Notice of Determination of No Non-Network Options

# Connection of large customers in the Mt Cottrell area

**October 2024**

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# 1 Introduction

Two large commercial customers who are in close physical proximity in the Mount Cottrell area have approached us via separate connection enquiries under chapter 5 of the National Electricity Rules (NER). The loads are significant enough that we initiated a Regulatory Investment Test for Distribution (RIT-D) to investigate the provision of supply to these new customer connections.

In carrying out the non-network options screening stage of the RIT-D process, we have in accordance with NER clause 5.17.4(c), made a determination that there are no credible Non-Network Options that provide an efficient solution for connection.

The publishing of this document provides the formal requirements of clause 5.17.4(d), containing the reasons why we consider there are no non-network or Stand Alone Power System (SAPS) options that could form a credible efficient option.

# 2 Overview

## 2.1 Background

There are two new large-load commercial connection applications located close together in the Mount Cottrell area in Melbourne's western development zone, approximately indicated by the dotted yellow ring in Figure 1.


Figure 1 Site of new connections near Mt Cottrell, west of Melbourne

The Mount Cottrell area would require significant infrastructure to service these large load connections (12MVA and 6 MVA discrete loads) as they are located between existing substations at Werribee (WBE), Laverton (LV), Truganina (TNA) and Melton (MLN). The distribution network lines from these substations to the site of the new connections cannot run the requested loads.

## 2.2 Application of the Regulatory Investment Test – Distribution (RIT-D)

Having a project value for a network solution likely to be in excess of $6m[1], this project meets the criteria of clause 5.17.3 of the NER and as such is subject to a RIT-D. This process requires us to screen for non–network options.

This document represents the first formal stage of the RIT-D process for this project in screening for non–network options, and forming a determination if warranted, to support assessment of how to provide supply most efficiently to the new customer connections.

[1] https://www.aer.gov.au/industry/registers/resources/reviews/cost-thresholds-review-regulatory-investment-tests-2021

# 3 Identified need

## 3.1 Identified need

Under Chapter 5 of the National Electricity Rules (NER), we are required to connect customers and in doing so, we must achieve the specified performance standards. Customers must be connected such that it will not adversely affect other registered participants.

We therefore consider the identified need for this investment to be 'providing adequate customer supply' under the RIT-D, as the investment is required to comply with the above NER obligations.

The connecting customers will be required to contribute to the cost of the preferred connection solution.

## 3.2 Quantification of identified need

The Mount Cottrell loads targeted to be commissioned by Quarter 2 2025.

The forecast for the two loads at Mount Cottrell is flat over the next 10 years with an anticipated diversified demand of 18 MVA. This is a result of the dedicated function to supply to two large customers.

The energy consumption at a minimum power factor of 0.9 lagging is assessed at a maximum of 16.2 MWh per hour during business operations with an overall 60% load factor across 24/7 operations (233 MWh / day). Applying a simplistic approach of load profile over the capacity of existing assets gives results shown in Table 1.

Table 1 Forecast duration of load at risk for new connection large loads

| Forecast (MVA) | Load at Risk (MVA) | Hours above limit pa | MWh above limit pa |
|---|---|---|---|
| 18 | **18** | **8,760** | **85,147** |

## 3.3 Possible solutions

Connection to the existing distribution network is possible however this has limited capacity and is not capable of supplying the total load of both connections. Therefore, some form of augmentation and or non-network solution will be required to enable the connection of the loads.

Solutions can be grouped into 3 generalised categories; Internal customer strategies, localised solutions (at or close to load site), and, remote solutions. Options for these possible solutions will be discussed in following sections separately for credible network solutions (Section 4) and non-network options (Section 6).

## 3.4 Special consideration for solutions that are remote from site

### a) Distribution lines

Any solutions that fall into the remote solutions that will interface with the distribution poles and wires network may need to take into account the physical aspects of the lines in the area.

The distances from each of the surrounding substations are shown in Table 2. Note that the distances are a direct measure and that the distribution lines are significantly longer as they utilise roads and properties to traverse the terrain.

Table 2 Direct distances from adjoining substation to site of new loads

| Substation | km |
|---|---|
| **Melton (MLN)** | 12 |
| **Truganina (TNA)** | 9 |
| **Laverton (LV)** | 10 |
| **Werribee (WBE)** | 13 |

Upgraded infrastructure and or new circuits will be required to transport the required loads while keeping supply quality within limits to the site. If an option was used to connect the new loads to the upgraded existing distribution network (irrespective of the energy source) upstream of the surrounding substation(s), augmentation of one or more substations will be required.

