Powercor AUSTRALIA

Final Project Assessment Report

Supplying the Mt Cottrell area

November 2026

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1 Introduction

This report concerns electrical supply in the Mount Cottrell area and its surrounding locales. This area includes Truganina to the east, Werribee to the south and Melton to the north. The area is located in Melbourne's western growth corridor, and area of rapidly growing urban subdivisions and new commercial / industrial load centres.

In publishing the Draft Project Assessment Report (**DPAR**), we have in accordance with NER clause 5.17.4(i), determined the preferred network option is to upgrade Mount Cottrell Zone Substation (**MTC**).

This Final Project Assessment Report (**FPAR**) 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 236 of the Rules, clause 5.17.4.

2 Overview

2.1 Background

Melbourne's western growth corridor is an area of rapidly developing urban subdivisions and new commercial / industrial load centres.

The area of interest for this FPAR is Mount Cottrell and surrounds. This includes the established growth areas of Truganina to the east, Werribee to the south and Melton to the north.

A new substation at MTC was established, driven by new customer load. The establishment of MTC was the subject of a separate completed RIT-D process. It was established as a single transformer station, designed to supply a limited number of large industrial customers.

The new substation MTC is situated between four existing substations being Werribee (**WBE**), Laverton (**LV**), Truganina (**TNA**) and Melton (**MLN**). MLN and TNA are currently supplied by Deer Park Terminal Station (**DPTS**), whereas WBE and LV are supplied by Altona Terminal Station West (**ATS west**).

A map showing the area and relevant substations is shown in Figure 1.

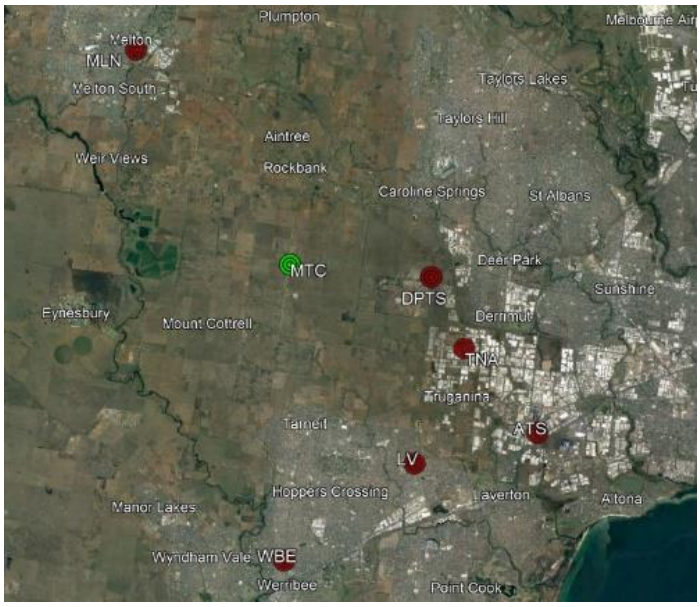


Figure 1 Mount Cottrell (MTC) supply area

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

Having a project value greater than $7 million, this project meets the criteria of clause 5.17.3 of the NER. As such it is subject to a RIT-D.[2]

Whilst the cost of the preferred option is less than $14 million, we still opted to publish a DPAR. The FPAR, published under 5.17.4(o) of the NER, represents the final stage of the RIT-D process.

[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 NER, we must connect customers, and in doing so, must also achieve specified performance standards. Customers must be connected to the network such that they do not adversely impact other network customers. The identified need therefore for this project is to 'provide adequate customer supply' to ensure we remain compliant with our NER obligations.

The three substations, WBE, LV and MLN are all facing load constraints. This prevents them from being able to supply the forecast future load in the area and unable to accept transfer requests between them to meet operational needs. ATS-west is also approaching load constraints, creating load at risk at all four sites.

MTC was built to supply known commercial loads. It does not have adequate capacity to accept additional load transferred from surrounding substations. Consequently, as designed, it cannot alleviate the emerging constraints at ATS-west.

