D) is the East Malvern Zone Substation (EM) supply area (i.e. EM supply area) that includes parts of the suburbs of Chadstone, Alamein, Carnegie and East Malvern. EM is owned and operated by UE, providing power to approximately 14,234 customers, with a mix of residential and commercial loads.

The condition of the 11 kV indoor switchboard and secondary assets (protection, control, monitoring and communications equipment) at EM, necessary for the provision of a safe and reliable power supply to customers within the EM supply area, is deteriorating. Most of these assets at EM are now technically obsolete, being unsupported by equipment suppliers, with no spares.

UE has identified potential credible network options to address the switchboard and secondary asset condition risks at EM, and investigated whether viable non-network or stand-alone power system (SAPS) solutions exist as alternatives to, or supplements for the network options.

Based on this report, UE has concluded on reasonable grounds, that none of the potential non-network or SAPS options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network or SAPS options adequately address the identified need. Therefore, UE has determined that the publication of, and the consultation on an options screening report, is not required in this instance.

1.2 Purpose

This Notice of Determination report has been prepared by UE in accordance with the requirements of clause 5.17.4, paragraphs (c) and (d) of the National Electricity Rules (NER) version 209. UE is normally required to publish an options screening report and request stakeholder submissions, as detailed in NER clause 5.17.4(e). However, in the event that there are no potential credible non-network or SAPS options (or any combination of those options with or without a network option) that could address the identified need, UE is instead required to publish a Notice of Determination.

1.3 The Identified Need

The condition of the 11 kV indoor switchboard and secondary assets at EM is deteriorating. In particular,

- The condition of the 11 kV switchboard at EM is deteriorating. Being of type Reyrolle LMT, it is an oil-insulated non-arc-fault-contained switchboard, installed in 1961. This switchboard is 63 years old and its condition poses a safety and reliability risk. As the switchboard predates current standards, any internal arc fault will not be contained and would be expelled into the switch-room, which poses a safety risk to assets and personnel.
- Many of the protection and control relays at EM are now technically obsolete, being no longer supported by the vendor, and limited spares. This includes obsolete Siemens Siprotec-4 relays which have had several failures, including four failures since 2019. A recent relay failure took six months to be repaired due to limited manufacturer support.

Therefore, the identified need is to manage the increasing risk of asset failure to maintain safety and reliability of electricity supply to UE's customers and workforce within the EM supply area.

1.4 Next Steps

UE is not required to publish and consult on an options screening report in this instance, because it has been determined on reasonable grounds, that there will not be a potential credible non-network or SAPS option that is able to address the identified need, nor any that forms a significant part of a potential credible option.

Furthermore, the total cost of the most expensive credible network option to address the identified need, is less than the trigger threshold of $12 million[1] for the publication of and consultation on a Draft Project Assessment Report (DPAR).

On this basis, UE shall now prepare and publish a Final Project Assessment Report (FPAR), as required under NER clause 5.17.4, paragraphs (o) to (s). UE intends to publish the FPAR by 31st May 2024.

For the purposes of referencing this RIT-D, this RIT-D is referred to as the "*East Malvern Zone Substation Switchboard and Secondary Assets Condition*" identified need.

2. Introduction

This Notice of Determination report has been prepared by United Energy (UE) in accordance with the requirements of clause 5.17.4, paragraphs (c) and (d) of the National Electricity Rules (NER) version 209, for the East Malvern Zone Substation Switchboard and Secondary Assets Condition identified need.

UE is not required to publish and consult on an options screening report in this instance, because it has been determined (on reasonable grounds) that there will not be a potential credible non-network or SAPS option that is able to address the identified need, nor any that forms a significant part of a potential credible option.

This report sets out the reasons for this determination, including the methods and assumptions used in making the determination.

The need for investment and the possible options for addressing the East Malvern Zone Substation Switchboard and Secondary Assets Condition identified need, have been foreshadowed in UE's 2023 Distribution Annual Planning Report (DAPR).[2]

This Notice of Determination report:

- Provides background information on the network limitations at East Malvern Zone Substation (EM), and for the EM supply area for which it services.
- Identifies the need which UE is seeking to address, together with the assumptions used in identifying that need.
- Describes the credible options that UE currently considers may address the identified need, including for each:
  - Technical definitions;
  - The risk costs associated with the option for addressing the identified need;
  - The estimated commissioning date; and
  - The total indicative cost (including capital and operating costs), with high-level cost breakdown.
- Sets out the technical characteristics that a non-network or stand-alone power system (SAPS) option would be required to deliver in order to address the identified need.

3. Referenced Documents

Table 1: Referenced Documents

Title	Document No.
UE Embedded Generation Network Access Standards	UE-ST-2008.X
UE Asset Risk Quantification Guide	UE-GU-2011

[1] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

[2] UE: Distribution Annual Planning Report. Available at: https://dapr.unitedenergy.com.au/ue_data/UE-PL-2209%20Distribution%20Annual%20Planning%20Report%20DAPR%20-%202023.pdf