### b) Zone substations – load characteristics and Demand Forecasts

Each substation site has:

- a Nameplate and cyclic rating for when all components are in service in a normal operating configuration (N).
- a Nameplate and cyclic rating for when the operating configuration of a substation is such that if no more primary equipment can be taken out of service, intentionally or otherwise, without causing an interruption of supply to connected customers (N-1).

The allowed demand cyclic ratings are higher than nameplate ratings by implementing managed periods of overloading (cycling), allowing more energy to be delivered at a rate higher than full time loading limitations. This situation cannot be implemented permanently without damaging the equipment.

The forecast charts will show two probabilities of load growth (Probability of Exceedance or POE):

- 10% POE is the highest forecast result with a probability of 10% of this scenario being exceeded (less likely but possible), and,
- 50% POE, a more likely outcome of load forecasting which forms the basis of assessment in this report.

Table 3 provides a summary of exceedances of the N and N-1 ratings for each substation in this western growth area.

Table 3 Summary of rating exceedance timing without new loads connected

| Substation | Exceed N-1 rating | Exceed N rating |
|---|---|---|
| **MLN** | now | 2031 |
| **LV** | now | 2031 |
| **TNA** | now | 2033 |
| **WBE** | now | 2026 |

Load forecasts and typical consumption profiles are shown in the next sections, with data sourced from our 2023 Distribution Annual Planning Report (DAPR) combined with the addition of high confidence non-committed loads.

i. Melton Substation (MLN)

MLN services domestic and commercial loads and is situated to the north of Mount Cottrell area. As shown in Figure 2, the N-1 cyclic rating is currently exceeded, and the load forecast is that it will reach its station 50% POE “N” cyclic rating after 2031.

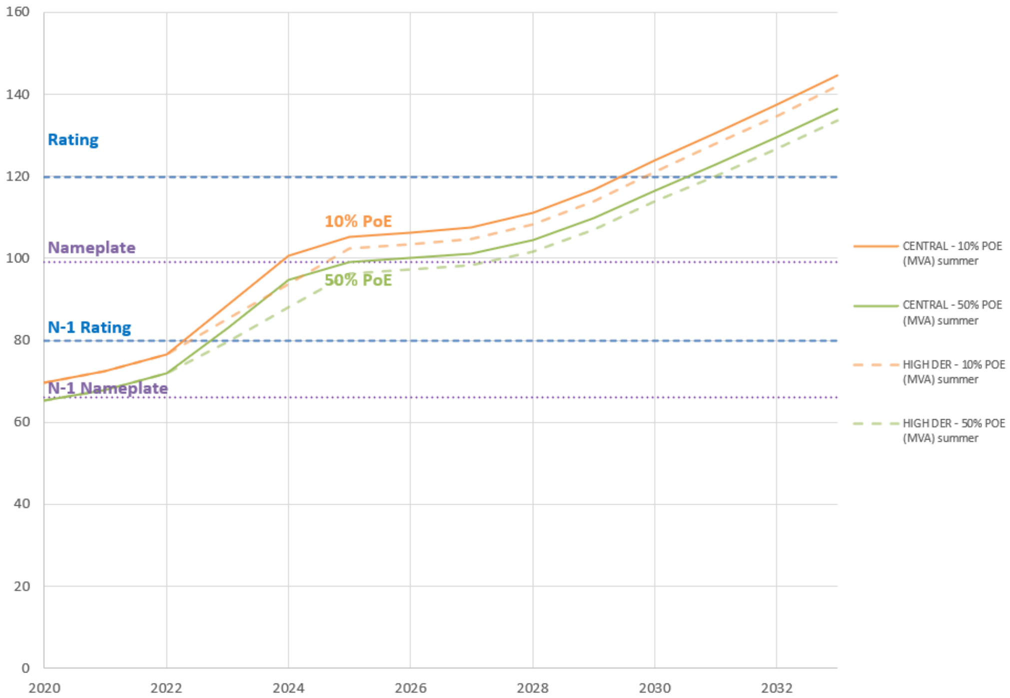


Figure 2 Melton Substation (MLN) Summer loading Forecast (MVA)

