Emerging Load Constraint: Altona Terminal Station (West)

Project Assessment Draft Report

June 2025

Contents

1 Overview

The Altona Terminal station is located west of Melbourne in the area known as the Western Growth Corridor.

Altona Terminal Station West is the name used to describe a portion of the Altona Terminal Station that uses two dedicated transformers (and bays and associated equipment) as transmission connection assets to supply the local Powercor network.

The Altona Terminal Station West cannot take out one transformer for maintenance without overloading the second transformer, and, load forecasting has identified an emerging constraint with station load exceeding transformer short term loading capacity at times of peak demand.

Implementation of a solution must occur before the deterministic constraint timing of 2033. But using probabilistic planning processes, the cost to customers through the value of lost energy will exceed the cost of investment in 2029.

This report has identified one credible network options to mitigate the current and emerging constraints, with option (a), Construct an additional transformer bay, being the preferred economic solution.

In accordance with the Regulatory Investment Test for Transmission required by the National Electricity Rules, Powercor Australia now seeks feedback from stakeholders including registered participants, the Australian Energy Market Operator (**AEMO**), non-network providers, interested parties and persons on our demand side engagement register to provide feedback on this report. Submissions are due by 29 July 2025.

Powercor will consider all submissions received in response to this project assessment draft report before preparing a Project Assessment Conclusions Report.

2 Background

2.1 Configuration of the local transmission network

The physical locations of Altona Terminal Station (ATS) and Brooklyn Terminal Station (BLTS) are shown in Figure 1. ATS is a three transformer station supplied by the 220kV network from BLTS.

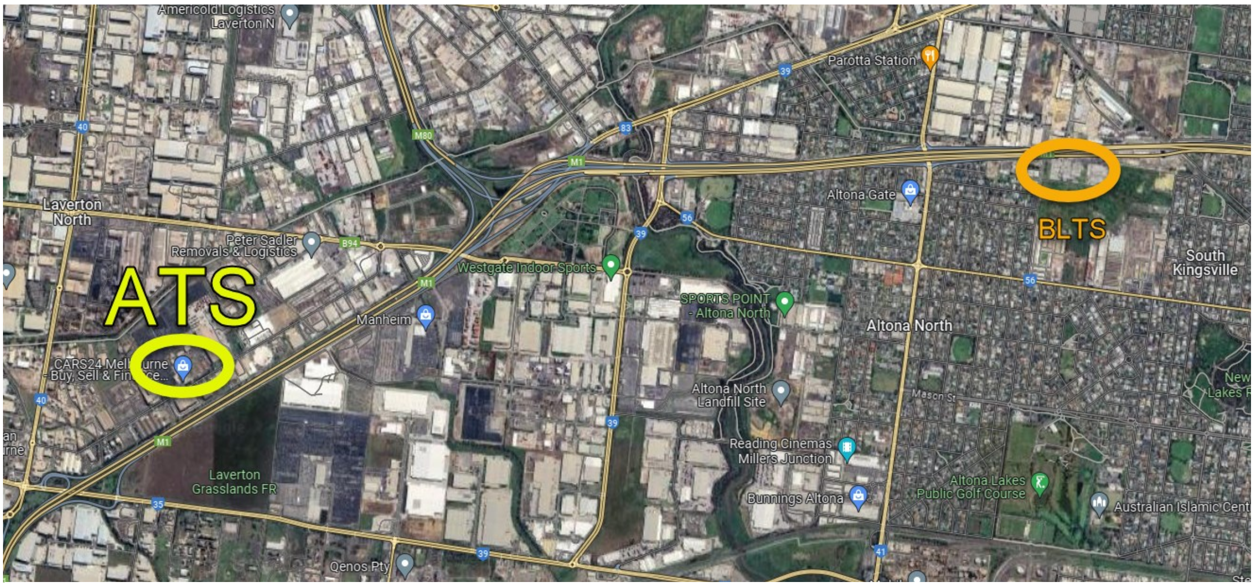

Figure 1 Location of Altona Terminal Station

For reliability and maintenance/operation of existing supply requirements, ATS is configured so that one transformer operates in parallel with the BLTS system and is isolated from the other two transformers via a permanently open 2-3 bus tie CB at ATS.

This electrically separates the secondaries of the two terminal stations creating two separate terminal stations that share physical space at ATS. These operational arrangements of the two virtual stations within ATS are referred to as ATS/BLTS and ATS West.

This report is focused on constraints of the ATS West system.

2.2 Altona Terminal Station West[1]

Altona Terminal Station West (ATS West) comprises two 150 MVA 220/66 kV transformers.

It supplies part of Melbourne's western growth corridor. This includes the areas of Laverton, Laverton North, Altona Meadows, Werribee, Wyndham Vale, Mount Cottrell, Eynesbury, Tarneit, Hoppers Crossing and Point Cook.