4. Definitions

Table 2: Terms and Definitions

Term	Definition
A.C.	Alternating Current
AEMO	Australian Energy Market Operator
AFAP	As Far As Practicable
CFD	Caulfield Zone Substation
DAPR	Distribution Annual Planning Report
D.C.	Direct Current
DPAR	Draft Project Assessment Report
DSED	Demand Side Engagement Document
EM	East Malvern Zone Substation
EUE	Expected Unserved Energy (MWh pa)
FPAR	Final Project Assessment Report
MWp	Megawatt peak
K	Gardiner Zone Substation
NCC	Network Control Centre
NEM	National Electricity Market
NER	National Electricity Rules
OR	Ormond Zone Substation
PoE	Probability of Exceedance
RIT-D	Regulatory Investment Test for Distribution
RTU	Remote Terminal Unit
SAPS	Standalone Power System
SCADA	Supervisory Control and Data Acquisition
UE	United Energy
VCR	Value of Customer Reliability ($/MWh)
50% PoE	The forecast maximum demand has a 50% probability of exceedance (PoE). That is, the forecast maximum demand is expected, on average, to be exceeded once in two years.
10% PoE	The forecast maximum demand has a 10% probability of exceedance (PoE). That is, the forecast maximum demand is expected, on average, to be exceeded once in ten years.
Credible option	An option that addresses the ‘identified need’, is commercially and technically feasible, and can be implemented in sufficient time to meet the ‘identified need’.
Identified need	Any capacity, voltage, or safety limitation on the distribution system.
Limitation	Any limitations on the operation of the distribution system that will give rise to Expected Unserved Energy or safety risk consequences.
Network option	A means by which an ‘identified need’ can be fully or partly addressed by expenditure on distribution network assets.
Non-network or SAPS option	A means by which an ‘identified need’ can be fully or partially addressed other than by a network option.
Non-network service provider	A party who provides a non-network or SAPS option.

Term	Definition
Potential credible option	An option has the potential to be a credible option based on an initial assessment of its ability to address the 'identified need'.
Preferred network option	A credible network option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred network option can be a network option, or do nothing (i.e. status quo).
Preferred option	A credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred option can be a network option, non-network or SAPS option, combination of both, or do nothing (status quo).

5. Identified Need

5.1 Network Overview

The area of UE's distribution network that is the subject of this Regulatory Investment Test for Distribution (RIT-D), is the East Malvern Zone Substation (EM) supply area, that includes parts of the suburbs of Chadstone, Alamein, Carnegie and East Malvern, in Melbourne's south-eastern suburbs.

EM is owned and operated by UE, providing power to approximately 14,234 customers, with the majority of the load at EM comprising of residential and commercial customers.

EM is a 66/11 kV zone substation, with two 20/33 MVA transformers, servicing its supply area with 10 x 11 kV distribution feeders.

EM is bounded mainly in the west and south by adjacent 11 kV zone substations CFD (Caulfield), OR (Ormond) and K (Gardiner) providing transfer capacity to be able to reduce load on the zone substation in the event of an emergency (such as a major asset failure, for example). The load transfer capability away from EM is 6.8 MVA.

The rating of EM with all transformers in service is 62.4 MVA, and with one transformer out of service the rating reduces to 31.2 MVA. This compares to a forecast 10% PoE maximum demand of 38.2 MVA for summer 2024/25, rising to 39.2 MVA by 2027/28.

The electrical single line diagram for EM, showing the 66 kV assets, 66/11 kV transformers, and 11 kV assets (including distribution feeder exits) is illustrated in Figure 1.

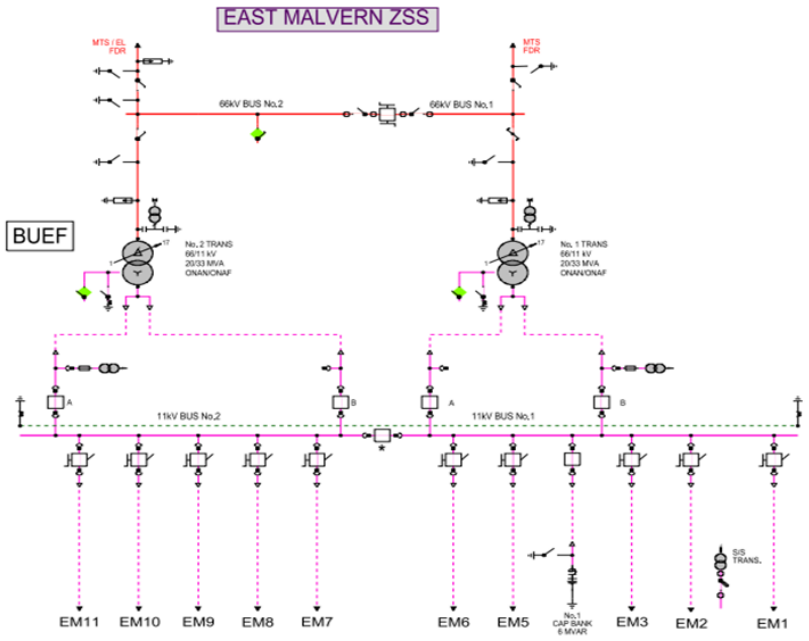

Figure 1: EM Electrical Single Line Diagram

The power supply coverage of EM is illustrated in Figure 2.