The factors driving the need for this project are emerging no prior outage ('N') hours at risk at WBE, in addition to significant levels of single outage ('N-1') hours at risk at TNA and ATS-west.

3.2 Quantification of identified need through load forecasting

Each substation has:

- a nameplate and cyclic rating when all components are in service in a normal operating configuration (N)
- a nameplate and cyclic rating 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. This is achieved through permitting managed periods of overloading (cycling) that allows more energy to be delivered at a rate higher than full time loading limitations. This situation cannot be permanent however without causing damage to equipment.

The forecast charts show two probabilities of load growth (probability of exceedance (**POE**)):

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

Load forecasts and typical consumption profiles are shown in the following sections, using data sourced from the 2023 Distribution Annual Planning Report (**DAPR**). A 'Central' load forecast was formulated for zone substations where there was high confidence customers were looking to connect. The 'Central' load forecast is based on the 'High DER' load forecast as per the 2023 DAPR, with the addition of these diversified high confidence loads.

Summary of impacts of forecasts

As shown in the DAPR, electrical demand growth in the western growth corridor area is expected to continue to grow in the short to medium term. Each exceedance of N-1 capacity can potentially result in quality of supply standards being compromised during system normal configuration, as well as limiting our ability to carry out maintenance and inspection tasks. This is an immediate issue for WBE, LV and MLN.

Table 1 provides a summary of exceedances of the N and N-1 ratings for each substation.

Table 1 Summary of rating exceedance timing (50% POE)

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

As peak demand increases, the N cyclic thermal ratings of all substations surrounding MTC will be exceeded. The concern is greatest for WBE where overloading is expected in the next two to three years. Unaddressed overloads beyond the cyclic N ratings are likely to result in customer interruptions.

4 Assumptions and Methodologies

4.1 Demand forecasts

The demand forecasts are sourced from our DAPR. They have been augmented with information on recent high confidence non-committed loads.

4.2 Financial model inputs

Costs have been prepared assuming:

- estimated costs are within an accuracy of ± 10 per cent
- 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**) prescribed by the Australian Energy Regulator (**AER**) for the current regulatory period. The identified need described in this report occurs in the 2021-2026 regulatory reset period, where a WACC of 2.75 per cent has been used to demonstrate an approximate WACC-driven deferral value.

4.3 Market benefit classes

Clause 5.17.1(c)(4) of the NER requires the RIT–D proponent to consider whether each credible option can deliver specified classes of market benefit. The assessment of each benefit is shown in Table 2 alongside whether it is relevant, and material, for meeting the identified need.

Table 2 Market benefits; assessment of materiality

Specified Class[3]		Material	Comments
1	Changes in voluntary load curtailment	No	The load needs of connected customer make this class irrelevant and 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/or operating and maintenance costs	No	Customer needs and timing make this class of benefit irrelevant and immaterial
4	Differences in the timing of expenditure	No	Customer needs and timing make this class of benefit irrelevant and immaterial
5	Changes in load transfer capacity and the capacity of embedded generators to take up load	No	Nature of the project make this class benefit irrelevant and 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
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 of benefit irrelevant and immaterial
7	Changes in electrical energy losses	No	Consequences are real but immaterial 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 of benefit irrelevant and immaterial
9	Changes in ancillary services costs	No	Nature of the project make this class of benefit irrelevant and immaterial
10	Competition benefits	No	Nature of the project make this class of benefit irrelevant and immaterial

4.4 Counterfactual case

If no action is taken to address the identified need (the counterfactual case), customer reliability will be compromised and energy at risk follow. While the counterfactual option is not realistic if the identified need is to be met, it allows calculation allows a worst-case scenario for defining market benefits associated with involuntary load shedding.

The value of customer reliability (**VCR**) for the energy at risk is modelled using the values in Table 3:

Table 3 Value of customer reliability by sector[4]

Sector	$/kWh
Residential	$ 25.13
Agricultural	$ 44.40
Commercial	$ 52.20
Industrial	$ 74.79

Given that the number of customers, their sector type, and connecting to each substation is known, a mathematically derived VCR for each substation can calculated. These values are shown in Table 4.

