Emerging Load Constraint: Deer Park Terminal Station

Project Specification Consultation Report

June 2025

Contents

1 Overview

Deer Park Terminal Station (DPTS) is located west of Melbourne in the Melbourne West Growth Corridor.

Deer Park Terminal Station has two dedicated transformers and associated equipment as transmission connection assets to supply the local Powercor network.

The most recently recorded peak demand on DPTS was such that if one transformer was out of service for any reason, it would not have been possible to supply all the load at the time of peak demand. The ten-year load forecast, which includes some committed major customer connections, indicates that by the summer of 2030/31 the station load will exceed transformer short term loading capacity with both transformers in service at times of peak demand.

This report has identified one credible network option to mitigate the current and emerging constraints but acknowledges that there may be non-network solutions that may be developed as an option.

Implementation of a solution must occur before the deterministic constraint timing of 2030/31, however using probabilistic planning processes, the cost to customers through the value of lost energy will exceed the annualised cost of investment in 2027. Therefore, it may further the National Electricity Objective to invest in 2027 dependent on the cost and benefits of the preferred solution found through the RIT-T process.

Powercor Australia now seeks further 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. Submissions are due by **31 July 2025**.

Powercor will consider all submissions received in response to this project specification consultation report before preparing a Project Assessment Draft Report.

2 Background

2.1 Configuration of the local transmission network

Deer Park Terminal Station (DPTS) is located at the corner of Christies Road and Riding Boundary Road in Deer Park. It is connected in to one of the three 220kV circuits that connect Keilor Terminal Station (KTS) and Geelong Terminal Station (GTS). DPTS is equipped with two 225 MVA 220/66 kV transformers and has a nominal N-1 capacity of 225MVA.

The station supplies 109,058 Powercor customers in the areas of Sunshine, Truganina, Tarneit, Laverton North, Caroline Springs and Melton.

The approximate current supply area of DPTS is shown in Figure 1.