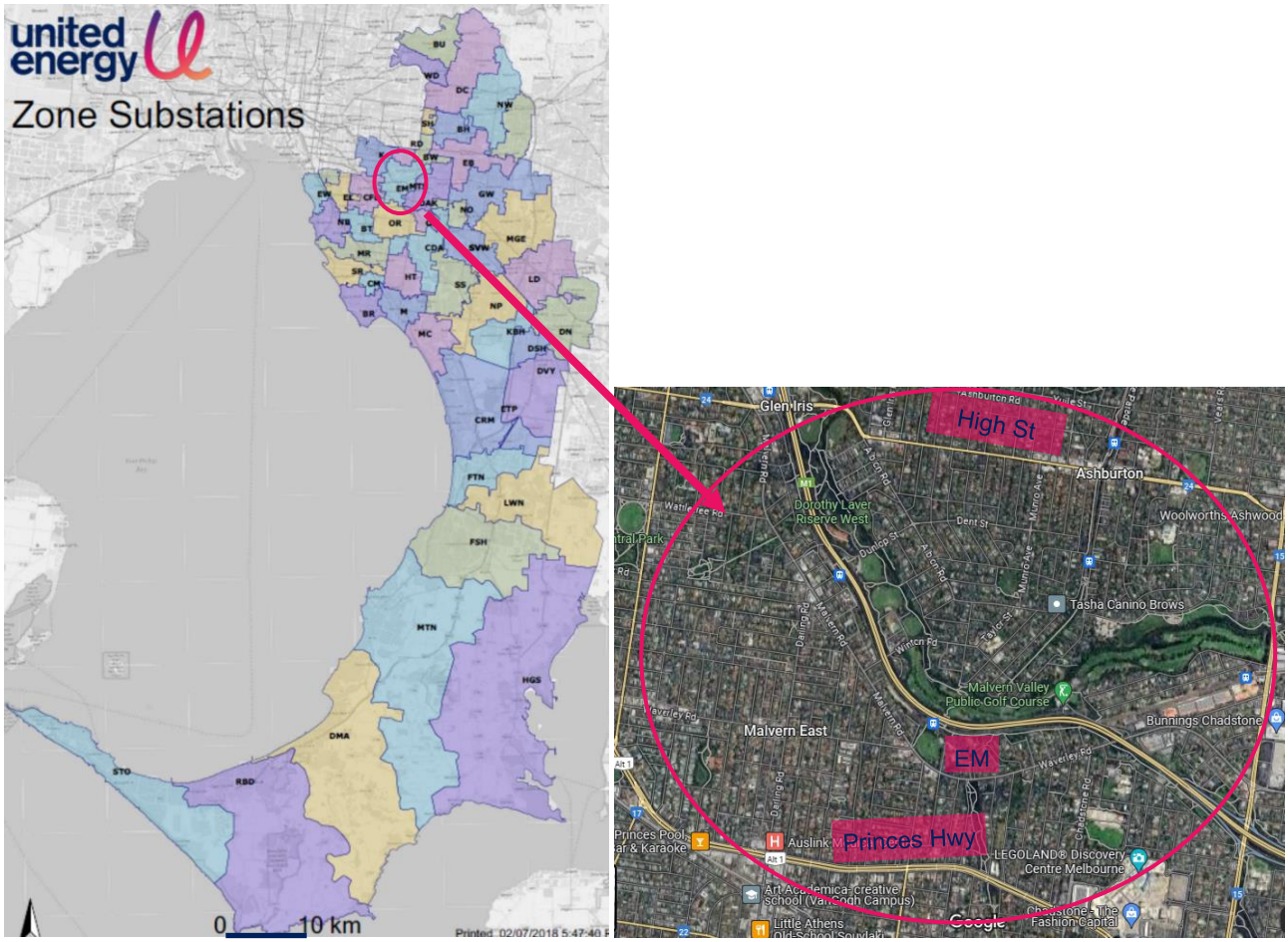

Figure 2: EM Supply Area

5.2 Description of the Identified Need

UE has prepared this report to assess whether the reliability and safety needs at EM could be realised either fully, or in part through non-network or SAPS options. To assess whether a non-network or SAPS option could be beneficial, it is important firstly to define the identified need for this location.

The identified need at EM is to;

i) protect power sector workers and members of the public from harm caused by equipment failure (Safety); and

ii) continue to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (Reliability).

The condition of the 11 kV switchboard, protection and control relays, and other secondary assets at EM is deteriorating. Most of these assets are now technically obsolete, being unsupported by equipment suppliers, with limited to no spares.

UE has assessed there is now an unacceptable risk of asset failure, with significant consequences for safety, and for the reliability of electricity supply to UE's customers within the EM supply area. The switchboard and secondary assets are no longer considered fit for purpose and need to be safely removed from service. While there is a need to remove these assets from service, there also remains a need to continue to supply electricity to customers within the EM supply area serviced by these assets. The reliability and safety risk cost for the EM supply area is considered to be significant.

The assets whose condition is of key concern are identified below and in Appendix A:.

5.2.1 Switchboard Condition

EM has an aged 11 kV Reyrolle LMT oil-insulated non-arc-fault-contained switchboard for both of its 11 kV buses, installed in 1961. This switchboard is 63 years old and its condition poses a safety and reliability risk. As the switchboard predates current standards, any internal arc fault will not be contained and would be expelled into the switch-room, which poses a safety risk to assets and personnel if they are present. This switchboard has already undergone life extension, with retrofitted feeder vacuum-type circuit breakers installed, however this retrofit was undertaken more than 20 years ago.

All other switchboards of this make have already undergone replacement following multiple failures over the past 10 years. This is the last of the Reyrolle switchboards in-service on UE's network. Availability of spare parts remains a risk if it is retained.

5.2.2 Protection and Control Equipment Condition

Protection and control systems are critical to the safe and reliable operation of the network. These systems are designed to detect the presence of power system faults and/or other abnormal operating conditions, and to automatically isolate the faulted network by the opening of appropriate high-voltage circuit breakers.