The station supplies approximately 100,000 Powercor customers, including a major customer connection supplied directly from its 66 kV bus.

A total of 145 MW capacity of embedded generation is installed on the Powercor distribution system connected to ATS West. It consists of:

[1] Data from the 2023 Transmission Connection Planning Report, pp55-61

- 20 MW of large-scale embedded generation; and
- 125 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

2.3 Powercor as the Transmission Connection Planner

ATS West connection assets exist solely to supply the Powercor's network and its connected customers. The 2023 Transmission Connection Planning Report (TCPR) describes the Victorian joint planning arrangements for transmission connection assets, and subsequently allocates responsibility for us to act as the Regulatory Investment Test proponent for this project.

2.4 Application of the Regulatory Investment Test – Transmission (RIT-T)

Section 1.2 of the TCPR documents where Victorian DNSPs and AEMO have agreed that joint planning projects involving transmission connection and distribution investment should be assessed by applying the RIT-T.

This project is not an actionable ISP project, hence Rule 5.16 applies to this project[2]. At the time of production of this report, the current version of the National Electricity Rules (NER) is V 227, commencing 27/03/2025.

Having a project value for a network solution in excess of $7million[3], this project meets the criteria of Rule 5.16.3 of the NER and as such is subject to a RIT-T.

In October 2024, a Project Specification Consultation Report was published and we sought submissions in accordance with Rules 5.16.4 (d), (e), (f) and (g).

No submissions were received.

This report forms the next step of the RIT-T process, being the Project Assessment Draft Report (PADR) required under Rule 5.16.4.

[2] The term Rule refers to the National Electricity Rules

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

3 Identified Need

ATS West is a summer peaking station and its maximum demand reached 201 MW (208 MVA) in 2022-23 summer.

If one of the 150 MVA 220/66 kV transformers at ATS West is taken offline during peak loading times and the N-1 station rating is exceeded, AusNet as the owner of the assets, has an automatic load shedding scheme[4] that will act swiftly to reduce the loads in blocks to within safe loading limits. Where possible, any load reductions that are in excess of the minimum amount required to limit load to the rated import capability of the station would be restored at zone substation feeder level in accordance with Powercor's operational procedures after the operation of the shedding scheme. Note that possible load transfers away to ATS/BLTS and DPTS terminal stations in the event of a transformer failure at ATS West peak load total 24 MVA in summer 2024.

In addition, the load at ATS West is increasing such that the full short term rating of the station will be exceeded in the near future.

3.1 Identified need

Key factors driving the need for a solution include emerging no prior outage ('N') hours at risk at ATS West, as well as significant levels of single outage (N-1) hours of energy at risk that currently exist.

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-T, as the investment is required to comply with the above NER obligations. We also note that the identified need qualifies as Reliability Corrective Action.

Timing is discussed in section 3.2 and the first critical date for an 'N' constraint is forecast to occur in 2033.

3.2 Quantification of identified need through load forecasting

ATS West is a summer peaking station and its maximum demand reached 201 MW (208MVA) in 2022-2023 summer.

Figure 2 shows the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings. Note that export ratings are nameplate ratings. The chart shows a reduction in the 2021 actual maximum demand due to planned transfers of approximately 30 MW from the heavily loaded LV and WBE zone substations (supplied by ATS West) to Deer Park Terminal Stations (DPTS).

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal rating for export, as advised by the asset owner. The effective export rating may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown

[4] The load shedding scheme is designed to protect connection transformers against transformer damage caused by overloads. Damaged transformers can take months to repair or replace, which can result in prolonged, long term risks to the reliability of customer supply.

above therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

Load growth at ATS West is expected to remain strong due to high population growth and increasing commercial and industrial customer connections. Forecasts include the large load connection on the secondary bus at ATS West.

The "N" import rating on the chart indicates the maximum load that can be supplied from ATS West with all transformers in service. The "N-1" import rating on the chart is the load that can be supplied from ATS West with one 150 MVA transformer out of service.