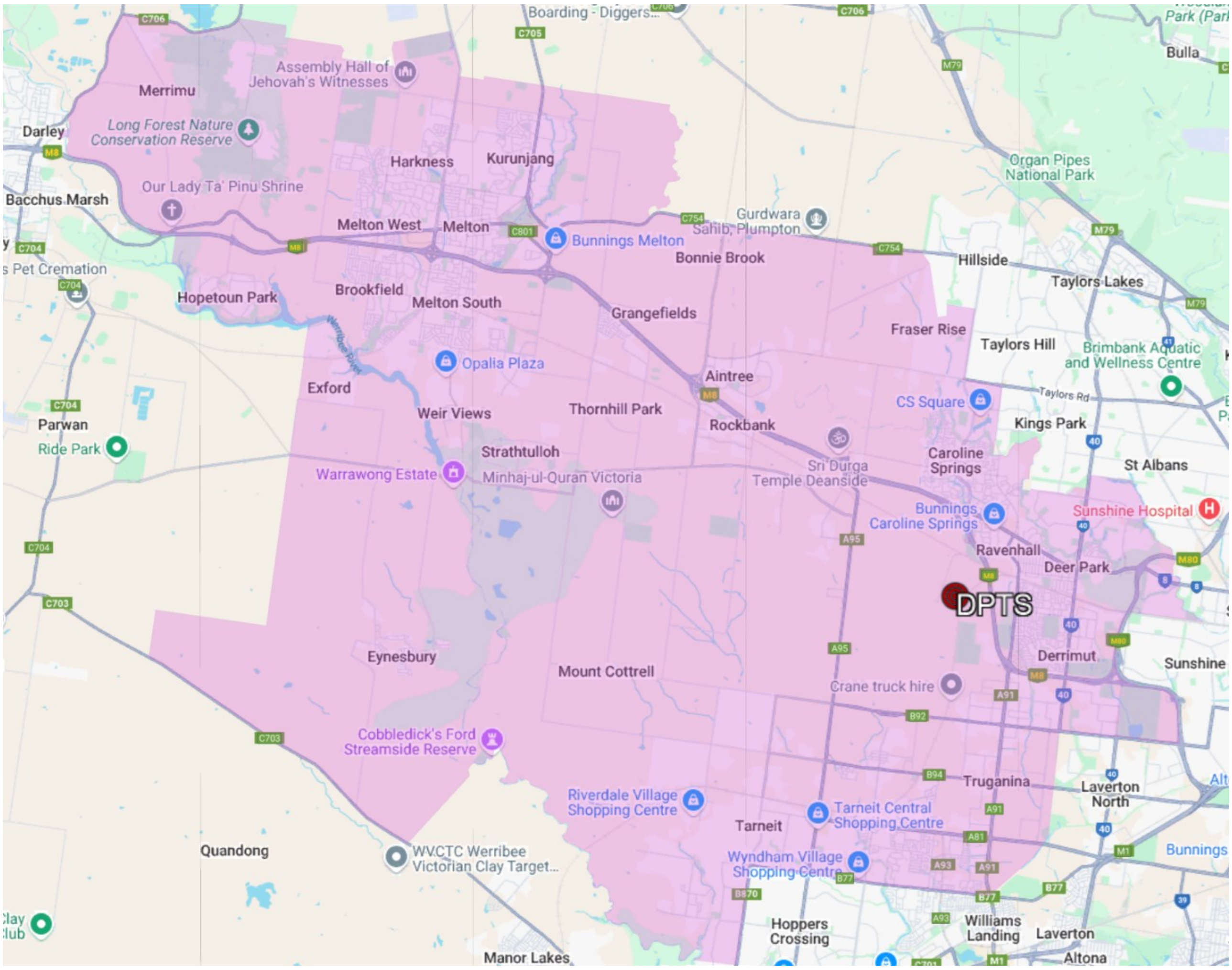

Figure 1: Geographic location of the supply area of Deer Park Terminal Station

2.2 Deer Park Terminal Station

A total of 176.8 MW of embedded generation is installed on the Powercor distribution system connected to DPTS. This consists of:

- 8.8 MW of large-scale embedded generation; and
- Around 168 MW of rooftop solar PV, including all the small-commercial and residential rooftop PV systems that are smaller than 1 MW.

2.3 Powercor Australia as Transmission Connection Planners

DPTS connection assets exist solely to supply the Powercor Australia's network and its connected customers. AEMO's Victorian Annual Planning Report (VAPR) 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 Transmission Connection Planning Report (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[1]. At the time of production of this report, the current version of the National Electricity Rules (NER) is V230.

Having a project value for a network solution in excess of $8 million[2], this project meets the criteria of Rule 5.16.3 of the NER and as such is subject to a RIT-T.

This report forms the Project Specification Consultation Report (PSCR) required under Rule 5.16.4.

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

[2] https://www.aer.gov.au/industry/registers/resources/reviews/2024-cost-thresholds-review-regulatory-investment-test

3 Identified Need

Deer Park Terminal Station is a summer peaking station with a firm (N-1) nameplate capacity of 225MVA and an N-1 cyclic rating of 280MVA. Its maximum demand reached 291.7MW (298.6 MVA) in summer 2023 / 2024.

3.1 Identified need

Continued growth in demand in the area served by DPTS, including the proposed connection of the new Mt Cottrell ZSS to DPTS as well as committed major loads is reducing the available capacity at DPTS at times of high demand. Currently the firm (N-1) capacity of DPTS has been exceeded and the energy at risk in the event of a transformer failure is forecast to become significant from 2027.

Under Chapter 5 of the National Electricity Rules (NER), we are required to connect customers and in doing so must maintain compliance with power system performance and quality of supply standards.

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.

The first critical date for an 'N' constraint is forecast to occur in the summer of 2030/2031. More detailed discussion of the timing of the supply constraints and the required timing of a solution to the identified need takes place in Section 5.6.

It should be noted for completeness that the load growth at DPTS is also forecast to result in a constraint on the 220kV transmission network supplying the station. The work to overcome this constraint is included in this RIT-T as it is required to meet the needs of customers supplied from DPTS.

3.2 Quantification of identified need through load forecasting

Figure 2 provides an overall view of the import and export capacity of DPTS and the actual and forecast maximum and minimum demand through to the end of the ten-year forecast period. The import capacity is based on the cyclic rating of the transformers while the export rating is based on the nameplate rating, as advised by the asset owner.

In this figure, "Import" refers to energy being supplied from the transmission network to customers supplied from the low voltage side of DPTS. "Export" refers to energy being supplied from generation embedded within the DPTS network to the transmission network.