Failure to isolate power system faults will invariably result in severe damage to network assets, presenting a serious health and safety hazard to the public, and greatly increases the risk of fire starts.

Many of the protection and control relays at EM are now technically obsolete, being no longer supported by vendor, and limited spares. These factors increase the likelihood of a power system fault not being detected, or a maloperation. The obsolete Siemens Siprotec-4 relays at EM have experienced several failures, including four failures since 2019.

The 11 kV switchboard structural leakage protection has also mal-operated resulting in spurious trips, including one in 2023. There is a risk it may occur again.

5.3 Quantification of the Identified Need

Table 3 summarises the forecast impact of the identified network need discussed in Section 5.2 on customers. The table shows over the forecasting period, the risk costs and hence the potential market benefits considered, including:

- Expected unserved energy (EUE) cost, which is the value of the energy at risk after taking into account the probability of asset failures or malfunctions at EM, representing the deterioration in supply reliability within the EM supply area.
- Safety risk cost, which is the cost of harm to UE's staff and the general public located within the EM supply area, as a result of safety incidents caused by asset failures or malfunctions at EM.
- Total risk cost, which is the sum of the expected unserved energy cost and the safety risk cost.

Table 3: EM Reliability and Safety Risk Quantification ($'000, Real 2024)

Financial Year	Expected Unserved Energy Cost	Safety Risk Cost[3]	Total Risk Cost
2024	482	60	542
2025	491	65	556
2026	760	71	831
2027	870	77	947
2028	883	84	967
2029	901	90	991
2030	924	97	1021
2031	953	104	1057
2032	984	111	1096
2033	1006	119	1125

[3] For simplicity, no AFAP disproportionate factors have been applied to the Safety Risk Cost.

Financial Year	Expected Unserved Energy Cost	Safety Risk Cost[3]	Total Risk Cost
2034	1016	126	1142
2035	1026	134	1160
2036	1036	142	1179
2037	1047	150	1198
2038	1059	159	1218
2039	1071	167	1238
2040	1083	176	1258

For the purposes of this RIT-D which involve both high-voltage switchboards and secondary systems, economic evaluations are undertaken over a 25-year period.

6. Key Assumptions in Relation to the Identified Need

6.1 Method for Quantifying the Identified Need

UE adopts its Asset Risk Quantification Guide (UE-GU-2011) in quantifying safety and reliability risks associated with asset condition failures and their consequences. This modelling is based on Weibull distribution parameters for each asset class.

6.1.1 Safety

The safety risk to UE employees and the general public, arising from potential failure or malfunction of network assets is quantified by UE using a safety risk cost, based on the asset conditions. The ability to maintain a safe network for the EM supply area is increasingly difficult due to the poor and deteriorating condition of the EM switchboard and its secondary system assets.

UE's approach to safety risk is based on the As Far As Practicable (AFAP) principle. The AFAP principle recommends safety risk reduction measures be implemented unless the cost, time or form of the risk reduction measure is grossly disproportionate to the benefit gained from the reduced risk. A "Do Nothing" (or run to failure) approach would result in the poor condition assets remaining in service, deteriorating further, and completely failing to address any safety concerns.

6.1.2 Reliability

UE's reliability planning standard for its zone substation assets is based on a probabilistic planning approach which quantifies Expected Unserved Energy (EUE) which is defined in terms of megawatt hours (MWh) per annum of energy not supplied, taking into account the probability of an asset failure or malfunction, and expresses this financially by applying a Value of Customer Reliability (VCR) ($/MWh).

6.2 Forecast Maximum Demand

EM provides power to approximately 14,234 customers to parts of the suburbs of Chadstone, Alamein, Carnegie and East Malvern, with the majority of the load at EM comprising of 91% residential and 9% commercial customers.

A credible network, non-network or SAPS solution should consider the forecast maximum demand for the EM supply area shown in Table 4. Forecasts of the 10% PoE and 50% PoE summer maximum demand and power factor at EM are presented. These forecasts are based on an expected economic growth scenario.

Table 4: EM Maximum Demand Forecast

Time Period	Power Factor	10% PoE (MVA)	50% PoE (MVA)
2024-25	1.00	38.2	35.0
2025-26	1.00	38.6	35.3
2026-27	1.00	38.9	35.6
2027-28	1.00	39.2	35.9
2028-29	1.00	39.5	36.3

6.3 Forecast Annual Energy

A credible network, non-network or SAPS solution should consider the annual energy requirements of customers within the EM supply area as shown in Table 5.

Table 5: EM Annual Energy Forecast

Time Period	Energy (GWh pa)
2024-25	128
2025-26	129
2026-27	130
2027-28	131
2028-29	133

6.4 Characteristic of Load Profile

A credible network, non-network or SAPS solution should be able to support the load profiles below.

UE has prepared load profiles that are characterised by the use of profiles from the most recent 50% PoE year. Based on this approach, the 2022/23 historical demand profiles have been prepared and presented herein.

The coincident maximum demand of the customers within the EM supply area occurs on days of extreme ambient temperature during summer. The annual demand profile at EM expressed as a percentage of the 50% PoE maximum demand listed in Table 4, is illustrated in Figure 3.