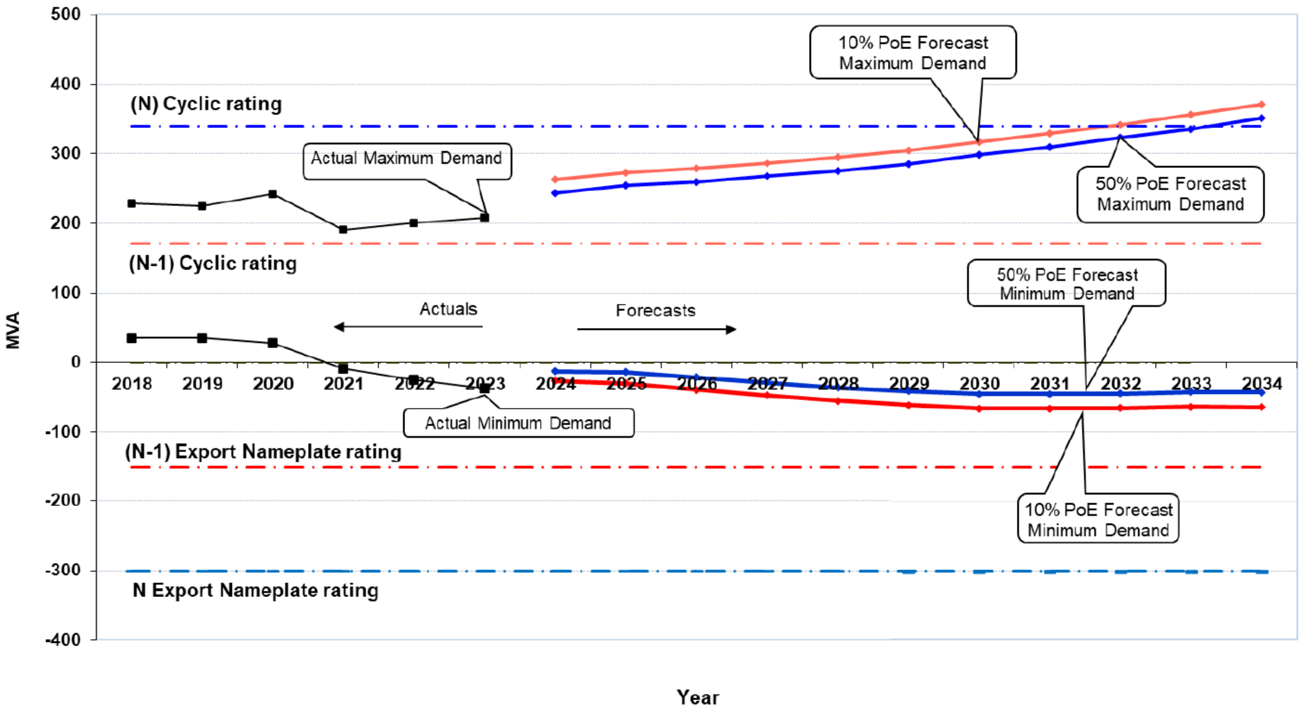

Figure 2 ATS West Maximum and Minimum Demand Forecasts

It is estimated that:

- For 7 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast (Probability of exceedance or POE50).
- The station load power factor at the time of maximum demand is 0.97

In relation to minimum demand, it is estimated that:

- For 1 hour per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99

3.3 Summary of impacts of forecasts

As discussed above in the peak demand forecast, electrical demand growth in the western growth corridor area is expected to continue in the short to medium term (and beyond).

Figure 2 shows that:

- there is insufficient import capacity to supply the forecast maximum demand at POE50 at ATS West if a forced outage of a transformer occurs,
- Load has currently exceeded ability to take a transformer bay out of service for operational and or maintenance reasons, and,
- forecast POE50 loads will exceed station capacity 2033.

There is an immediate operational risk for customers connected to ATS West that is increasing with continued load growth. Table 1 provides a summary of exceedances of the N and N-1 ratings exceedances (constraints) at ATS West. The probabilistic processes applied to energy at risk and value of customer reliability indicate an optimum time to invest where the cost of energy lost exceeds the cost of investment, in this case 2029. This latter time is shown in Table 1 as the optimum (and hence preferred) investment time.

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

Substation	Exceed N-1 rating	Exceed N rating	Optimum investment time
ATS West	**Now**	**2033**	**2029**

3.4 The counterfactual case

In the event that no action is taken, the energy at risk increases and the likelihood of ATS West's firm capacity being exceeded increases.

The cost of this scenario has been estimated using analysis of the magnitude, probability and impact of the loss of a transformer (N-1 system condition).

The line graph in Figure 3 shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the VCR[5] for this terminal station, which is $37,939 per MWh.

The bar chart in Figure 3 depicts the energy at risk with one transformer out of service for the 50th percentile maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating.

[5] AER Values of customer reliability, 2019. We note that the AER has released in late March 2024 a draft revision of the 2019 version, https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024