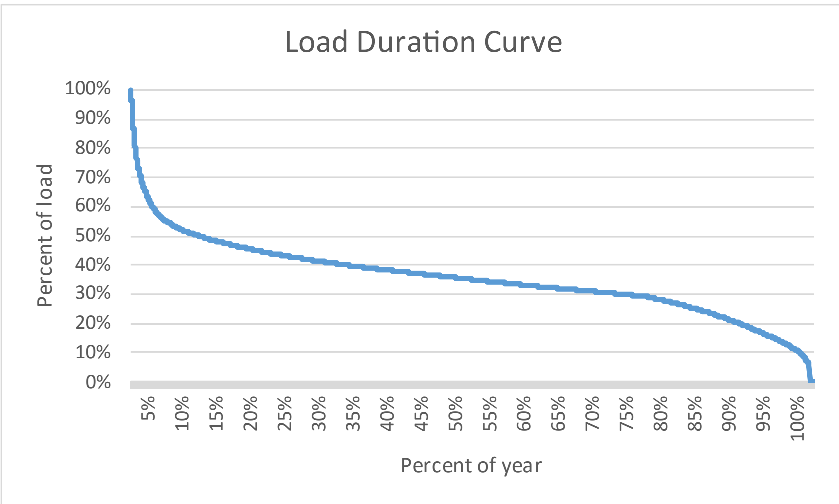


Figure 3 MVA Load Duration Curve for Melton Substation (MLN)

ii. Laverton Substation (LV)

LV supports a growing number of commercial and residential loads in the Tarneit region situated southeast of Mount Cottrell. As shown in Figure 4, this substation currently exceeds its N-1 rating and the load forecast is that it will reach its station 50% POE “N” cyclic rating prior to 2031.

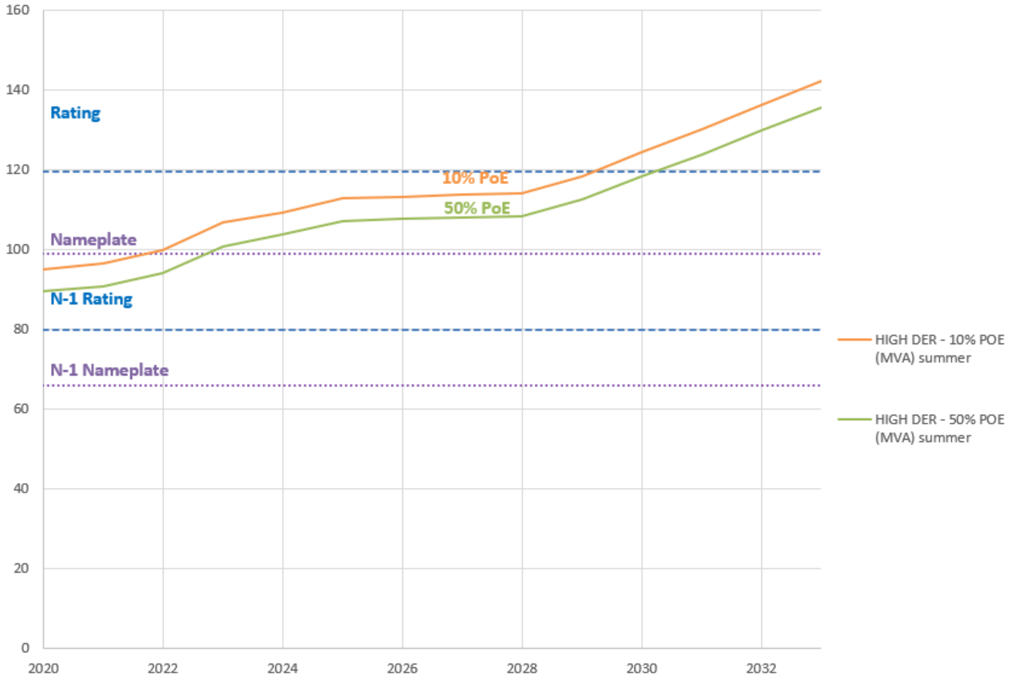


Figure 4 Laverton Substation (LV) Summer Loading Forecast (MVA)