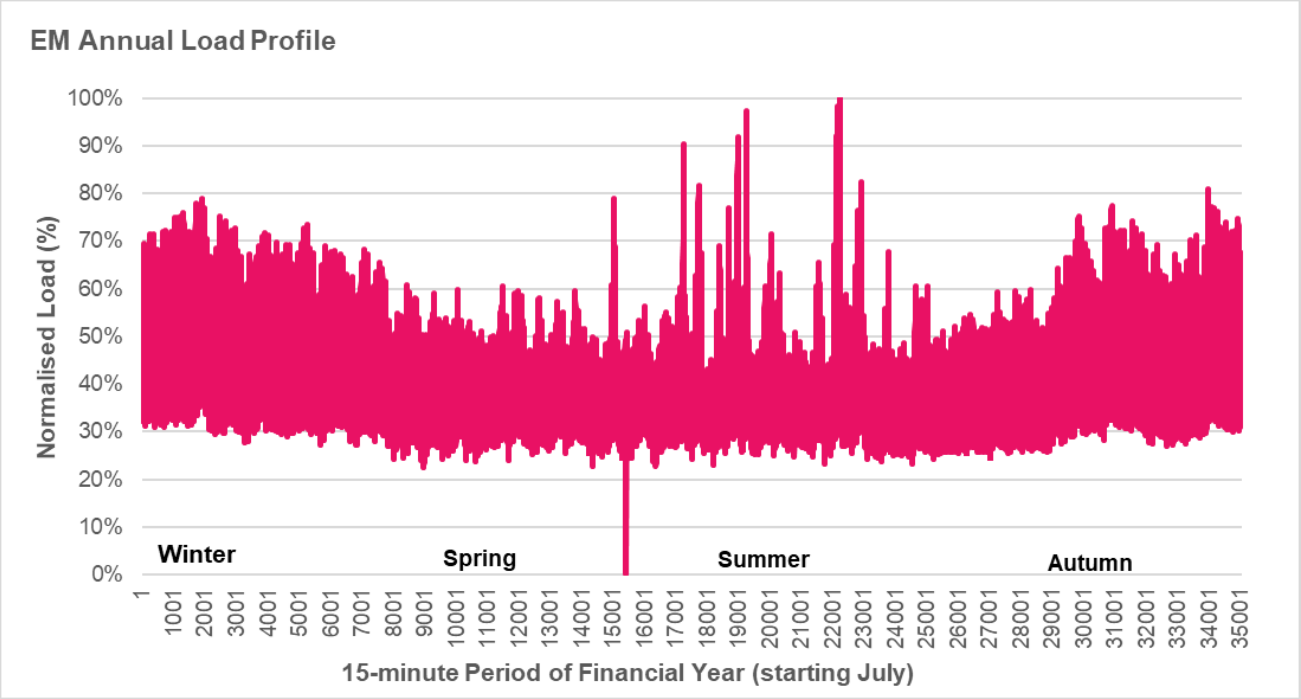

Figure 3: Annual Load Profile at EM

The load profile on the day of a 50% PoE summer maximum demand is illustrated in Figure 4. The prominence of air-conditioning load within the EM supply area, results in a maximum demand occurring during the late afternoon.

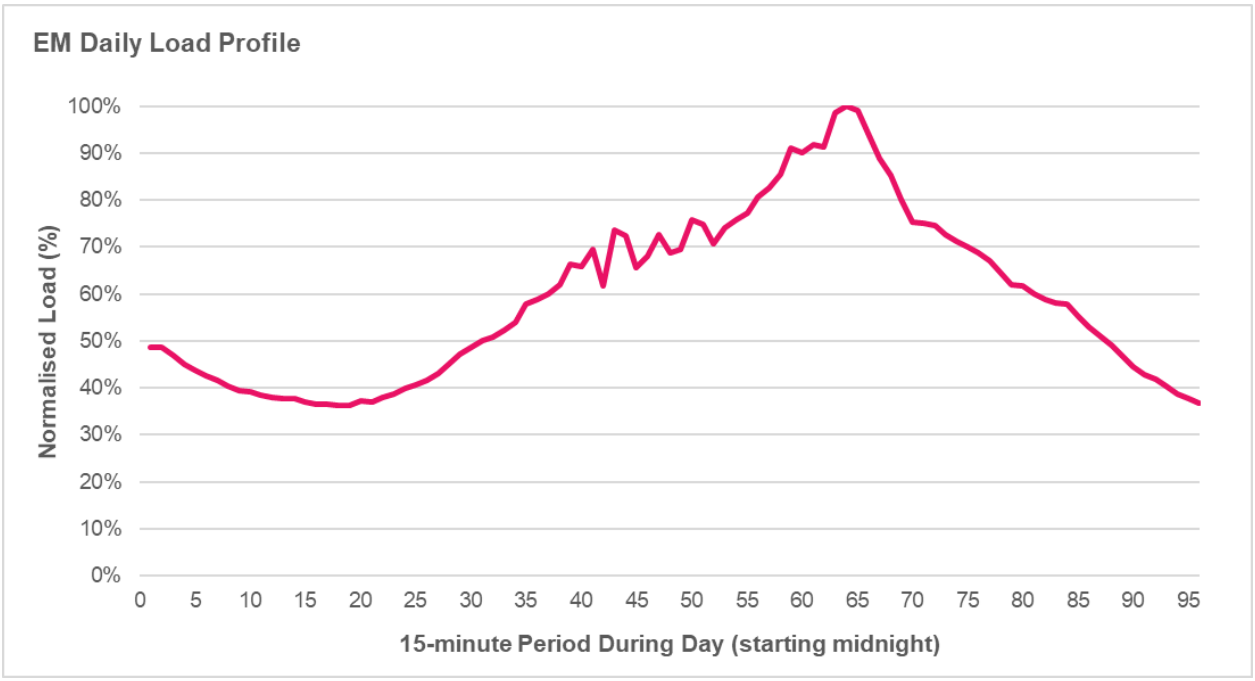

Figure 4: Load Profile on Day of Summer Maximum Demand at EM

Figure 5 shows the normalised annual load-duration curve at EM for a 50% PoE summer maximum demand year.

