Project Assessment Final Report

Connection of large customers in the Mt Cottrell area

October 2024

Contents

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. For further information please refer to the Notice of Determination of No Non-Network Options entitled "Connection of large customers in the Mt Cottrell area".

This Final Project Assessment Report has been prepared in accordance with the Regulatory Investment Test for Distribution (**RIT-D**) requirements of the National Electricity Rules (**NER**) clause 5.17.4[1].

1 Version 216 of the Rules, clause 5.17.4.

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 will 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 currently supply the requested loads.

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

Having a project value for a network solution in excess of $6m, this project meets the criteria of clause 5.17.3 of the NER and as such is subject to a RIT-D.[2]

As our costs for the preferred option are less than $12m, the Draft Project Assessment Report stage is not required. We have elected to publish this document as the Final Project Assessment Report, which is the final stage of the RIT-D process for this project.

[2] 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 are targeted to be commissioned by Quarter 4 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 the table below.

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 Special consideration for solutions connecting to existing zone substations

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.

Any solutions that interface with the existing distribution network need to take into account the physical limitations of the lines in the area. Upgraded infrastructure and or new circuits will be required to transport the required loads while keeping supply quality within limits to the site. Any options used to connect the new loads to the upgraded existing distribution network will drive augmentation of one or more surrounding substations. The impacts of the new connections on each surrounding substation are shown in Table 2.

Using a 50% POE demand forecast, Table 2 provides a summary of exceedances of the N and N-1 ratings for each substation in this western growth area.

To represent handling of the new connections, two 'lumps' of load are used.

- The 18 MVA lump represents all the new connection load being supplied by one site.
- The 12 MVA lump is the larger section of the applications when split into two separable loads. This would allow one site to supply 12 MVA and another solution to supply the remaining 6 MVA. The impact of connecting the 6 MVA component is not considered to simplify analysis.

Table 2 Summary of rating exceedance timing

Substation	Exceed N-1 rating	Exceed N rating		
		No new load	12MVA lump	18MVA lump
MLN	now	2031	2029	2028
LV	now	2031	2027	2024
TNA	now	2033	2030	2025
WBE	now	2026	2024	now

4 Assumptions and Methodologies

4.1 Demand Forecasts

The demand forecasts are sourced from our 2023 Distribution Annual Planning Report (DAPR) with the addition of recent high confidence non-committed loads.

4.2 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%.
- 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.

4.3 Market Benefit Classes

NER clause 5.17.1(c)(4) requires Powercor as the RIT–D proponent to consider whether each credible option can deliver specified classes of market benefits. These are shown in Table 3 along with our assessment of whether the market benefit class is relevant and material for this project.

Table 3 Market Benefits; assessment of materiality

Specified Class[3]		Material	Comments
1	Changes in voluntary load curtailment	No	Load needs of customer make this class not relevant hence immaterial
2	Changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers	Yes	Refer to section 4.4, Counterfactual case
3	Changes in costs for parties, other than the RIT–D proponent, due to differences in: the timing of new plant, capital costs, and operating and maintenance costs	No	Customer needs and timing make this class not relevant hence immaterial
4	Differences in the timing of expenditure	No	Customer needs and timing make this class not relevant hence immaterial

[3] Items 1 to 6 are from NER clause 5.17.1(c)(4) and items 7 to 10 are from the AER RIT-D application guidelines (section 3.6)

Specified Class[3]		Material	Comments
5	Changes in load transfer capacity and the capacity of embedded generators to take up load	No	Nature of the project make this class not relevant hence immaterial
6	Any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the NEM	No	Nature of the project make this class not relevant hence immaterial
7	Changes in electrical energy losses	No	Consequences are real but not material in terms of comparison between options for network solutions. They have been included in the NPV calculations.
8	Changes in fuel consumption arising through different patterns of generation dispatch	No	Nature of the project make this class not relevant hence immaterial
9	Changes in ancillary services costs	No	Nature of the project make this class not relevant hence immaterial
10	Competition benefits	No	Nature of the project make this class not relevant hence immaterial

4.4 Counterfactual case

If no action is taken to address the identified need (the counterfactual case), customer reliability and hence energy delivery is at risk to the full extent as shown in Table 2. While this is not a realistic option if the identified need is to be met, it allows calculation of the worst-case scenario for defining market benefits associated with involuntary load shedding.

The Value of Customer Reliability (VCR) for the energy at risk of the required loads is modelled at $66.47 per kWh, taken from the table of *Very large business customers (in $/kWh - $2022) – for transmission/distribution* in the AER's 2022 VCR Annual Adjustment publication[4].