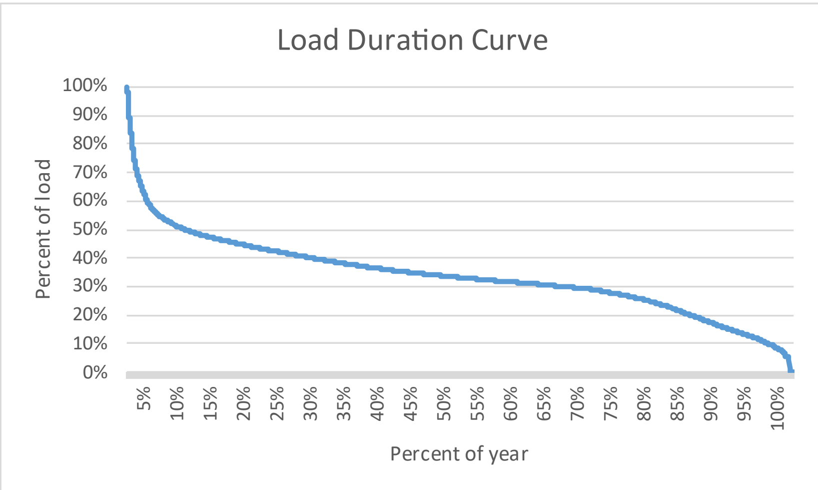


Figure 5 MVA Load Duration Curve for Laverton Substation (LV)

iii. Truganina Substation (TNA)

TNA supplies domestic and commercial loads and is situated southeast of the Mount Cottrell area. As shown in Figure 6, this substation currently exceeds its N-1 rating and the load forecast is that it will reach its station 50% POE "N" cyclic rating beyond 2033.

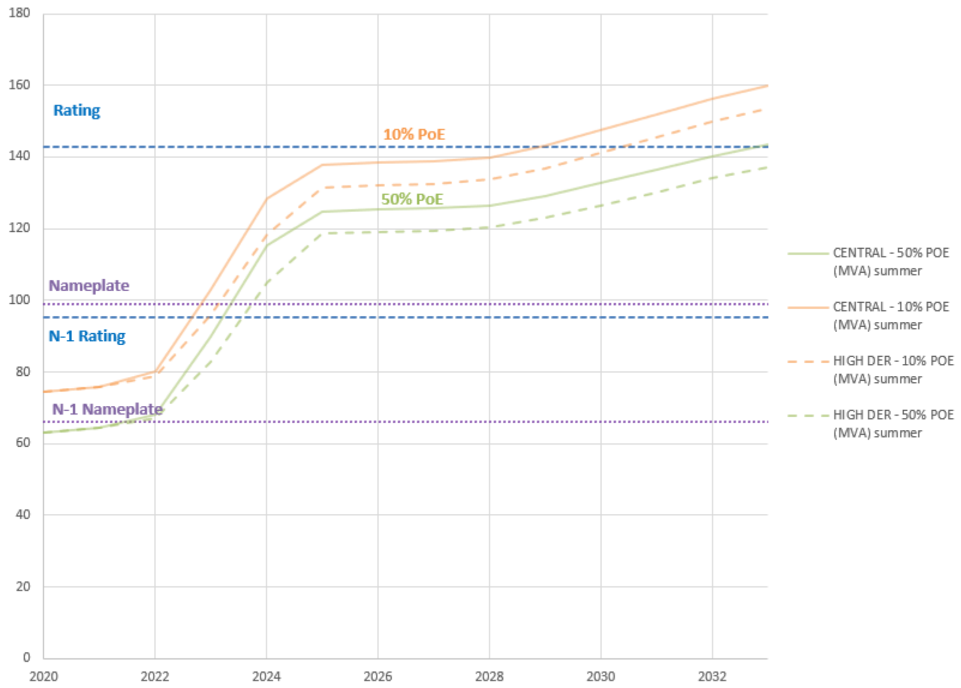


Figure 6 Truganina Substation (TNA) Summer Load Forecasting (MVA)

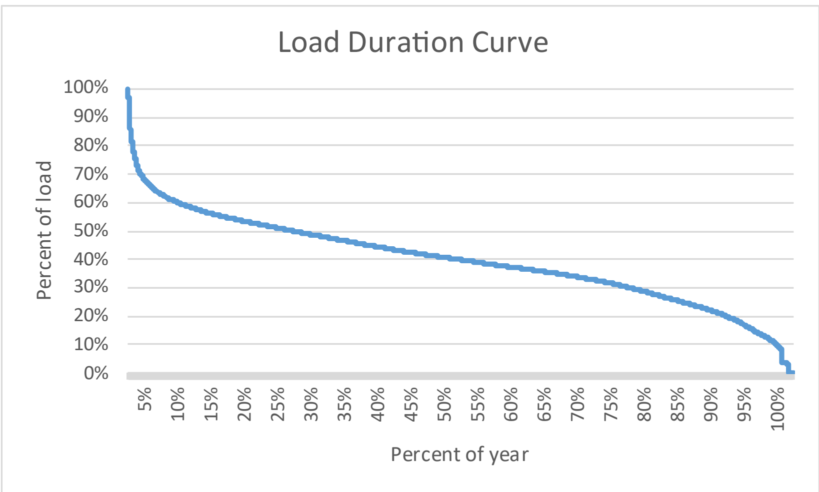


Figure 7 MVA Load Duration Curve for Truganina Substation (TNA)

iv. Werribee Substation (WBE)