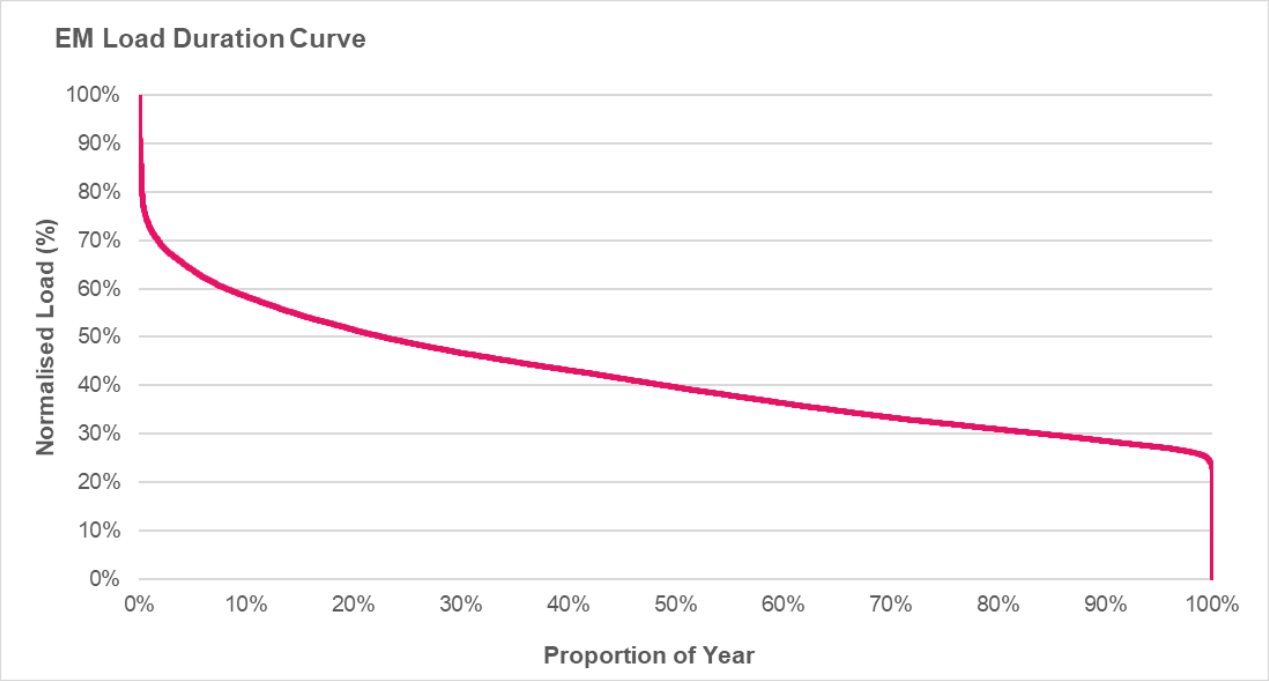

Figure 5: Annual Load-Duration Curve at EM

The load characteristics can vary marginally from year to year due to changes in weather, solar generation systems growth, and underlying changes in the customers' load usage. Figure 5 shows that load in excess of 80% of the maximum demand lasts for less than 1% of the year. It also shows that EM normally never operates below 25% of its maximum demand.

6.5 Load Transfer Capacity and Supply Restoration Times

A credible network, non-network or SAPS solution can assume the minimum load transfer capability between EM and the neighbouring networks of CFD, OR and K (among others) to be 6.8 MVA for summer 2024/25, noting that most of the load transfer capability is only available from the western and southern side of the EM supply area.

Future load transfer capability levels between EM and the neighbouring network can be assumed to remain relatively constant.

A credible network, non-network or SAPS solution should provide for supply to be restored within 60 minutes (on average) following the loss of a plant item causing an outage.

6.6 Discount Rates

To compare cash flows of options with different time profiles, it is necessary to use a discount rate to express future costs and benefits in present value terms. The choice of discount rate will impact on the estimated present value of net market benefits, and may affect the ranking of alternative options. A discount rate of 7.0 per cent is used[4].

6.7 Asset Ratings

The existing capabilities of EM zone substation for summer and winter are presented in Table 6 for all plant in service (N), and for one transformer out of service (N-1).

[4] Based on AEMO's 2023 IASR, Table 31.

Table 6: Summary of EM Ratings (MVA)

Zone Substation	Summer Cyclic Rating at 40°C		Winter Cyclic Rating at 10°C	
	N	N-1	N	N-1
EM Import[5]	62.4	31.2	70.0	35.0
EM Export[6]	-54.0	-27.0	-54.0	-27.0

6.8 Value of Customer Reliability

Location-specific Value of Customer Reliability (VCR) is used to value reliability of supply. The locational VCR for the EM supply area was derived from the sector VCR estimates provided by the AER, weighted in accordance with the composition of the load, by sector, and escalated by CPI. This is summarised in Table 7.

Table 7: Summary of Location Specific VCR

Zone Substation	VCR ($ per MWh, Real 2024)
EM	34,050

6.9 Potential Credible Options to Address the Identified Need

UE has developed a set of potential credible options to address the identified need relating to the East Malvern Zone Substation Switchboard and Secondary Systems Assets Condition.