The load is assumed constant across the 15-year analysis period and is assumed to only include the load related to the customer applications currently received.

Figure 2 shows modelling results of the value of energy at risk using indexation applied to 2022 rates.

[4] https://www.aer.gov.au/system/files/2023-12/2023%20VCR%20Annual%20Adjustment%20update%20summary%2816100739.1%29.pdf

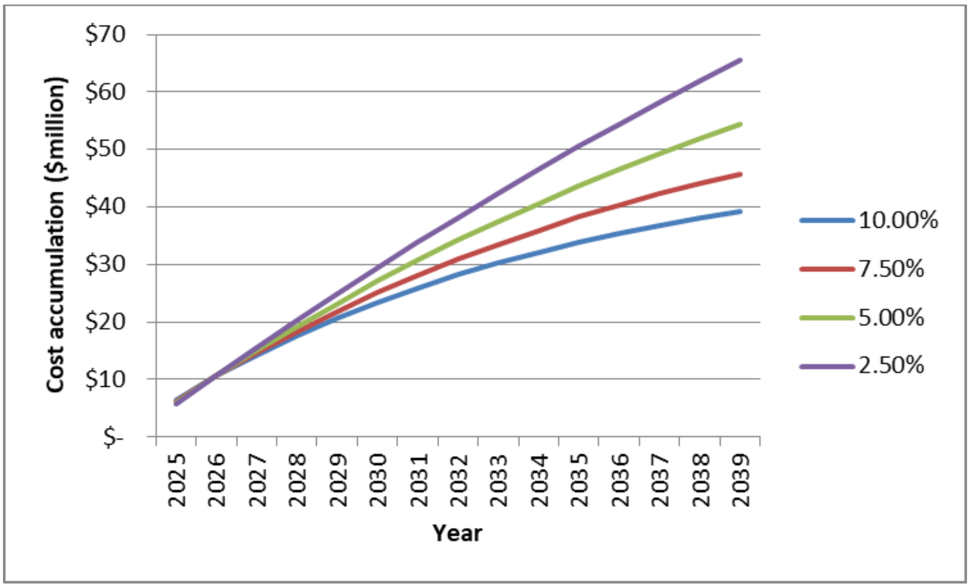

Figure 2 Accumulated cost of counterfactual case energy at risk (with indexation modelled between 2.5% and 10% pa)

The results show a range of accumulated cost of non-supply to customers from $40m to $65m.

5 Options to meet the identified needs

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

5.1 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 or non-network solution will be required to enable the connection of the loads.

5.2 Determination of no non-network options

In accordance with clause 5.17.4 of the NER, we have determined on reasonable grounds that there will not be a non-network option for the identified need.

We published this determination in October 2024 and, in accordance with NER clause 5.17.4(d), published a Notice of Determination of No Non-Network Options entitled "Connection of large customers in the Mt Cottrell area".

In that Notice, we determined that, in accordance with clause 5.17.4 (c), there are reasonable grounds that demonstrate that there will not be a non-network option that is a potential credible option for the RIT-D project to address the identified need.

5.3 Credible Network Options

Three possible network solutions to address the emerging load constraints in this area have been identified and are summarised in Table 4.

Table 4 Credible network options, timing and costs

Option	Description	Comments	Capital Value
(a)	New feeders from MLN and associated zone substation upgrade	• 19km of 22kV distribution line augmentation • Substation upgrade in 2027 • ATS upgrade not required as connected to Deer Park Terminal station (DPTS) sub-transmission network. Construction period 2025*	$ 34m
(b)	New feeders from MLN & TNA, and associated zone substation upgrades	• 30km of 22kV distribution augmentation on feeders from MLN and TNA • MLN upgrade; including new main transformer, in 2029 • TNA upgrade; including new main transformer, in 2030 • ATS upgrade; including new main	$ 56m

		transformer, brought forward 1 year. Construction period 2025*	
(c)	New zone substation in Mount Cottrell area	• Single transformer • Connected to Deer Park Terminal station (DPTS) sub-transmission network Construction period 2025*	$ 16m
* Targeted commissioning date is Quarter 4 2025			

The net present value of each of these options and comparison to the counterfactual case is discussed in Section 6.

6 Economic Modelling

In modelling the economic benefits of each of the options considered, the costs and benefits have been evaluated with reference to the counterfactual case. The modelled costs include the capital cost of implementing each option as well as the value of the estimated increase in losses associated with each option. Operations and maintenance costs for each option have not been included in the model as these are expected to be minimal for new assets over the 15-year modelling period and hence non-material.

It should be noted that, in accordance with our capital contributions policy, the proponents of the new load will be required to make capital contributions. The capital cost included in the modelling for each option is net of this contribution, on the grounds that this cost does not need to be recovered from our customers via the regulated charges.