WBE supports a rapidly growing number of commercial and residential loads and is situated in the region south of Mount Cottrell. As shown in Figure 8, this substation currently exceeds its 50% POE N-1 cyclic rating and the load forecast shows that it will likely reach its station 50% POE "N" cyclic rating somewhere around 2026.

WBE has little to no peak transfer capacity available beyond 2023 to support other substations in this western growth corridor.

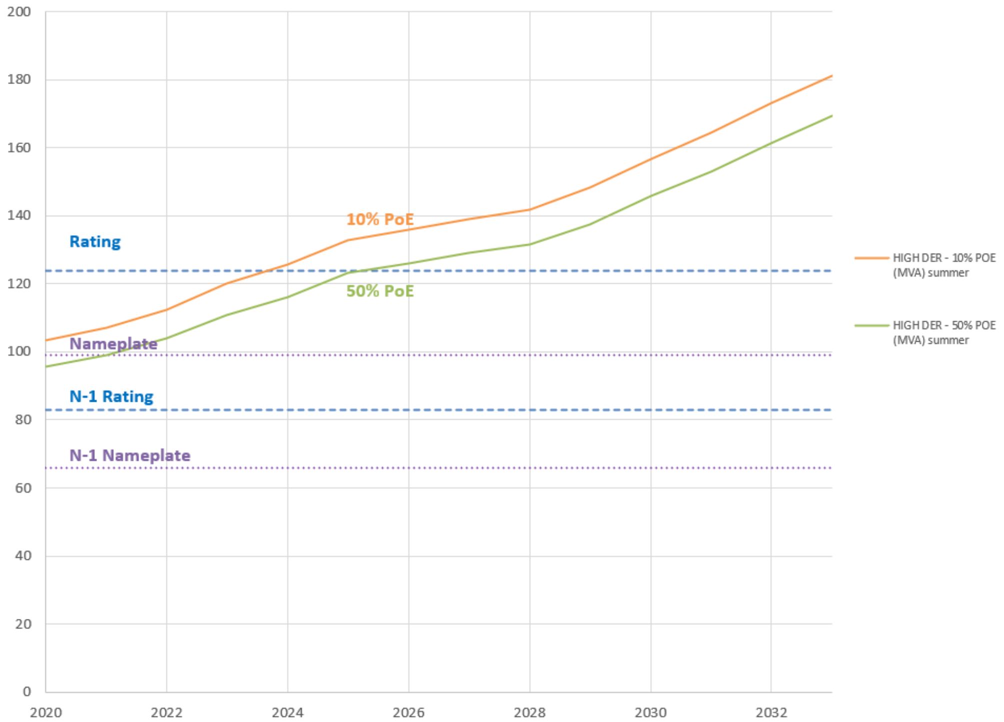


Figure 8 Werribee Substation (WBE) Summer Loading Forecast (MVA)

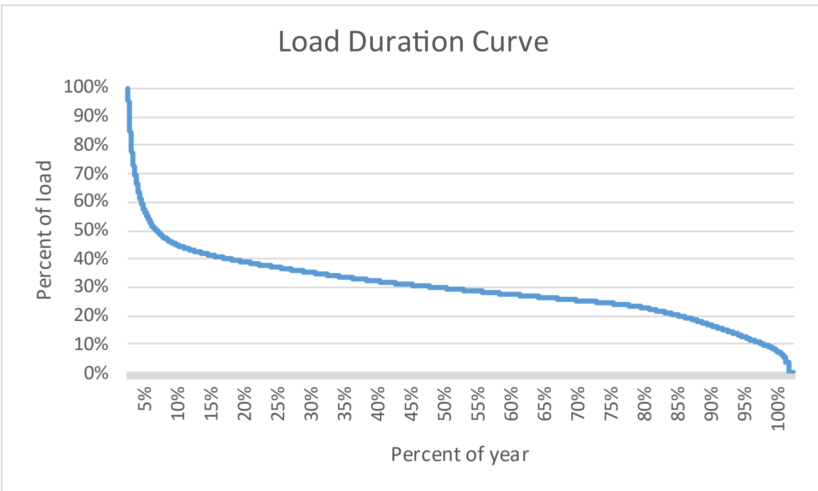


Figure 9 MVA Load Duration Curve Werribee Substation (WBE)