To address the safety need, credible network, non-network or SAPS options would be required to have characteristics that would allow the safe decommissioning or rectification of the EM switchboard and secondary systems. Furthermore, to address the reliability need in anticipation of the safe decommissioning of the EM switchboard and secondary systems, credible options would need to be capable of supplying the annual energy requirements of customers supplied by EM, and the forecast maximum demand at EM over the planning horizon.

Table 8 provides a summary of the base case option, using the risk costs presented earlier in Table 3.

Table 8: Base Case

Option	Description
Do Nothing (status quo)	This base case option involves running the EM switchboard and secondary systems to failure. That is, continue with existing maintenance of the switchboard and secondary systems, coupled with replacement upon failure. Given this option does not address the identified need at all, the cost of unplanned asset failures is represented by the full value of both the EUE and the safety risk costs. The present value of all costs (EUE and safety risk) is $13.09 million (Real, 2024).

Table 9 provides a summary of credible options that could address the identified need.

[5] Power flow towards customer load.
[6] Power flow towards the transmission network.

Table 9: Credible Options Under Consideration

Option	Description
1- Replace the EM switchboard and secondary systems in an extended existing building (by November 2025)	This option involves replacing the two-bus switchboard and the secondary systems in an extension of the existing building, built to UE's latest design standards. This option addresses both the safety need and reliability need. The total capital cost of this option is $10.08 million (Real, 2024). The present value of all costs (capital, O&M, EUE and safety risk) is $10.87 million (Real, 2024).
2 - Replace the EM switchboard and secondary systems in a new building (by November 2026)	This option involves replacing the two-bus switchboard and the secondary systems in a new pre-fabricated building, built to UE's latest design standards. This option addresses both the safety need and reliability need. The total capital cost of this option Is $11.95 million (Real, 2024). The present value of all costs (capital, O&M, EUE and safety risk) is $12.65 million (Real, 2024).

A credible option needs to be technically and economically feasible, and able to be implemented within a reasonable timeframe to address the identified need. Table 10 describes the options that have been considered by UE and are regarded as not being credible for the reasons set out below. These include all remaining network, non-network and SAPS options.

Table 10: Options Regarded as Being Not Credible

Option	Description
Decommission EM in its entirety and transfer all EM load to CFD, OR and K	This option allows for the decommissioning of EM in its entirety by transferring all of its load to the adjacent zone substations CFD, OR and K. 31 MW of new feeder capacity (approximately 5 new 11 kV feeders) would need to be established to transfer EM's entire load base to these zone substations. Both OR and K would each need to be augmented with an additional 20/33 MVA transformer and 11 kV switchboard. Given the scale of the works required to achieve this outcome would be in excess of $30 million, this option is not regarded as credible.
Install 3rd bus and decommission poor condition assets at EM, transferring half of EM load to CFD and K	This option allows for the decommissioning of the poor condition equipment at EM by transferring half of its load to the adjacent zone substations CFD and K. 16 MW of new feeder capacity (approximately 3 new 11 kV feeders) would need to be established to transfer half of EM's load base to these zone substations. K would each need to be augmented with an additional 20/33 MVA transformer and 11 kV switchboard. Given the scale of the works required to achieve this outcome would be in excess of $18 million, this option is not regarded as credible.
Power factor correction	The power factor at EM is unity at times of maximum demand, and there is no further opportunity to reduce demand at the network or customer level as seen by EM. Therefore this option is not credible, because it cannot technically address the identified need in relation to reliability or safety risks associated with deteriorating asset condition.
Demand response programmes	Demand response programs are generally designed for peak demand management. The ability of all customers to be self-sufficient in their electricity demand at all times and for all year round to meet the identified need, is considered to be unfeasible, as it effectively requires all customers within the EM supply area to disconnect from the network. Hence this option is not credible.

Option	Description
Customer and/or community intermittent renewable generation and energy storage	Distributed generation of up to 31 MW using solar PV is likely to require more than 31 hectares of land[7]. Devoting this amount of land to energy production in a dense, urban environment is unlikely to be feasible. Nevertheless, coupling this with customer solar PV installations in the EM supply area, particularly with the availability of commercial and residential roof-space, could reduce the amount of additional generation required, at a competitive cost. The challenge however lies in the provision of storage to back-up the solar PV panels when they are not generating (including during the evenings). A viable storage option that meets the maximum demand at EM and reliably meets customer requirements requires 'N' batteries (where 'N' ≥ 2) each able to supply (31 ÷ N) MWp, each with an energy to power ratio of around 10[8]. This would enable the system to meet maximum demand and coupled with solar PV, supply the annual energy needs. The costs of the storage alone are likely to exceed those of the preferred network option. For example, the fully installed capex cost of storage is approximately $0.9 million per MWh[9], totalling $279M (excluding land). Adding generation, demand management or efficiency measures to this option would reduce the battery requirements stated above. This option would lead to a much higher marginal cost to the customer compared to a network solution cost, and the gap is unlikely to be covered from other market-based revenues. The planning process required for this type of investment, also means this is unlikely to be completed in time to meet the identified need. The storage resources currently owned by individual customers indicates that no potential existing customer-owned storage would be large enough to meet the identified need. Therefore this option is not considered to be credible.
Dispatchable generation and/or Customer standby generation	A viable generation option that meets the maximum demand at EM and reliably meets customer requirements requires at least two generators to allow maintenance on one generator during off-peak times, each able to supply up to (31 ÷ N) MWp, where 'N' is the number of generators. This would enable the system to meet maximum demand and supply the annual energy needs. The costs of this are likely to exceed those of the preferred network option. For example, the capex cost of a small gas-fired generator is approximately $1.25 million per MW[10]. For 31 MW of generation, the cost will be over $38M, excluding land, connection and operating costs. Adding storage, demand management or efficiency measures to this option would reduce the generation requirements stated above, and potentially the costs. This option would lead to a much higher marginal cost to the customer compared to a network solution cost, and the gap is unlikely to be covered from other market-based revenues. The planning process required for this type of investment, also means this is unlikely to be completed in time to meet the identified need. The maximum demands of individual customers indicate that no potential existing customer-owned generation (standby or otherwise) would be large enough to meet the identified need. Therefore this option is not considered to be credible.