[4] https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20customer%20reliability%20%20update%20summary%20-%20December%202022.pdf

Table 4 VCR by substation ($/kWh)

Zone substation	MLN	LV	TNA	WBE	DPTS	ATS
ZSS VCR ($/kWh)	$ 37.73	$ 38.87	$ 51.06	$ 38.71	$ 46.11	$ 39.27

When the values in Table 4 are applied to substation forecasts over the next 15 years, a total VCR for each substation can be estimated. The results use a discount rate of 2.75 per cent (including a total of the affected substations).

Table 5 Discounted VCR modelled across the 15 year period

Substation	$M
MLN	50.7
WBE	294.6
TNA	21.0
LV	41.6
TOTAL	**408.0**

The significantly higher VCR for WBE in Table 5 reflects the almost impending 'N' constraint.

Adjusting the discount rate between 1.5 and 4.5 per cent provides an accumulated value across the modelling period as shown in Figure 2.

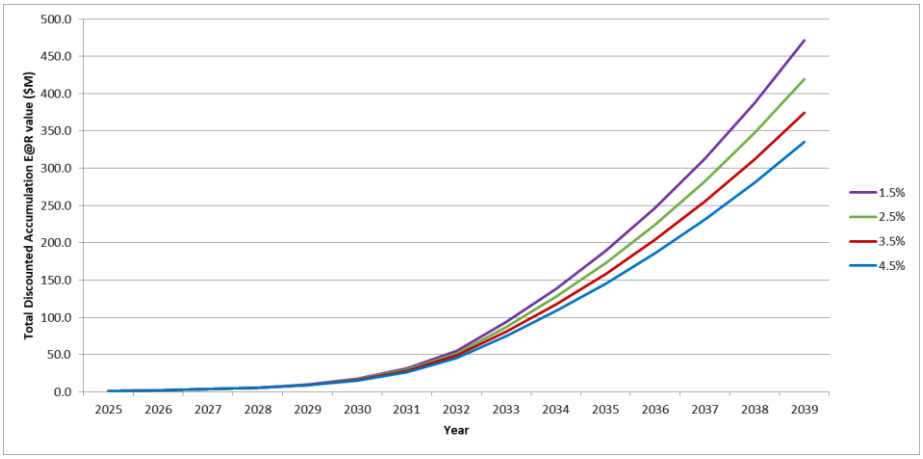


Figure 2 Accumulated cost of counterfactual case energy at risk

The results of discount rate modelling provides a range of accumulated cost of non-supply to customers between $335 to $470 million. Using the discount rate from section **Error! Reference source not found.**, gives a value of $408 million. It is this value that is used in section 6.1.

5 Options to meet the identified needs

The network risks in section **Error! Reference source not found.**, and quantified in section 4, require addressing. Failing to do so will compromise our ability to provide supply to existing and new customers, as required by chapter 5 of the NER.

5.1 Possible solutions

Future connections to the existing network are not possible given demand forecasts lead to constraints at all substations within the surrounding area. Some form of augmentation is therefore required.

5.2 Determination of no non-network options

In accordance with clause 5.17.4 of the NER, a RIT-D proponent must screen for non-network options to address the identified need. This process was undertaken in August 2024 and, in accordance with NER clause 5.17.4(b), a non-network options screening report entitled *Supplying the Mount Cottrell Area* was published.

We did not receive any non-network option submissions that addressed the identified need that:

- provided a potential credible non-network option or
- formed a significant part of a potential credible non-network option.

The methodologies and assumptions used to arrive at this conclusion are presented in Appendix A.

5.3 Credible network options

Three network solutions have been identified to address the emerging load constraints.

a) Upgrade all surrounding substation sites

This option allows investment deferral via the upgrade of individual substations as emerging constraints at discrete sites are reached. There are difficulties with expansion at some sites, but for the purposes of this analysis, it is assumed that these problems can be resolved

This option does not transfer load from ATS west hence the timing of its upgrade is not altered.