## 3.5 Network Risk

As shown above in the peak demand forecasts, electrical demand growth in the western growth corridor area is expected to continue in the short to medium term (and beyond). Each exceedance of N-1 capacity can result in failure to meet the required level of supply during contingency events in addition to limiting maintenance and inspection tasks. This is an immediate issue for TNA, WBE, LV and MLN.

As peak demands increase, the N cyclic thermal ratings of all substations surrounding MTC will be exceeded, with a major concern in the Werribee area where overloading is likely to occur within the next 2 to 3 years. Unaddressed overloads beyond the cyclic N ratings are likely to see interruptions to customer supply occur, either unplanned or on a rotating load shedding arrangement.

Table 4 details the combined NNO energy support required at WBE, LV, MLN and TNA substations. This is forecast as 15.9 MWh in 2025/26 and increases to 58.8 MWh by 2030/31 based on a probabilistic estimate of energy at risk (50% POE, N-1 forecast).

Table 4 Forecast duration of load at risk under system normal conditions (WBE+LV+MLN+TNA, 50% POE Central, N-1)

| Combined Cyclic Capacity (MVA) | Year | Forecast (MVA) | Load at Risk (MVA) | Hours above limit pa | MWh above limit pa |
|---|---|---|---|---|---|
| **337.6** | **2025/26** | **454.2** | **116.6** | **311.0** | **15.9** |
| | **2026/27** | **459.1** | **121.5** | **327.5** | **17.4** |
| | **2027/28** | **464.1** | **126.5** | **354.5** | **19.3** |
| | **2028/29** | **470.7** | **133.1** | **454.3** | **23.4** |
| | **2029/30** | **488.9** | **151.3** | **683.5** | **35.5** |
| | **2030/31** | **513.3** | **175.7** | **1061.8** | **58.8** |

# 4 Credible Network Solutions

To provide a benchmark of costing for these connection works, some possible network solutions will be discussed in this section. This allows derivation of potential deferred augmentation charges that could be available for any credible non-network or SAPS options. This is discussed further in section 5. There are no customer-site or local-to-site network options that are credible network solutions.

## 4.1 Credible Network Options

The network risk in Table 1 must be addressed. To not do so will compromise our ability to provide supply to the 2 new applications for large loads as required by chapter 5 of the NER.

Table 5 is a summary of three credible network options that can address the identified need. Note that no options here provide an N-1 solution for the new loads. However, all options will provide a minimal alternative supply that while not able to run production, will give limited power to each site.

Table 5 Credible network options and costs

| Option | Description | Comments | Capex Value |
|---|---|---|---|
| **1** | New feeders from MLN and associated zone substation upgrade | • 19km of 22kV distribution line work<br>• Substation upgrade in 2027<br>• ATS upgrade not required as connected to Deer Park Terminal station (DPTS) sub-transmission network.<br>Construction period 2025* | $ 34m |
| **2** | New feeders from MLN & TNA, and associated zone substation upgrades | • 30km of 22kV distribution line work on feeders from MLN and TNA<br>• MLN upgrade; including new main transformer, in 2029<br>• TNA upgrade; including new main transformer, in 2030<br>• ATS upgrade; including new main transformer, brought forward 1 year.<br>Construction period 2025* | $ 56m |
| **3** | New zone substation in Mount Cottrell area | • Single transformer<br>• Connected to Deer Park Terminal station (DPTS) sub-transmission network<br>Construction period 2025* | $ 16m |
| * Targeted commissioning date is Quarter 4 2025 | | | |

Utilising the existing transmission network from DPTS, construction of a single transformer substation and associated feeder bays in proximity to the loads will give a more efficient and prudent result that will provide capacity for new customer connections with the supply quality required.

Therefore, in the event of no non-network solutions that would be a more efficient solution, Option 3 would be the preferred option.

# 5 Assumptions and Methodologies

## 5.1 Demand Forecasts

The 'High DER' demand forecasts referred to in this report are sourced from our 2023 Distribution Annual Planning Report (DAPR). Similarly, the 'Central' demand forecasts referred to within this report are based on the 'High DER' forecast with the addition of high confidence non-committed loads where applicable.