Load growth at DPTS is expected to remain strong due to high population growth and increasing commercial and industrial customer connections. Forecast demand includes the large load connection on the secondary bus at DPTS.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

Under the 50% POE forecast the demand on DPTS will exceed 95% of the forecast maximum demand for eight hours per year while demand will be lower than 105% of the minimum demand for one hour per year.

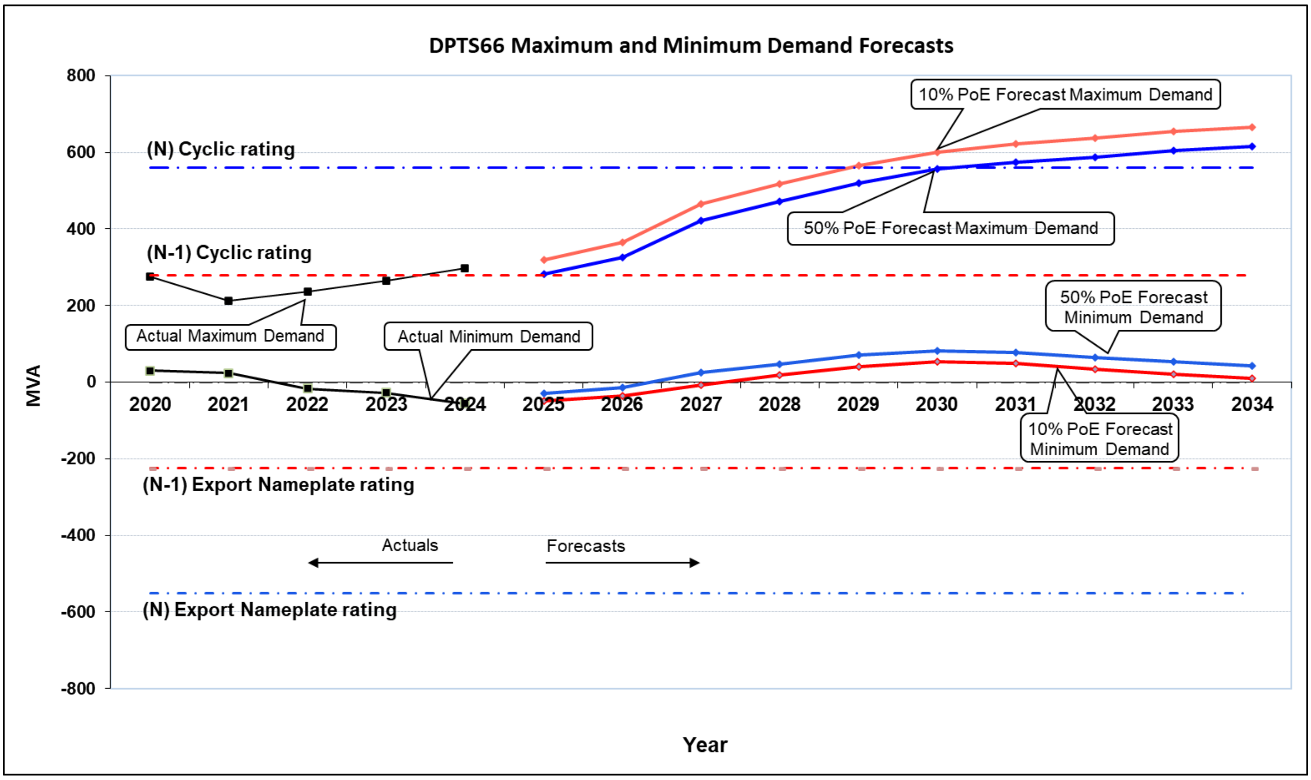

Figure 2: Deer Park TS Maximum and Minimum Historic and Forecast Load

Table 1: System normal maximum and minimum demand forecasts and limitations

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	282.4	326.8	420.6	472.1	520.2	555.7	573.8	588.2	604.3	615.5
50th percentile Winter Maximum Demand (MVA)	254.2	326.2	392.0	443.9	484.4	511.8	525.0	539.0	553.1	562.6
10th percentile Summer Maximum Demand (MVA)	319.3	364.8	464.4	516.9	565.8	601.4	621.2	636.6	654.4	666.7
10th percentile Winter Maximum Demand (MVA)	277.6	349.3	420.8	474.4	516.2	545.4	560.0	575.3	592.0	602.3
N-1 energy at risk at 50th percentile demand (MWh)	1.2	275.3	15236.0	52464.5	99977.5	143475.7	168286.6	194935.2	224493.5	245668.9
N-1 hours at risk at 50th percentile demand (hours)	0.5	27.0	555.0	1233.0	1848.5	2392.0	2695.8	2972.8	3261.3	3459.3
N-1 energy at risk at 10th percentile demand (MWh)	64.5	2153.0	33904.8	88226.9	153028.5	210924.8	244710.5	279448.3	320538.8	348096.4
N-1 hours at risk at 10th percentile demand (hours)	5.0	141.0	942.0	1716.0	2530.8	3150.8	3476.8	3779.8	4139.8	4375.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.01	1.19	66.02	227.35	433.24	621.73	735.95	864.18	1011.70	1121.57
Expected Unserved Energy at 10th percentile demand (MWh)	0.28	9.33	146.92	382.32	665.95	948.78	1130.05	1329.77	1594.06	1789.40
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.06M	$3.06M	$10.53M	$20.06M	$28.79M	$34.08M	$40.01M	$46.85M	$51.93M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.43M	$6.80M	$17.70M	$30.84M	$43.93M	$52.33M	$61.57M	$73.81M	$82.86M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.17M	$4.18M	$12.68M	$23.29M	$33.33M	$39.55M	$46.48M	$54.94M	$61.21M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	49.7	35.2	8.3	18.1	40.1	52.5	48.5	33.7	20.9	10.8
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

Notes

Nameplate rating with all plant in service:	450 MVA via 2 transformers
Summer N-1 Station Import Rating:	280 MVA [See Note 1]
Winter N-1 Station Import Rating:	300 MVA
Summer N-1 Station Export Rating:	225 MVA [See Note 7]
Winter N-1 Station Export Rating:	225 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

3.3 Expected Energy at Risk

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[3] for this terminal station, which is $46,304 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.