There is a need to upgrade connecting 22 kV feeders between substations to provide support to each other and to provide capacity to Mt Cottrell area. MTC remains dedicated to industrial / commercial large loads.

b) Upgrade MTC to become a two transformer station and transfer other substation loads to it

This option installs a second 25MVA transformer at MTC and accompanying distribution feeder connection points.

MTC's location minimises distribution connection work for inter substation load support. Transfer of load from other three substations alleviate constraints across the three existing substations. MTC is connected to DPTS and load transferred to it assist in alleviating load constraint at ATS-west. This permits deferral of the proposed ATS-west upgrade.

c) Construct a new substation at Rockbank or Tarneit and transfer other substation loads to it.

Our estimates for a Rockbank East substation (**RBE**) demonstrate it was the lowest cost option if building a new two transformer station. The option does require a land purchase and construction of a new two transformer substation. There are also associated transmission, and distribution, connection works to connect the new substation to the grid.

Like option b, transfer of load from other 3 substations to this new substation alleviates constraints at the three existing substations. It also permits deferral of the upgrade at ATS-west.

Table 6 is a summary of these three credible network options that can address the identified need.

Table 6 Costing and Timing of Credible Network Options

Option	Description	Comments	Capital value
(a)	Upgrade WBE, LV and MLN	• three substation sites to be upgraded as per constraint timing in Table 1 • distribution mains into new developments • no change to timing of ATS-west investment	$32.6m - $39.8m
(b)	Upgrade MTC	• one substation to be upgraded to add a second transformer bay and feeder circuit bays (2026) • distribution network ties to be added (noting this brings forward distribution mains into new developments) (2026) • transfer load from TNA, WBE, LV and MLN to MTC. This creates load transfers from ATS-west to DPTS, deferring TS upgrades	$15.9m - $19.5m
(c)	New substation at RBE	• purchase land (2024) • build new 2 transformer substation (2025) • build connecting transmission and distribution power lines (2025) • transfer load from ATS to DPTS deferring TS upgrades by one year	$34.2m - $41.8m

The net present value of each option, and its comparison to the counterfactual, is discussed in section 6.

Network studies show to manage short and long term growth, an upgrade of MTC is the preferred option as it permits transfer of loads from other substations and accommodates continued local development of commercial / industrial and residential connections in the Mount Cottrell area.

6 Economic modelling

In modelling the economic benefits of each of option, the costs and benefits have been evaluated by reference to the counterfactual case. The modelled costs include the capital cost of implementing each option. Operation and maintenance costs have not been included as these are expected to be minimal for new assets over the 15-year modelling period and are similar across the options. Market benefits include the customer value of the additional energy that will be able to be supplied due to implementation of 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 a 15-year period.

Each option demonstrates a positive benefit over the counterfactual case.

6.1 Modelling results

a) The modelling outcomes and preference ranking of each option is presented in Table 7. The modelling uses the costs and timing from section 5.3 and the market benefits from section 4.4. As the identified need meets the definition of a reliability corrective action, clause 5.17.1 of the NER allows a negative net economic benefit. However, as the market benefits determined in section 4.4 are significant, all options are NPV positive.

Table 7 Model results for 2.75% discount rate

Option		Cost	Benefit	NPV	Ranking
(a)	Upgrade surrounding substations	$ 34.0m	$ 408m	$ 374m	3
(b)	Upgrade MTC substation	$ 16.8m	$ 408m	$ 391m	1
(c)	New substation RBE	$ 28.5m	$ 408m	$ 380m	2

Given the common market benefit value, sensitivity analyses are viewed only from a cost perspective.

6.2 Sensitivity analyses applied to options

The results of modelling shown in Table 7 can be impacted by changes in assumptions. Therefore the robustness of each key assumption has been tested through scenario analysis.

(i) Changing the discount rate in response to national economic conditions. Two values of -0.5 per cent per annum and +1 per cent per annum have been applied to the default rate. The results are shown in Table 8.

Table 8 Scenario results for varying discount rate

Option		Discount rate:	2.25%	2.75%	3.75%	Ranking
(a)	Upgrade surrounding substations		$ 35.3m	$ 34m	$ 31.6m	3
(b)	Upgrade MTC substation		$ 16.9m	$ 16.8m	$ 16.4m	1
(c)	New substation RBE		$ 28.6m	$ 28.5m	$ 28.1m	2

The ranking of the options does not alter with credible movements of discount rate, with option (b) remaining preferred.