## 5.2 Financial model inputs

In preparing our costs we have assumed:

- That the costs for works estimated by us will be within an accuracy of ± 25%. They are prepared by our internal estimators from standard component estimates.
- The models are evaluated over a period of 15 years.
- Calculations for annual deferral values of projects are based on our regulated pre-tax real Weighted Average Cost of Capital (WACC) as prescribed by the AER for the current regulatory period. The identified need described in this Non-Network Options Report occurs in the 2021-2026 regulatory reset period, where a WACC of 2.75% has been used to demonstrate an approximate WACC-driven deferral value below.

## 5.3 Potential deferred augmentation charges

We have estimated the capital cost of the preferred network option to within ± 25% of estimation accuracy.

Using this basis as a guide, a deferral of the preferred network option will represent a saving of approximately $0.4m per annum, assuming the same reliability outcomes are maintained as with the preferred network option.

Please note that we do not represent this to be a precise deferral cost available to a non-network proponent, but it is adequate to guide in determining the viability of a non-network proposal.

Timing required for any non-network options to defer the network solution is by Quarter 4 2025.

## 5.4 Minimum requirements that will form part of our assessment

The requirements for a viable non-network option to address the benefits provided by a network solution would be as follows;

• maintain supply to the new connections within acceptable limits of quality;

• be capable of alleviating estimated capacity shortfalls on the existing infrastructure during system normal and credible system abnormal (feeder outage) scenarios, noting that the existing supply is very limited.

# 6 Non-Network Options Summary

## 6.1 Evaluation of Non-Network Solutions

We investigated three approaches to a non-network solution, Onsite generation, offsite solutions and customer driven solutions. The outcomes are ranked in Table 6 against a 3-stage rating; criterion likely to be met (Green), Criterion not fully met or uncertainty exists (yellow), and, criterion not met (red).

Table 6 Assessment of non-network solutions

| Options | Assessment result | | | |
|---|---|---|---|---|
| | Fit | Technical | Commercial | Timing |
| **1 Onsite generation** | | | | |
| 1.1 Gas turbine | | | | |
| 1.2 Generation* and battery storage | | | | |
| **2 Off site solution** | | | | |
| 2.1 Aggregation / offsite generation | | | | |
| **3 Customer driven** | | | | |
| 3.1 Power factor correction | | | | |
| 3.2 Energy Efficiency | | | | |
| 3.3 Curtailment | | | | |

* Solar, wind or any non-network technology

Our investigations found that:

- The nature of the loads removed any potential for a credible customer driven solution that is acceptable to the customer.
- Offsite solutions require large expenditure to upgrade the network between the solution and the load, leaving little investment to actually address the energy needs.
- On site generation with battery storage is impractical given that the local energy source provides any direct consumption by the load as well as charging batteries for time offset consumption.
- On site generation such as a gas turbine could work technically. It is uncertain how this would align with the Victorian Government's roadmap away from gas, but in any case is unlikely to be available in a reasonable time period and is well over the cost of the preferred network solution.

These findings show that there are no credible non-network solutions that would be a more efficient solution than the preferred network solution of section 4.

# 7 Non Network Options Determination

## 7.1 Statement of Determination

As discussed in section 6, we believe that there are reasonable grounds to make a determination in accordance with Clause 5.17.4 (c) of the NER.

Accordingly, we now determine that there are no non-network or SAPS options that could form a credible option that is at least or more efficient than the preferred network solution of establishing a new zone substation near the load site.

## 7.2 Next steps

We will carry out steps in accordance with the RIT-D process to progress assessment of the preferred solution to meet the identified need. Figure 10 shows the RIT-D process, and we assess that we are now at point A.