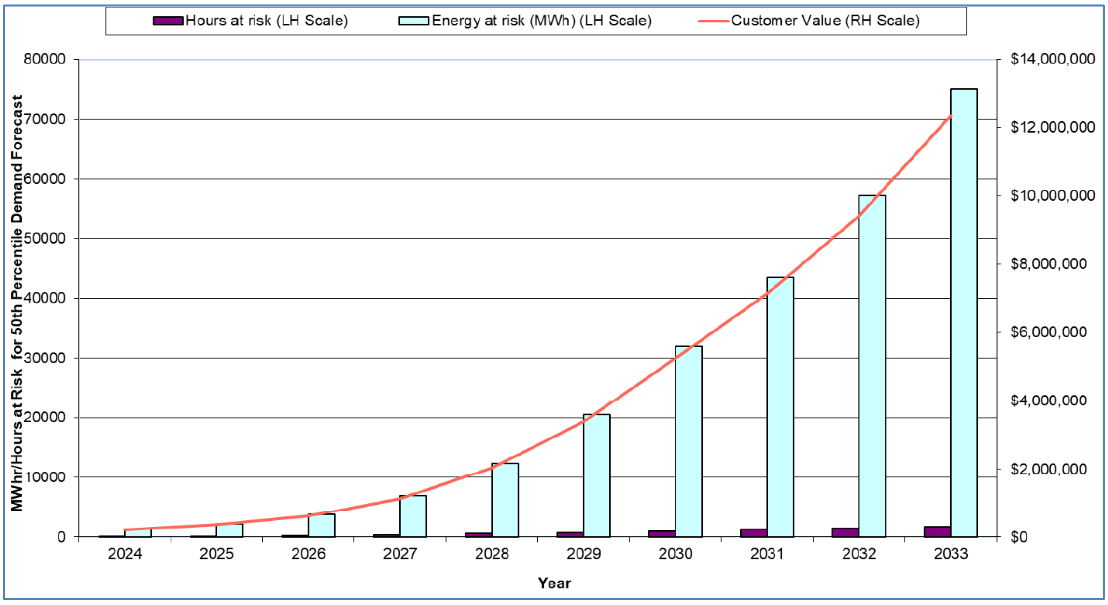

Figure 3 Annual energy and hours at risk and expected unserved energy at ATS West

Key statistics relating to energy at risk and expected unserved energy for 2029 under N-1 outage conditions are summarised in Table 2.

Table 2 Energy at risk and expected unserved energy in 2029

Scenario	MWh pa	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	20,528	$779 m
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition[8]	89	$3.37 m
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	26,695	$1,013 m
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition[8]	116	$4.39 m

Under the probabilistic planning approach[6], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%[7]) to determine the expected unserved energy cost in a year due to a major transformer outage[8]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

[6] Section 3 of the 2023 Transmission Connection Planning Report

[7] Section 5.4 of the 2023 Transmission Connection Planning Report

[8] The probability of a major outage of one transformer occurring is 1.0% per transformer per annum, refer to p57 of the 2023 Transmission Connection Planning Report

Table 2 shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[9]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2029 is $3.68 million.

Table 3 presents detailed data on system normal maximum and minimum demand forecasts and limitations over a 10 year period. Post 2033 is likely to have significant increases in energy at risk given the likely exceedance of the 50th percentile firm (N) capacity.

Notes for Table 3

Nameplate rating with all plant in service:	340 MVA via 2 transformers (summer)
Summer N-1 Station Import Rating:	170 MVA [See Note 1]
Winter N-1 Station Import Rating:	187 MVA
Summer N-1 Station Export Rating:	150 MVA [See Note 7]
Winter N-1 Station Export Rating:	150 MVA [See Note 7]

1. "N-1" means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Celsius.
2. "N-1 energy at risk" is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. "N-1 hours at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 months. The outage probability is derived from the base reliability data given in Section 5.4 of the 2023 TCPR.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2019 final determination, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.
8. Red font indicates demand exceeding N-1 rating
9. White font on red background indicates demand exceeding N rating
10. 2029 is the optimum investment time as discussed under Table 2.

[9] AEMO, Victorian Electricity Planning Approach, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

Table 3 System normal maximum and minimum demand forecasts and limitations (refer to preceding notes)

Import	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
50th percentile Summer Maximum Demand (MVA)	243.2	254.5	259.8	267.4	275.5	285.5	298.0	310.0	322.3	335.1
50th percentile Winter Maximum Demand (MVA)	202.1	216.2	228.5	241.8	256.9	272.6	289.4	303.2	317.3	333.5
10th percentile Summer Maximum Demand (MVA)	262.8	272.7	278.9	286.7	294.8	304.6	317.3	329.4	341.7	355.6
10th percentile Winter Maximum Demand (MVA)	208.9	223.2	235.6	248.9	264.2	280.4	297.5	311.6	325.5	342.1
N-1 energy at risk at 50th percentile demand (MWh)	1287	2211	3746	6885	12395	20528	31959	43503	57263	75086
N-1 hours at risk at 50th percentile demand (hours)	56.0	114.5	213.5	355.5	549.0	755.0	1003.5	1223.5	1450	1702.5
N-1 energy at risk at 10th percentile demand (MWh)	2301	3768	6110	10250	17031	26695	39815	52996	68027	88047
N-1 hours at risk at 10th percentile demand (hours)	91.0	183.5	303.0	467.5	672.0	892.0	1156.0	1395.0	1625.8	1909.8
Expected Unserved Energy at 50th percentile demand (MWh)	5.58	9.58	16.23	29.83	53.71	88.96	138.49	188.51	248.14	325.37
Expected Unserved Energy at 10th percentile demand (MWh)	9.97	16.33	26.48	44.42	73.8	115.68	172.53	229.65	295.61	395.17
Expected Unserved Energy value at 50th percentile demand	$0.21m	$0.36m	$0.62m	$1.13m	$2.04m	$3.37m	$5.25	$7.15m	$9.41m	$12.3m
Expected Unserved Energy value at 10th percentile demand	$0.38m	$0.62m	$1.00m	$1.69m	$2.8m	$4.39m	$6.55	$8.71m	$11.2m	$15.0m
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.26m	$0.44m	$0.73m	$1.30m	$2.27m	$3.68m	$5.64	$7.62m	$9.95m	$13.1m
Export	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
10th percentile minimum Demand (MVA)	26.6	30.1	39.0	47.4	55.2	61.1	66.3	66.0	65.7	63.7
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