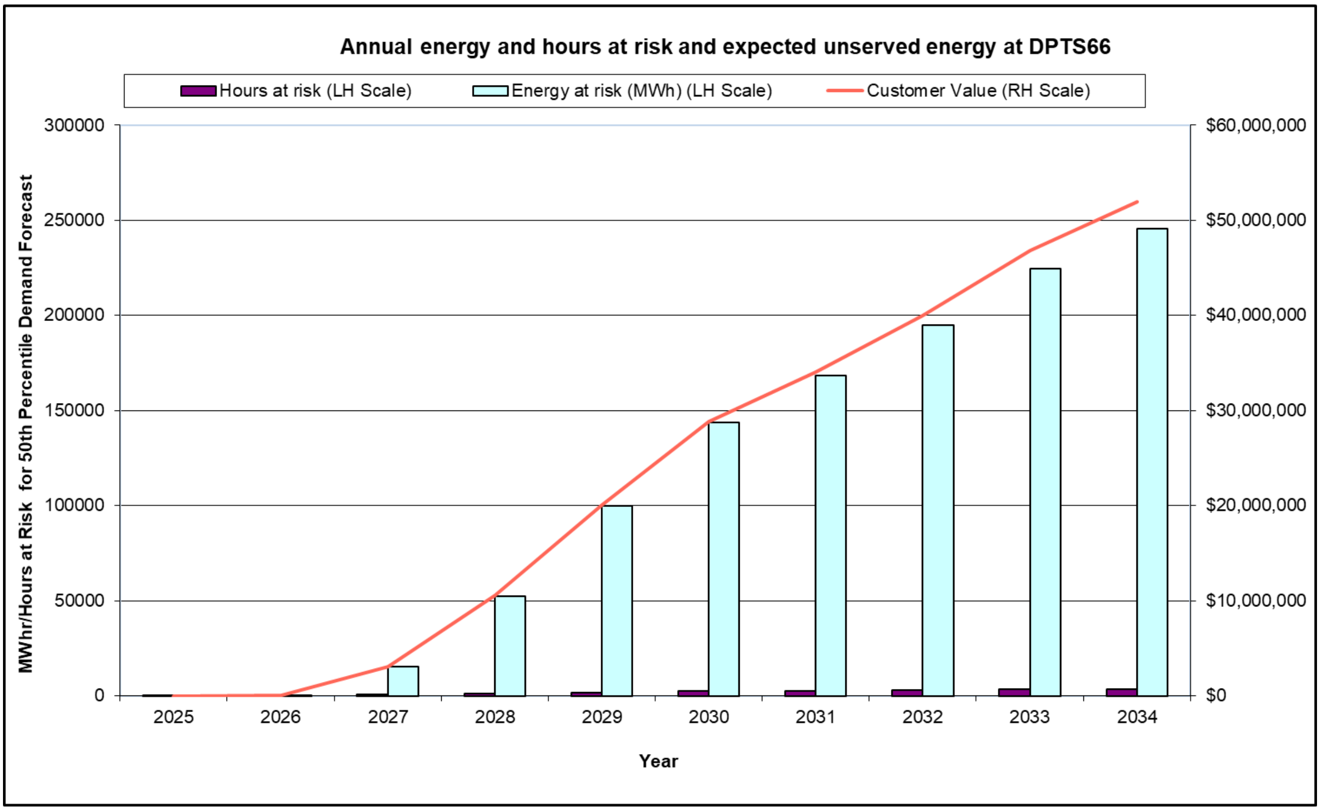

Figure 3: Deer Park TS Expected Unserved Energy

Under the probabilistic planning approach[4], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%[5]) to determine the expected unserved energy cost in a year due to a major transformer outage[6]. The VCR is used to value the expected unserved energy, which is compared to cost of investment required to remove the energy at risk. When the annual value of the

[3] AER 2023 Values of Customer Reliability Annual Adjustment

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

[5] Section 4.6 of the 2023 Transmission Connection Planning Report

[6] 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

expected unserved energy exceeds the annualised cost of the mitigating investment it is economical to invest to remove the risk. Section 5.6 discusses the preferred investment timing based on this analysis.

3.4 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 for the foreseeable future. Under this POE50 growth scenario:

- There is currently insufficient import capacity to supply the forecast maximum demand at DPTS if a forced outage of a transformer occurs;
- Similarly, there is insufficient import capacity to take a transformer bay out of service for operational and or maintenance reasons at times of peak demand, limiting opportunities for maintenance and operational flexibility;
- By 2031 peak demand will exceed the import capacity of the station, potentially resulting in the need to shed load.

4 Assumptions and Methodologies

4.1 Demand Forecasts

The demand forecasts represent our most recent view of the demand on our network under both POE50 (50% probability of exceedance) and POE10 (10% probability of exceedance) scenarios. These forecasts include new major committed customer loads and the impact of network configuration changes, including the connection of the recently established Mt Cottrell ZSS to the DPTS 66kV bus.

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 ± 20%. They are prepared using AEMO's Transmission Cost Database.