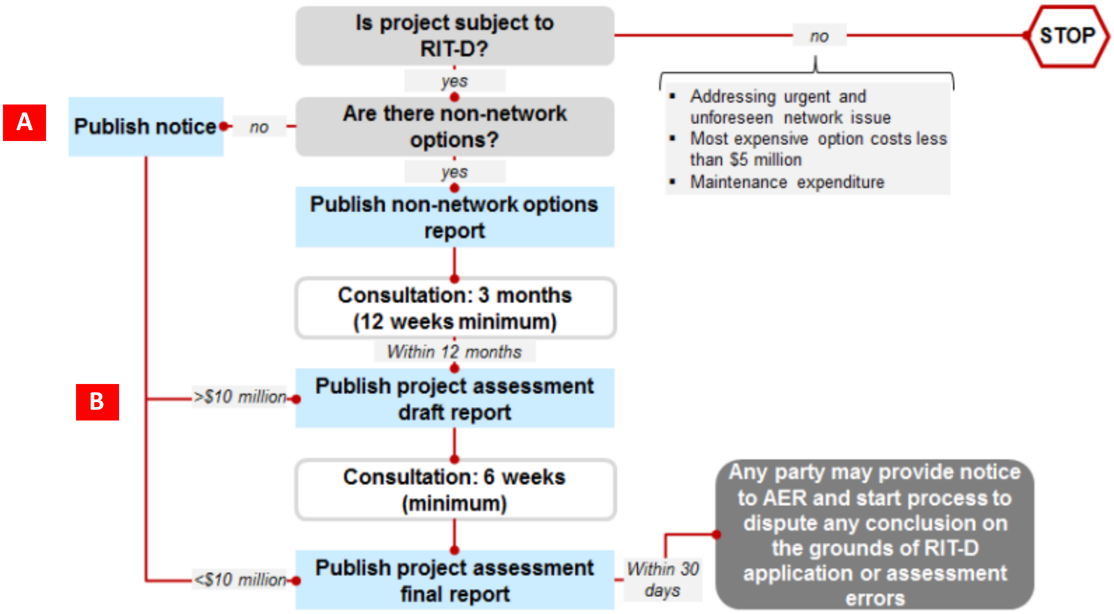


Figure 10 RIT-D process summary (from Fig 1 of the AER's Application guidelines, Aug 2022)

The next step is to publish this determination and this is targeted for publishing in October 2024.

We will then commence the project assessment draft report (PADR) (shown as point B in Figure 10). The costings associated with that work are subject to a $12m threshold[2] (of DNSP costs) that will then determine whether we carry out the publishing of a project assessment draft report (PADR) or possibly proceed directly to publishing the project assessment final report (PAFR). In any case we aim to have this step completed in October 2024.

[2] https://www.aer.gov.au/industry/registers/resources/reviews/cost-thresholds-review-regulatory-investment-tests-2021

# 8 Compliance statement

This Non-Network Options Report complies with the requirements of NER section 5.17.4(e) as demonstrated below:

| | Requirement | Location |
|---|---|---|
| 1 | Description of the identified need. | **3.1** |
| 2 | The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary. | **2, 3** |
| 3 | If available, the relevant annual deferred augmentation charge associated with the identified need. | **5.3** |
| 4 | The technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; (iii) contribution to power system security or reliability; (iv) contribution to power system fault levels as determined under clause 4.6.1; and (v) the operating profile. | **3** |
| 5 | A summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options and non-network options. | **Table 5, Table 6** |
| 6 | For each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on: (i) a technical definition or characteristics of the option; (ii) the estimated construction timetable and commissioning date (where relevant); and (iii) the total indicative cost (including capital and operating costs). | **Table 5** |

For any enquiries with this determination, please contact:

Attention: Mount Cottrell Stage 1
ritdenquiries@powercor.com.au

# 9 References


AEMC. (2024, September 05. *National Electricity Rules - Chapter 5*. https://energy-rules.aemc.gov.au/ner/609/499010#5

Australian Energy Regulator. (2021, November 19). *Cost thresholds review for the regulatory investment tests*. https://www.aer.gov.au/industry/registers/resources/reviews/cost-thresholds-review-regulatory-investment-tests-2021

Australian Energy Regulator. (2022). *Application guidelines - Regulatory investment test for distribution*. AER. https://www.aer.gov.au/documents/aer-rit-d-application-guidelines-august-2022

CitiPower and Powercor. (2023). *Distribution Annual Planning Report*. https://www.powercor.com.au/network-planning-and-projects/network-planning/

# 10 Definitions

| Term | Definition |
|---|---|
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| DNSP | Distribution Network Service Provider |
| HV | High Voltage |
| N rating | Capacity available with network operating with all elements in service |
| N-1 rating | Capacity available with network operating with one element unavailable for service |
| NER | National Electricity Rules (Version 216) |
| PoE 50 | The 50% PoE demand forecast relates to maximum demand corresponding to an average maximum temperature that will be exceeded, on average, once every two years |
| RIT-D | Regulatory Investment Test for Distribution |
| VCR | Value of customer reliability |