Market benefits include the customer value of the additional energy that will be able to be supplied as a result of implementing any of the options. The net economic benefit of each option is calculated as the difference between the discounted value of the benefits and the costs over the 15-year modelling period.

In each case, a positive benefit over the counterfactual case of not investing in enabling these load connections is demonstrated.

6.1 Modelling results

a) The modelled financial results and subsequent preference ranking of the three options are shown in Table 5.

Table 5 Model results for 2.75% discount rate

Option		Cost	Benefit	NPV	Ranking
(a)	Supply from MLN substation	$ 11.1 M	$ 64.3 M	$ 53.2 M	1
(b)	Supply from MLN & TNA substations	$ 11.8 M	$ 64.3 M	$ 52.5 M	3
(c)	Build MTC Substation	$ 11.3 M	$ 64.3 M	$ 53.0 M	2

b) Sensitivity analyses applied to options

The results of modelling shown in Table 5 will be influenced by changes in assumptions used within the financial evaluation model. As a result, the robustness of assumptions is tested through scenario modelling.

(i) Changing the discount rate in response to national economic conditions. Two values of -0.5% pa and +1% pa have been used with results shown in Table 6.

Table 6 Scenario results for varying Discount Rate

Option	Discount rate:	2.25%	2.75%	3.75%	Ranking
(a)	Supply from MLN substation	$ 11.1 M	$ 11.1 M	$ 11.0 M	1
(b)	Supply from MLN & TNA substations	$ 11.6 M	$ 11.8 M	$ 11.6 M	3
(c)	Build MTC Substation	$ 11.4 M	$ 11.3 M	$ 11.3 M	2

The ranking of the options does not alter with credible movements of discount rate.

(ii) Returning the discount rate to 2.75%, the next variable to be modified is the load constraint timing for deferred substations. While the construction of the distribution feeders from the existing zone substations must be done immediately to enable the customer load connection, the substation upgrades detailed in Section 5.3 will be brought forward or deferred to match the timing of the appearance of the load constraints at these substations. Table 7 shows the effects on Options (a) and (b) by adjusting deferment timing of the zone substations by -2 years and +3 years. Note that this does not affect Option (c) as the substation is required to service the load in 2024.

Table 7 Scenario results for increased deferment of load constraint timing in options (a) & (b)

Option	deferred by:	-2 years	0 years	+3 years	Ranking
(a)	Supply from MLN substation	$ 11.1 M	$ 11.1 M	$ 11.0 M	1
(b)	Supply from MLN & TNA substations	$ 11.9 M	$ 11.8 M	$ 11.6 M	3
(c)	Build MTC Substation	$ 11.3 M	$ 11.3 M	$ 11.3 M	2

Supply from MLN substation, Option (a) retains its status of preferred option under these scenarios.

(iii) Altering cost inputs for construction costs. Substations have a history of more predictable pricing than lines. Lines are more volatile given the distance they travel, varying soil conditions and infrastructure that may be in proximity. As such, substation cost variances will be +/- 10% and line costs will use variances of -5% and +25%.

Table 8 Scenario results for variations in cost inputs

Option	Cost base variation:	SS -10%, L -5%	SS 0%, L 0%	SS 10%, L 25%	Ranking
(a)	Supply from MLN substation	$ 10.6 M	$ 11.1 M	$ 13.3 M	2
(b)	Supply from MLN & TNA substations	$ 11.3 M	$ 11.8 M	$ 13.7 M	3
(c)	Build MTC Substation	$ 10.3 M	$ 11.3 M	$ 12.4 M	1

Depending on the assumptions chosen, the preferred option may be either Option (a) or Option (c).

c) Discussion on results of modelling

When all scenarios are considered, there is only $80,000 difference between the two lowest cost options (a) and (c). This represents 0.7% difference which is well inside the accuracy band of 10% that the costing models use.

As a result, we will treat the options as equal, requiring further considerations to be taken into account to determine a preferred option.

6.2 Other considerations

Given the inability of the modelling in section 6.1 to determine a clear preferred option, the following issues have been considered:

1. Future demand growth

Table 2 lists the long-term forecast demand constraint timing. This will eventually necessitate the installation of additional transformer capacity beyond what is required under any of the options considered in this RIT-D. Specifically, it is expected that the zone substations at Laverton and Werribee will also require augmentation if there is no substation constructed at Mt Cottrell. Both these sites are somewhat constrained physically and augmentation is likely to be expensive. Establishment of MTC zone substation to meet the currently identified need would provide an additional option to meet future load growth, through the addition of a second transformer at an appropriate time, on a site that is able to be planned in a cost-effective manner.