4 Assumptions and Methodologies

4.1 Demand Forecasts, reasonable scenarios[10] and States of the world[11]

The 2023 Transmission Connection Planning Report (TCPR) has significant amounts of information that both address the *States of the world* and provide foundation for the scenarios and forecasts that are in turn used in this report.

In particular, Chapter 2 of the TCPR provides context with respect to the market including social and economic future scenarios, Chapter 3 describes its planning methodology and Chapter 4 documents Inputs and Assumptions for the TCPR. The information presented there underpins this report through determining load forecasts, energy at risk, expected unserved energy and value of customer reliability.

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 ± 10%. They are prepared by a combination of our internal estimators from standard component estimates, and, pricing from AusNet Services.
- Calculations for annual deferral values of projects are based on the discount rates from Table 31 of the AEMO Inputs, assumptions and scenarios report[12], with:
    - a lower bound rate of 4.69% based on Powercor's Weighted Average Cost of Capital (WACC)
    - a central rate of 7% and
    - an upper bound rate of 10.5%.

[10] Refer to clause 20 of the AER's publication *Regulatory investment test for transmission*, 2020

[11] Refer to clause 24 of the AER's publication *Regulatory investment test for transmission*, 2020

[12] https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation

5 Options to meet the identified needs

The network risks identified above must be addressed. To not do so will compromise our ability to both provide supply to existing customers and connect new customers to the system, as required by Chapter 5 of the NER.

5.1 Non-network options

Due to the magnitude of customers that are supplied from Altona West, Powercor has determined that there are no credible non-network options that could address the energy at risk to defer or replace the proposed works.

In summary, our reasons for this conclusion are:

- there is no opportunity to reduce the required assets and associated works
- partially reducing peak load through demand management

5.2 Credible Network Options

We have identified a credible network option for alleviation of constraints. The following option is technically feasible and potentially economical to mitigate the risk of supply interruption and/or to alleviate the emerging network import constraint:

Option (1) Install additional transformation capacity as well as extend and reconfigure 66 kV bus and feeders at ATS West.

This would result in the station being configured electrically so that three transformers are supplying the ATS West load (leaving existing arrangements unchanged at ATS for the one transformer to continue to provide capacity to the ATS/BLTS system). This option could be commissioned to meet constraint timing's optimum investment timing of 2029, requiring commencement in 2026 to allow for an estimated construction period of 30 months.

AusNet Services are the owner of the site and have provided two possible options to achieve this option. Both provide the same outcome but the second proposal would include a new 66kV reactor between the new transformer and the No 1 66kV bus. The difference between the two proposals from Ausnet Services approximates $100,000. Whilst making no commitment to which proposal would be accepted if the full RIT-T process confirms this option as the preferred option, we have elected to use the greater cost proposal for the purposes of this project assessment draft report.

Hence the estimated indicative capital cost for this option is $41M, covering the following scope of works:

1. Install new Transformer 150/150/1MVA, 220/66/11kV designated as B1 along with all the required civil and environmental works.

2. Establish new 220kV bay for B1 by installing new circuit breaker and associated plant within 220 rack bay 4.

3. Establish connection between Transformer and 220kV switchyard via 220kV underground cable.

4. Install a new 66kV Reactor between the new transformer and the Trans 66kV CB on No.1 66kV Bus.

5. Establish new bay 2 (trans side) on the No.1 66KV Bus and establish its connection with Transformer through 66KV overhead conductors.

6. Extend No.1 66KV bus for creation of 4 additional 66 bays.

7. Establish new 66KV bays 1, 2, 3 and 5 complete with circuit breakers, bus and feeder side underslung isolators on the No.1 66 Bus.

8. Install three Transformer neutral reactors on Transformer B1, B3 and B4

The RIT-T process requires an estimate of maintenance costs to be included for credible network options. The maturity of option (3) in this report is commensurate with the progress through the RIT-T process and an estimate of maintenance is provided to enable an understanding of the magnitudes of annual maintenance costs as we understand at this point.

For the purpose of the RIT-T process, we estimate that costs in the evaluation period used in this report are of the following magnitudes:

- $10,000 pa for the first 5 years, then,
- $20,000 to $30,000 pa for the following 10 years

It is not likely that this option will have material inter-network impact.