- Calculations for annual deferral values of projects are based on the discount rates from Table 31 of the AEMO Inputs, assumptions and scenarios report[7], 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%.

4.3 Transmission Connection Planning Report (TCPR)

The TCPR[8] is a joint report on transmission connection planning in Victoria, prepared by the five Victorian electricity distribution businesses, including Powercor, in accordance with the transmission connection planning requirements of Clause 19.3 of the Victorian Electricity Distribution Code of Practice and clause 5.13.2 of the National Electricity Rules.

The TCPR has significant amounts of information that underpin this report. Readers of this PSCR document should familiarise themselves with the TCPR. In particular, Chapter 3 describes the planning methodology of the TCPR and Chapter 4 documents Inputs and Assumptions for the TCPR. The information presented there underpins this report through determining energy at risk, expected unserved energy and value of customer reliability.

[7] https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en

[8] TRANSMISSION CONNECTION PLANNING REPORT

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

One purpose of this document is to provide information to proponents of non-network solutions (such as embedded generation, storage or demand-side management) regarding emerging network constraints, and thereby providing opportunity to have a broader input into this RIT-T project analysis.

Whilst not aware of any proposed solutions, we believe that it may be possible to develop non-network solutions that enable the deferral or avoidance of any network augmentation including without limitation:

- Demand reduction: There may be an opportunity to develop innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of potential demand reduction depends on the customer uptake and would be taken into consideration when determining the optimum timing of any network capacity augmentation.
- Embedded generation, connected to the DPTS 66 kV bus, may substitute for capacity augmentations. Alternatively, embedded generation at downstream location(s) such as our 66kV/22kV zone substation buses would also alleviate capacity constraints at DPTS.