While the works necessary to meet this future demand will be the subject of a future RIT-D process we have made some estimates of the likely costs to inform our consideration of the preferred option to meet the current network need. Table 9 provides a high-level estimate of the NPV of all the current and future augmentation costs for each of the three credible options, in light of the expected future load growth.

Table 9 Discount rate scenario results for forward planning assessment

Option		Discount rate:	**2.75%**	**Ranking**
(a)	Supply from MLN substation		$ 29 M	2
(b)	Supply from MLN & TNA substations		$ 30 M	3
(c)	Build MTC Substation		$ 27 M	1

When future load growth is considered, Option (c), to establish MTC zone substation, may be a preferred option.

2. Customer supply reliability

Distribution feeders are inherently less reliable than transformers and substation assets. Connection of the new Mt Cottrell area load to existing substations will subject the new loads to the level of reliability associated with distribution lines that are longer than the lines that will be necessary to supply the loads from a more centrally located substation. Further, if the loads are to be supplied from only one existing substation (Option (a)) there is less diversification of the reliability risk than in the case of Option (b).

Qualitatively, this makes a new MTC zone substation the preferred option with Option (a) being the least preferred option.

6.3 Preferred option

Clause 5.17.1 (b) of the NER defines the principle that the preferred option is to:

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

While under almost all scenarios Option (a) is the lowest cost option, there is negligible difference in the net economic benefit of any of the options, such that small variations in cost could change the preferred option ranking.

When future load growth and the qualitative impact of the inherent reliability of each option is considered, Option (c), to establish a new Mt Cottrell zone substation becomes preferred.

Option (c) is identified as the preferred option which addresses the identified need in the most efficient manner and produces a net positive result when compared to the counterfactual case.

7 Satisfaction of RIT-D

The proposed preferred option as summarised in Section 6.3, satisfies the RIT-D. This statement is made based on the detailed analysis set out in this report.

Table 10 checklist of regulatory compliance

Rules clause	Requirement	Section of this report
5.17.4(j)(1)	Description of the identified need for the investment	Section 3
5.17.4(j)(2)	The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary)	Section 4
5.17.4(j)(3)	If applicable, a summary of, and commentary on, the submissions on the non-network options report	Section 5.2 & Appendix A
5.17.4(j)(4)	Description of each credible option assessed	Section 5
5.17.4(j)(5)	Where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option	Not applicable
5.17.4(j)(6)	A quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	Section 6
5.17.4(j)(7)	A detailed description of the methodologies used in quantifying each class of cost and market benefit	Section 6
5.17.4(j)(8)	Where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	Not applicable
5.17.4(j)(9)	The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	Section 6.1
5.17.4(j)(10)	The identification of the proposed preferred option	Section 6.3
5.17.4(j)(11)	For the proposed preferred option, the RIT-D proponent must provide:	
	• details of the technical characteristics	Section 5.3
	• the estimated construction timetable and commissioning date (where relevant)	Section 5.3
	• the indicative capital and operating cost (where relevant)	Section 5.3
	• a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution	Section 7
	• if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	Not applicable

This document constitutes our Final Project Assessment Report and details the option intended to be implemented.

8 Powercor Contact

Further information can be provided electronically to the email address provided below:

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

Alternatively, submissions may be lodged by mail to the following address:

Attention: Mount Cottrell Stage 1

Powercor Australia Limited

Locked Bag 14090 Melbourne Vic 8001.

9 References

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

AEMC. (2024, September 5). *National Electricity Rules - Clause 5.17.4*. https://energy-rules.aemc.gov.au/ner/609/499184#5.17.4

AEMC. (2024, September 5). *National Electricity Rules - Clause 5.17.1(c)*. https://energy-rules.aemc.gov.au/ner/609/499181#5.17.1

Australian Energy Regulator. (2021, November 19). *Cost thresholds review for the regulatory investment tests 2021*. Australian Energy Regulator (AER). 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

Australian Energy Regulator. (2023). *2023 Values of Customer Reliability Annual Adjustment*. AER. https://www.aer.gov.au/system/files/2023-12/2023%20VCR%20Annual%20Adjustment%20update%20summary%2816100739.1%29.pdf

10 Definitions

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATS	Altona Terminal Station
DNSPs	Distribution Network Service Providers
DPTS	Deer Park Terminal Station
LV	Laverton zone substation
MLN	Melton zone substation
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 – removal of an element in this configuration will likely interrupt supply to customers
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
TNA	Truganina zone substation
VCR	Value of customer reliability
WBE	Werribee zone substation