Market benefits for this option are assessed in Table 4.

Option (2) A new zone substation in the Rockbank East area supplied from DPTS

A new substation at Rockbank East would allow load to be transferred from Werribee and Tarneit substations, both of which are supplied by ATS West. The transferred load of 40 MW would relieve the approaching constraint on ATS West, and the Deer Park Terminal Station that would supply the new substation has capacity to accept the transferred load.

This will reduce rather than eliminate the load at risk at ATS West, but it allows for a deferral of investment at ATS West. It is this deferral combined with a lower initial capital cost that differentiates the option from the first.

The scope of work for this option includes:

1. Purchase of land
2. Design and construction of new substation
3. Extension of transmission network to supply the station
4. Modifications and upgrades to the distribution network to transfer loads to the new station.

From previous investigations we estimate that this option will have a capital investment approximating $30 million. Given that construction of the option would require 24 to 36 months, construction would commence in 2026 to meet constraint timing of 2029.

For the purpose of the RIT-T process, we estimate that costs in the evaluation period used in this report are of the following magnitudes:

- $30,000 pa for the first 5 years, then,
- $60,000 pa for the following 10 years

Eventually, it is likely that the identified need in this report will re-emerge due to organic load growth on ATS West, and for the purposes of analysing this option, it is assumed that the solution in option (1) would need to be implemented at a future date. The details associated with the investment at that time are the same as option (1).

The forecast growth for ATS West indicates that removal of 40MW would defer the constraint by 3 to 5 years, and for financial analyses, we use a base case of 5 years deferral.

It is not likely that this option will have material inter-network impact.

Market benefits for this option are assessed in Table 4.

5.3 Options considered but not progressed

We have identified a credible network option for alleviation of constraints that, while technically feasible, is not a better economic solution to mitigate the risk of supply interruption and/or to alleviate the emerging network import constraint:

Option (3) Upgrade existing transformers at ATS west

We explored upgrading the existing transformers as an option noting that the next commercially available size above the existing units is 225MVA. The physical size of these units is larger than the bay arrangements.

This option would require not only the purchase of two 225MVA transformers but would also require significant investment on civil and electrical infrastructure that exceeds the cost of Option (1). Our estimate of costs for upgrading one bay are close to that of option (1), and even if the second transformer upgrade can be deferred, this option will always be a higher cost than option (1) through all scenarios.

As such this option was not progressed.

5.4 Market Benefit Classes

Rule 5.16.4(b)(6)(iii) requires the RIT–T proponent must provide, for each credible option, information about the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material. Table 4 provides our assessment of market benefits for this PSCR stage of the RIT-T. Note that the responses are applicable to the one identified network option as well as considering the potential of any possible non-network solution responses.

We believe that the nature of the two credible options are such that the same market benefits apply to each case as discussed below.

Table 4 Market Benefits; assessment of materiality

Specified Class[13]		Material	Comments
a	Changes in fuel consumption arising through different patterns of generation dispatch;	Unlikely	The project is a connection asset that has a small impact on market generation capacity. Any generation related solution would likely be a peaking plant.
b	Changes in voluntary load curtailment	Possible	This is dependent on the ability to develop a non-network solution.
c	Changes in involuntary load shedding, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers	Yes	Refer to section 3.4.
d	Changes in costs for parties, other than the RIT–T proponent, due to differences in: the timing of new plant, capital costs, and operating and maintenance costs	Possible	This is dependent on what, if any, non-network solutions may be developed.
e	Differences in the timing of transmission investment	Possible	This is dependent on what, if any, non-network solutions may be developed. Some solutions may provide deferment of a network solution and economic analyses required
f	Changes in network losses	Unlikely	This is dependent on the solution location. Any generation or network solution near ATS West site would likely see an insignificant change in losses between options, and, downstream embedded generation solutions will see an increased capital requirement because of likely multiple sites that would overwhelm loss savings
g	Changes in ancillary services costs	Unlikely	The project is a connection asset that has a small impact on the NEM.

[13] Refer to Paragraph 11 of the AER Regulatory investment test for transmission, August 2020 and Rule 5.15A.2(b)(4)

Specified Class[13]		Material	Comments
h	Changes in Australia's greenhouse gas emissions	Unlikely	This project is a connection asset that has a small impact on Australia's greenhouse gas emissions.
h	Competition benefits, being net changes in market benefits arising from the impact of the credible option on participant bidding behaviour	Unlikely	The project is a connection asset that has a small impact on the NEM.
i	Any additional option value (meaning any option value that has not already been included in other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market	Unlikely	The project is a connection asset that has a small impact on the NEM.
j	The negative of any penalty paid or payable (meaning the penalty price multiplied by the shortfall) for not meeting any relevant government-imposed instruments (such as the renewable energy target), grossed-up if not tax deductible to its value if it were deductible	Unlikely	The project is a connection asset that has a small impact on the NEM.
k	Other benefits that the RIT–T proponent determines to be relevant and are agreed to by the AER in writing before the project specification consultation report is made available to other parties	No	No other market benefits identified.