(ii) The next sensitivity is the load constraint timing for deferrable substations. The substation upgrades detailed in Table 1 can be brought forward, or deferred, to allow assessment of constraint timing impacts. Table 9 shows the effects on options (a) by adjusting deferment timing of the zone substations by minus two years and plus three years. This sensitivity has little impact on options (b) and (c) as those options are required to service the load in 2025.

Table 9 Scenario results for increased deferment of load constraint timing in options (a) & (b)

Option		deferred by:	-2 years	0 years	+3 years	Ranking
(a)	Upgrade surrounding substations		$ 35.7m	$ 34m	$ 31.4m	3
(b)	Upgrade MTC substation		$ 17.2m	$ 16.8m	$ 16.8m	1
(c)	New substation RBE		$ 29.3m	$ 28.5m	$ 26.2m	2

Supply from MLN substation, option (b) retains its status of preferred option under this sensitivity.

(iii) Altering cost inputs for construction costs. Substations have a history of more predictable pricing than lines. As such, substation cost variances will be altered by +/- 10 per cent.

Table 10 Scenario results for variations in cost inputs

Option		Cost base variation:	-10%	base case	+10%	Ranking
(a)	Upgrade surrounding substations		$ 30.6m	$ 34m	$ 37.4m	3
(b)	Upgrade MTC substation		$ 15.1m	$ 16.8m	$ 18.4m	1
(c)	New substation RBE		$ 25.6m	$ 28.5m	$ 31.3m	2

The ranking of the options does not alter with credible movements of construction costs, with option (b) remaining as preferred.

6.3 Discussion on results of modelling

Option (b) is the preferred option under all sensitivities. Given the similarity of the works under each option, the sensitivities applied equally to all options. As a result costs moved with a similar percentage difference from the counterfactual.

The exception was sensitivity related to bringing forward or deferring augmentation under option (a), but the cost associated with the number of sites overwhelms the impact of discounted cashflow when compared to the other two options.

Option (c) will always be a higher cost than option (b) as it requires land purchase, control room and an extra transformer.

On average, option (b) has a 40 per cent lower cost than second ranked result, option (c).

6.4 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"*

The base case and all analyses modelled highlight that option (b) is the lowest cost option.

Therefore, Option (b) is identified as the preferred option.

7 Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D. This statement is made based on the analysis in this report.

Table 11 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 4.4 and Table 2
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
5.17.4(j)(10)	The identification of the proposed preferred option	Section 6.4
5.17.4(j)(11)	For the proposed preferred option, the RIT-D proponent must provide: • details of the technical characteristics • the estimated construction timetable and commissioning date (where relevant) • the indicative capital and operating cost (where relevant) • a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution • if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	 Section 3.2 Table 6 Table 12 Section 7 Not applicable

8 Conclusion

This document constitutes the FPAR. Further information can be provided electronically to the email address provided below:

Attention: Mount Cottrell Stage 2
ritdenquiries@powercor.com.au

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

Attention: Mount Cottrell Stage 2

Powercor Australia Limited

Locked Bag 14090 Melbourne Vic 8001.

9 APPENDIX

A Technical detail

A.1 Building block costs for financial modelling

Table 12 Cost building blocks (2022 pricing, capital costs unless noted otherwise))

Item	Unit cost	Comments	Life
Mini Zone substation	$ 30 M*	1 x 33 MVA transformer Switchgear, land, fencing, HV & LV connections	40+ yrs
Zone Substation	$ 45 M	2 x 33 MVA transformer Switchgear, land, fencing, HV & LV connections	40+ yrs
Additional transformer bay	$ 7.8 M	33 MVA transformer Switchgear, HV & LV connections	40+ yrs

** It is anticipated that one of the two mini zone substations would require significant additional cost to address the transmission connections, but this is ignored for now until model results indicate that the extra effort for accuracy is required.*

B Glossary of Terms

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