Table 1 provides quantification of emerging demand constraints and energy at risk that any non-network solution must address.

We aim to develop our networks and the associated transmission connection assets in a manner that maximises net economic benefit. To this end, proponents of non-network solutions to the emerging network constraints identified in this report are encouraged to contact us if they are interested in obtaining more information to investigate non-network solution options.

To assist in the assessment of non-network solutions, proponents are invited to make a detailed submission to us. Submissions should be informed by discussions with us, and should include all of the following details about the proposal:

(a) proponent name and contact details;
(b) a detailed description of the proposal;
(c) electrical layout schematics;
(d) a firm nominated site;
(e) capacity in MW and MVAr to be provided and number of units to be installed (if applicable);
(f) fault level contribution, load flows, and stability studies (if applicable);
(g) a commissioning date with contingency specified;
(h) availability and reliability performance benchmarks;
(i) network interface requirements (as agreed with us);
(j) the economic life of the proposal;
(k) banker/financier commitment;
(l) proposed operational and contractual arrangements that the proponent would be prepared to enter into with us;
(m) any special conditions to be included in a contract with us; and

(n) evidence of a planning application having been lodged, where appropriate.

Any limits on the expected length of time that a non-network solution is expected to work to alleviate constraints should also be clearly detailed.

All proposals must satisfy the requirements of any applicable Codes and Regulations.

It is not likely that any non-network options will have material inter-network impact. An assessment of potential market benefits for non-network options are shown in Table 2.

5.2 Load Transfers

The load on DPTS can potentially be managed by permanently transferring load onto adjacent Terminal Stations. The two adjacent Terminal Stations where this may be a possibility are Altona Terminal Station West (ATS-WEST) and Keilor Terminal Station (KTS). One type of load transfer can be considered:

- Transfer of loads between zone substations using the 22kV distribution network.

To impact the demand on DPTS, transfers between zone substations using the distribution network require the load to be transferred to a zone substation supplied from another terminal station. The distribution network configuration is such that opportunities for this type of load transfer are minimal and are considered to have a non-material impact on the load at risk at DPTS. Temporary load transfers between zone substations may be used to manage reliability impacts in the event of a fault on the DPTS network.

At a terminal station level, the nearby Terminal Stations are:

1. **ATS-WEST**
   The load on this terminal station is already well above its N-1 capacity as discussed in a previous RIT-T[9] the transfers will only increase the load at risk. This is considered to be manageable in the short term, until a permanent solution can be implemented, as the risk of concurrent failures of transformers at ATS-WEST and DPTS is considered negligible.
2. **KTS**
   Potential transfers to KTS are minimal around 4 MVA and will make a non-material impact on the load at risk at DPTS. Powercor is also aware that Jemena has contracted some large customers from KTS and has engaged Powercor and AEMO to start a RIT-T at that Terminal Station. This will reduce the available transfer capacity to KTS.

Due to the low available spare capacity in the broader area and the rate of load growth, it is considered that load transfers only transfer load at risk between stations and do not alleviate it. Load transfers are not a viable solution to the identified network need.

[9] rit-t-pscr-atswest-v018.pdf

5.3 Credible Network Options

We have identified one credible network option to alleviate the network constraints and address the identified need. 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:

- Install an additional 225MVA 220/66kV transformer at DPTS, at an estimated capital cost of approximately $20 million. This would result in the station being configured so that three transformers are supplying the DPTS load. To avoid an overload on the existing 220kV lines supplying the DPTS, AEMO Victoria as the planner of the Victorian Transmission Network requires the two existing 220kV GTS-KTS lines to be cut into DPTS as part of this network option to allow an increase supply from the transmission network above the existing level. It is not likely that this option will have material inter-network impact. Market benefits for this option are assessed in Table 2.

5.4 Options considered but not progressed

No other options were identified that may address the identified need.

5.5 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 2 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.

Table 2 Market Benefits; assessment of materiality

Specified Class[10]		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	Demand exceeding the N-1 capacity of the station initially and the N capacity shortly thereafter means involuntary load shedding will be required at times of peak demand. This will be alleviated by the preferred solution.