Rule 5.16.4(k)(6) requires the *identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions).* This project is quite small in the context of the NEM's Victorian transmission network. We have not been able to identify market benefits in this area.

5.5 Market Benefit Value

Given the assessment of market classes in the above section, the quantification of market benefits is fundamentally the value of unserved energy avoided as a result of implementing either of the two feasible options. Section 3.4 discusses how the value of this class has a value of $29m for the purposes of Market Benefits used in the financial evaluation in this RIT-T.

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. Operations and maintenance costs for each option have also been included.

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.

6.1 Modelling results

The modelled financial results and subsequent preference ranking of the two credible network options are shown in Table 5, where the costs and timing are from section 5.2, and the market benefits from section 5.5. As this project's identified need meets the definition of a reliability corrective action, clause 5.15A.1 (c) of the NER allows a negative net economic benefit.

Table 5 Model results for Base Case; 7.00% discount rate

Option		Cost	Benefit	NPV	Ranking
(a)	Upgrade Altona West Terminal Station	$ 29.4m	$ 29m	$ 0m	1
(b)	New Rockbank East SS and deferral of ATS-WEST	$ 42.6m	$ 29m	$ -14m	2

Table 5 shows option (a) being both the least cost option and also a non-negative NPV result. This indicates that option (a) is the preferred option using the base case analysis.

6.2 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 sensitivity analysis. Given the common market benefit value, sensitivity analyses will be viewed purely from a cost perspective.

(i) Changing the discount rate in response to economic conditions.

Given that the options contain investments with different timing, it is appropriate to ensure that the results of differing discount rates will not alter the ranking of results from the base case.

Testing of this variable is carried out by using the upper and lower bounds of the discount rates as described in section 4.2, with results shown in Table 6.

Table 6 Scenario results for varying Discount Rate

Option	Discount rate:	3.00%	7.00%	10.5%	Ranking
(a)	Upgrade Altona West Terminal Station	$ 35.6m	$ 29.4m	$ 25.0m	1
(b)	New Rockbank East ZSS and deferral of ATS-WEST	$ 57.0m	$ 42.6m	$ 33.6m	2

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

(ii) Timing of the Upgrade of ATS West in option (b)

Returning the discount rate to the base case, the next variable to be modified is the load constraint timing for deferrable upgrade at ATS West in Option (b).

Note that in all cases the initial constraint timing of 2029 is used in both options, and it is only option (b) that will benefit from an increased deferral, presumably due to less load demand growth than the base case. This assumes that the identified need constraint is close enough that it is unlikely to alter, and, takes away the same relative shift between options that would otherwise simply maintain similar separation in economic modelling.

There is little benefit in analysing a lesser deferral of option (b)'s timing for the eventual upgrade of ATS West as the base case already provides a greater nett benefit that would only increase in that case.

Therefore the timing analyses use two scenarios of reduced load growth forecast that will further extend the timing for investment in ATS West:

- The first defers by an additional 3 years, a very simplistic approach to align with an anticipated reduction in load growth of 50%.
- The second uses a 10 year additional deferral from the base case. This is most likely not a realistic option but does provide results of deferral to the outer fringe of the forecasting period.

Table 7 Scenario results for increased deferment of load constraint timing in option (b)

Option	deferred by:	Base case	+3 years	+10 years	Ranking
(a)	Upgrade Altona West Terminal Station	$ 29.4m	$ 29.4m	$ 29.4m	1
(b)	New Rockbank East SS and deferral of ATS-WEST	$ 42.6m	$ 38.7m	$ 32.3m	2

As shown in Table 5, Option (b), Upgrade of MTC substation, retains its status of preferred option under these scenarios.

(iii)Altering cost inputs for construction costs.

Substation cost variances were altered by +/- 10%.

Table 8 Scenario results for variations in cost inputs

Option	Cost base variation:	-10%	base case	+10%	Ranking
(a)	Upgrade Altona West Terminal Station	$ 26.4m	$ 29.4m	$ 32.3m	1
(b)	New Rockbank East SS and deferral of ATS-WEST	$ 38.4m	$ 42.6m	$ 46.8m	2

The ranking of the options does not alter with credible cost variations, with Option (b) remaining as the preferred option.

6.3 Discussion on results of modelling

The market benefits are estimated to remain constant between the options. This is because they are valued mainly on VCR which remains constant irrespective of which option is applied.

Option (a) is the highest ranked option in all scenarios modelled in the sensitivity analyses. Given the similarity of the work involved with each option, the variables used apply equally to all options and as such the costs generally move with a similar percentage difference from the base case.