[7] https://www.quora.com/How-much-land-is-required-to-setup-a-1MW-solar-power-generation-Unit-1
[8] 115,000 MWh pa / 366 days pa / 31 MW = 10.
[9] https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aurecon-2022-cost-and-technical-parameter-review.pdf

[10] https://aemo.com.au/-/media/files/electricity/%E2%80%8Cnem/%E2%80%8Cplanning_and_%E2%80%8Cforecasting/%E2%80%8Cinputs-assumptions-methodologies/%E2%80%8C2021/Aurecon-Cost-and-Technical-Parameters-Review-2020.pdf

7. Technical Characteristics of Non-Network Options

This section describes the minimum technical characteristics that a non-network or SAPS option would be required to deliver to address the identified need.

Like the network options, credible non-network and SAPs options would be required to have characteristics that would allow the safe decommissioning of EM, and would need to be capable of supplying the annual energy requirements of all customers supplied by EM, and the maximum demand at EM over the planning horizon.

A credible non-network or SAPS option, or any combination of those (including with a network option) must satisfy timing, operational and the minimum technical requirements stipulated below.

7.1 Size of Support

Table 11 outlines the estimated amount of load reduction, or additional generation needed to be supplied by a credible non-network or SAPS solution within the EM supply area to address the identified need. These are the minimum requirements, because the values reflect the reduced requirement needed due to the availability of load transfer capability away from EM to its surrounding zone substations.

Table 11: Minimum Peak Demand and Annual Energy Offsets Required from Non-Network or SAPS Solutions

Year	Load at Risk (MVA)	Hours at Risk (Hours)	Minimum Non-Network or SAPS Support Required	
			Expected GWh pa	Expected MWp
2024-25	31.4	8760	115	31.4
2025-26[11]	31.8	8760	116	31.8
2026-27	32.1	8760	117	32.1
2027-28	32.4	8760	118	32.4
2028-29	32.7	8760	119	32.7

7.2 Time of Year, Duration and Location of Support

Proposed non-network or SAPS options, at a minimum, must be capable of supplying the entirety of the EM supply area maximum demand and annual energy, excluding those areas on the west and south of EM that border with CFD, OR and K, that are able to be transferred away to those neighbouring zone substations, utilising the available transfer capability.

This service is required no later than by the end of 2025.

7.3 Reliability of Support

Proposed non-network and SAPS options must be capable of reliably meeting electricity demand under a range of conditions, and be able to maintain reliability and quality of supply for customers supplied within the EM supply area.

As such, redundancy may need to be built into a non-network or SAPS solution in order to maintain reliability of supply.

If the non-network option is a generator operating in parallel with UE's network, the generator must comply with the requirements set out in UE's Embedded Generation Network Access Standards (Document No. UE ST 2008.X).

[11] Year of preferred network option.

8. Conclusion and Next Steps

8.1 Conclusion

Given the size of the support needed from a non-network or SAPS solution, and it being required at all times of the year to maintain supply reliability within the EM supply area (following the safe decommissioning of EM), it is unlikely that a non-network or SAPS option could be technically and economically viable to address the identified need.

In conclusion, this Notice of Determination report demonstrates that none of the non-network or SAPS options are potentially feasible in this instance. The analysis demonstrates that there are no combinations of non-network or SAPS options, or in combination with network options, that are likely to adequately meet the criteria that would require the publishing of, and consultation on a RIT-D options screening report.

8.2 Next Steps

The total cost of the most expensive credible network option to address the *East Malvern Zone Substation Switchboard and Secondary Assets Condition* identified need, is less than the trigger threshold of $12 million[12] for the publication of and consultation on a Draft Project Assessment Report (DPAR).

Therefore, UE shall now prepare and publish a Final Project Assessment Report (FPAR), as required under NER clause 5.17.4, paragraphs (o) to (s), which will present a detailed economic assessment of all credible network options that address the identified need, and will identify the preferred option and its timing.

The FPAR shall provide information required under NER clause 5.17.4, paragraph (j), and will apply the latest available information on reliability and safety risk costs associated with the identified need, and the project cost estimates, in evaluating the economic viability of the preferred option against the alternative options considered.

UE intends to publish the FPAR by 31st May 2024.

[12] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021

Appendix A: Switchboard and Secondary Assets Photos

EM has an aged 11 kV Reyrolle LMT oil-insulated non-arc-fault-contained switchboard as shown below, installed in 1961. There are obsolete Siemens Siprotec-4 relays which have experienced several failures, including four failures since 2019.



Figure 6: In-Service Obsolete Switchboard, Relays and Associated Equipment at EM