[10] Refer to Paragraph 11 of the AER Regulatory Investment Test for Transmission, November 2024 and Rule 5.15A.2(b)(4)

Specified Class[10]		Material	Comments
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 DPTS 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.
h	Changes in Australia's greenhouse gas emissions	Unlikely	The project is a connection asset that has a minimal impact on greenhouse gas emissions.
i	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.
j	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.
k	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.
l	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.

5.6 Investment Timing

The first critical date for an 'N' constraint is forecast to occur in the summer of 2030/2031. Work to alleviate the constraint must have occurred by then to avoid involuntary load shedding at times of peak demand.

The estimated capital cost of the preferred investment option is $20 million. With a 45-year asset life and an allowance of 0.5% of the capital cost for annual operations and maintenance costs, this equates to an annualised cost of $1.58 million. An analysis of the Energy at Risk data presented in Table 1 shows that by 2027, the value of the energy not served exceeds the annualised cost of the investment required to mitigate the lack of capacity.

Table 3 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)[11]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2027 is $4.18 million. This is the first year when the value of the expected unserved energy exceeds the investment cost and indicates that 2027 is the optimum time to invest to mitigate this supply risk.

Table 3 Energy at risk and expected unserved energy in 2027

Scenario	MWh pa	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	15,236	$705 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition[8]	66	$3.1 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	33,904.8	$1570 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition[8]	146.9	$6.8 million

5.7 Draft Conclusion

Rule 5.15A.2(12) requires that the regulatory investment test for transmission must reflect that the credible option that maximises the present value of net economic benefit may, in some circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.

Only one credible network solution has been identified, to install a third 225MVA 220/66kV transformer at DPTS and cut in two additional 220kV transmission lines to the substation, at an estimated capital cost of approximately $20 million.

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

Therefore, in the event that no non-network solutions are identified that would be a more efficient solution, this option would become the preferred option.

We consider, in accordance with Rule 5.15A.2(b)(6), that this proposed preferred option will not have a material market benefit for the classes of market benefit specified in clause 5.15A.2(b)(4) except those classes specified in clauses 5.15A.2(b)(4)(ii) and (iii); ie changes in voluntary load curtailment and changes in involuntary load shedding, where the additional capacity provided by the preferred option will mean that neither of these measures will be necessary.

We note that the RIT-T process exists to further test this early finding.

6 Next steps

Powercor Australia will publish this PSCR in accordance with the requirements of the NER, inviting enquiries and submissions from interested parties.

A consultation period required under Rule 5.16.4(g) of 12 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 8 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 Project Assessment Draft Report step of the RIT-T process if the capital cost is less than $54m[12] and the preferred option will not have a material market benefit other than for the classes of market benefit related to voluntary load curtailment and involuntary load shedding. It is our expectation that these conditions will be met and, subject to refinement in the cost of the preferred network option and the content of submissions received on this project specification consultation report, there will be no requirement to publish a Project Assessment Draft Report.

Our Project Assessment Conclusions Report will address any issues that were raised in relation to the proposed preferred option during the consultation on this PSCR.

[12] 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER)

7 Satisfaction of RIT-T

Table 4 Checklist of Regulatory Compliance

Rules clause	Requirement	Section of this report
5.16.4(b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	
5.16.4(b)(1)	Description of the identified need for the investment	Section 3.1
5.16.4(b)(2)	The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-T proponent considers reliability corrective action is necessary)	Sections 3, 4
5.16.4(b)(3)	the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	Section 3.2
5.16.4(b)(4)	if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	N/A Section 2.4
5.16.4(b)(5)	a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options;	Section 5
5.16.4(b)(6)	for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) 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 benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Section 5.2

8 Lodging a submission

We invite written submissions for non-network and or generation 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 Project Specification Consultation Report.

Submissions can be provided electronically to the following email address:

Attention: Deer Park TS

rittenquiries@powercor.com.au

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

Attention: Deer Park TS

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 31 July 2025.

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

We intend to complete our review of submissions and the selection of the final project assessment report by 31 July 2025.

A. Glossary of terms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DPTS	Deer Park Terminal Station
HV	High Voltage
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
NER	National Electricity Rules
POE50	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
TCPR	2023 Transmission Connection Planning Report
VCR	Value of customer reliability