The main exception to this is the possibility to defer augmentation of ATS West in Option (b). However the difference in capital required between the options for the original action in 2029 is only $10M, and even with the discounted cost associated with significant deferral, modelling shows option (b) does not provide a better economic solution.

In considering the base case and all sensitivity analyses, Option (a) on average is a cost 28.9% lower than second ranked result, Option (b).

6.4 Preferred option

Clause 5.15A.1 (c) of the NER defines the principle that the preferred option:

"maximises the present value of net economic benefit"

The base case and all analyses modelled highlight that Option (a) is the lowest cost option while the market benefits of each option have been assessed to be the same.

Therefore, Option (a) is identified as the preferred option of the credible and technically feasible options.

7 Next steps

Powercor Australia will publish this Project Assessment Draft Report (PADR) in accordance with the requirements of the NER, inviting enquiries and submissions from interested parties.

A consultation period required under Rule 5.16.4(r) of 6 weeks following the publishing of a summary of this report by AEMO on its website will be provided. The actual closing date is listed in Section 9 of this report, and submissions can be made using details supplied in that section.

We note that Rule 5.16.4(z1)(1) allows an exemption from the PADR step of the RIT-T process if the capital cost is less than $46m[14]. As part of the PSCR process, we explained that, given the cost of the preferred option for this identified need approaching the magnitude of the exemption trigger, we believe that it is appropriate to not use the exemption allowed under Rule 5.16.4(z1).

On completion of the consultation period, we will assess any submissions before continuing the RIT-T process to the next stage of a Project Assessment Conclusion Report (PACR).

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

8 Satisfaction of RIT-T

The preferred option as summarised in Section 6.4 satisfies the Regulatory Investment Test for Transmission. This statement is made based on the detailed analysis set out in this report.

Table 9 Checklist of Regulatory Compliance

Rules clause	Requirement	Section of this report
5.16.4(k)	The project assessment draft report must include:	
5.16.4(k)(1)	A description of each credible option assessed	Section 5
5.16.4(k)(2)	a summary of, and commentary on, the submissions to the project specification consultation report;	
5.16.4(k)(3)	a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	Section 5
5.16.4(k)(4)	a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Section 5.4
5.16.4(k)(5)	reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Section 5.4
5.16.4(k)(6)	the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	Section 5.4
5.16.4(k)(7)	the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Section 6
5.16.4(k)(8)	the identification of the proposed preferred option;	Section 6.4
5.16.4(k)(9)	for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission; and	Section 5

9 Lodging a submission

Rules clause	Requirement	Section of this report
5.16.4(k)(10)	RIT reopening triggers applying to the RIT-T project where the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination)	N/A, project less than $100M

We invite written submissions for non-network and or SAPS solutions to address the identified need in this report from any interested parties. Our aim is to develop the distribution network, including transmission connection assets, in a manner that maximises net economic benefits to all those who produce, consume and transport electricity in the National Electricity Market. We welcome submissions that may assist in this regard.

All submissions should include sufficient technical and financial information to enable us to undertake comparative analysis of the proposed solutions against alternative options. The proposals should include, but are not limited to, the information listed in section 5.1 of this report.

Powercor will not be legally bound or otherwise obligated to any person who may receive this project specification consultation report or to any person who may submit a proposal. At no time will Powercor be liable for any costs incurred by a proponent in the assessment of this non-network options report, any site visits, obtainment of further information from us or the preparation by a proponent of a proposal to address the identified need specified in this non-network options report.

Submissions can be provided electronically to the email address provided below:

Attention: ATS West
rittenquiries@powercor.com.au

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

Attention: ATS West

Powercor Australia Limited

Locked Bag 14090 Melbourne Vic 8001.

Submissions may be published on our website. If you do not want your submission to be published, please state this at the time of lodgement.

All submissions are due on or before 17:00 on 29 July 2025.

Following our review of any submissions made, any option chosen to address the identified need will be set out in the draft project assessment report required by the RIT-D assessment process.

We intend to complete our review of submissions and the selection of the final project assessment report by 29 July 2025.

A. Glossary of terms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATS	Altona Terminal Station
ATS West	A portion of ATS dedicated as connection assets to the Powercor network
BLTS	Brooklyn Terminal Station
DAPR	Distribution Annual Planning Report
DNSPs	Distribution Network Service Providers
HV	High Voltage
ISP	Integrated System Plan
kV	kiloVolt (1000 Volts, a unit of electrical potential)
MVA	MegaVoltAmperes – unit of apparent power
MW	MegaWatts – unit of real power
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
NEM	National Electricity Market
NER	National Electricity Rules (Version 209, 4th April 2024)
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
PSCR	Project Specification Consultation Report (this report)
PV	Photo Voltaic (Solar panels)
RIT-T	Regulatory Investment Test for Transmission

Term	Definition
TCPR	2023 Transmission Connection Planning Report
VCR	Value of customer reliability