Altona-Brooklyn Terminal Station Capacity Constraint

RIT-T Stage 1: Project Specification Consultation Report (PSCR)

Executive summary

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and Powercor Australia Ltd. (**Powercor**), are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, servicing more than 384,000 and 945,000 customers respectively, within Melbourne's northern and western greater metropolitan area, and in western regional Victoria.

As expected by our customers and required by the various regulatory instruments that we operate under, JEN and Powercor aim to maintain service levels at the lowest possible cost for our customers. To achieve this, we assess options and develop plans that aim to maximise the present value of net economic benefit. Where relevant, this includes preparation of and consultation on regulatory investment tests.

The regulatory investment test for transmission (**RIT-T**) is an economic cost-benefit test and consultation process used to assess and rank potential investments capable of meeting an identified need in accordance with the requirements of clause 5.16 of the National Electricity Rules (**NER**)[1]. The purpose of a RIT-T is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**), as well as that arising from changes in Australia's greenhouse gas emissions.

The identified need for this RIT-T relates to forecast transmission connection capacity limitations at **Altona-Brooklyn Terminal Station (ATS-BLTS)**, a major source of supply to the JEN and Powercor electricity distribution networks. The limitations arise from forecast maximum demand growth, primarily driven by expected major customer data-centre connections within the Brooklyn supply area.

In Victoria, the DNSPs have responsibility (under their distribution licences) for planning and directing augmentation of the transmission connection assets that connect their distribution systems to the Victorian shared transmission system. This RIT-T has been initiated and jointly prepared by JEN (the lead proponent of this RIT-T) and Powercor electricity distribution networks, in accordance with the requirements of clause 5.16 of the NER and section 4.2 of the RIT-T Application Guidelines[2].

This project specification consultation report (**PSCR**) is the first stage of the **Altona-Brooklyn Terminal Station Capacity Constraint RIT-T** consultation process and contains information to enable prospective non-network and standalone power system (**SAPS**) providers to propose alternative options, including demand-side response or embedded generation and storage solutions.

Identified need

The identified need for this RIT-T is to deliver market benefits by maintaining electricity supply reliability and reducing expected unserved energy (**EUE**) for customers supplied from ATS-BLTS 66 kV [3].

ATS-BLTS 66 kV supplies approximately 63,346 customers across key areas such as Altona, Bacchus Marsh, Brooklyn, Laverton, Tottenham, Footscray, Newport, Spotswood, Williamstown and Yarraville.

Due to the expected increase in demand in the ATS-BLTS 66 kV supply area from the prospective major customer data-centre connections, the emerging level of EUE resulting from capacity limitations at ATS-BLTS 66 kV is forecast to grow if action is not taken, resulting in a deterioration of supply reliability for our customers.

[1] National Electricity Rules, version 218, Australian Energy Market Commission (AEMC), 2024.

[2] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.

[3] The 66 kV bus group at BLTS currently operates in parallel with the Altona Terminal Station (ATS) 66 kV bus group No.1 and No. 2 via ATS B2, being two terminal stations in close proximity, connected by strong sub-transmission ties. For the purposes of this RIT-T, this combined Altona-Brooklyn Terminal Station (ATS-BLTS) 66 kV bus group has been abbreviated to ATS-BLTS 66 kV as distinct from ATS West which operates as a completely separate terminal station at the ATS site. The ATS West RIT-T undertaken by Powercor has no bearing on this ATS-BLTS 66 kV RIT-T, except that ATS B2 will become ATS B1 following the ATS West RIT-T preferred option.

Addressing this identified need by reducing the EUE with a prudent level of investment in a network, non-network or SAPS solution, is expected to result in a positive net economic benefit. The need for this investment has been flagged in the 2024 Transmission Connection Planning Report (**TCPR**), published jointly by the Victorian DNSPs[4].

Potential credible options

The potential credible options considered in this PSCR to address the identified need include:

- **Option 1** – Do nothing (base case);
- **Option 2** – Non-network or SAPS solution;
- **Option 3** – Establish a new BLTS North 66 kV bus group; and
- **Option 4** – Upgrade of the existing ATS-BLTS 66 kV bus group.

Initial analysis by JEN and Powercor has identified that Option 4 is likely to be the preferred *network* option, as it provides the greatest net market benefit. This assessment will be confirmed through this RIT-T process.

The estimated capital cost of the most expensive credible option to address the identified need exceeds the trigger of $8 million[5] for undertaking a RIT-T (and the estimated capital cost of all other credible options also exceeds this threshold).

Submissions

JEN and Powercor invite written submissions and enquiries on the matters set out in this PSCR from interested stakeholders. All submissions and enquiries should be titled "**Altona-Brooklyn Terminal Station Capacity Constraint RIT-T**" and directed to both:

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The consultation on this PSCR is open for 12 weeks, consistent with the NER requirements[6]. Submissions are due on or before 22 December 2025.

Submissions will be published on the Australian Energy Market Operator (**AEMO**), JEN and Powercor websites. If you do not wish for your submission to be published, please clearly stipulate this at the time of lodging your submission.

Next steps

Following conclusion of the PSCR consultation period, JEN and Powercor will, having regard to any submissions received on the PSCR, prepare and publish a project assessment draft report (**PADR**) including:

- A description of each credible option assessed;

[4] Transmission Connection Planning Report, Victorian Distribution Network Service Providers, 2024.

[5] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER).

[6] NER, clause 5.16.4(g).

- A summary of, and commentary on, the submissions on the PSCR;
- A quantification of the costs and material market benefits for each credible option, including a detailed description of the methodologies used in quantifying costs and material market benefits;
- The results of the net present value analysis for each credible option and explanation of the results; and
- Identification of the proposed preferred option to meet the identified need.

Publication of that report will trigger the second stage of consultation on this RIT-T.

JEN and Powercor intend on publishing the PADR in the first quarter of 2026.

Table of contents

List of tables

List of figures

Glossary

Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Contingency condition (‘N-1’)	An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Distributor (DNSP)	A distribution network service provider.
Energy-at-risk	The energy at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Expected unserved energy (EUE)	Refers to an estimate of the probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for a cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 384,000 customers covering north-west greater Melbourne.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Network	Refers to the system of physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network’s capability to transfer electricity to customers.
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.

Probability of Exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Transmission (RIT-T)	An economic viability test that establishes consistent, clear and efficient planning processes for assessing and consulting on transmission network investments over a prescribed limit.
Stand Alone Power System (SAPS)	An embedded power system that operates disconnected (islanded) from the network.
System Normal condition ('N')	The condition where no network assets are under maintenance or forced outage, and the network is operating in a normal configuration.
Terminal Station	A substation facility that houses transmission connection assets, connecting the distribution network to the Victorian transmission system.
Transmission Connection Asset	Transmission assets within a terminal station that are under the planning responsibility of the distributors connected to those assets.
Value of Customer Reliability (VCR)	Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
POE10 (summer)	Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC, with the demand expected to be exceeded every ten years.
POE50 (summer)	Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC, with the demand expected to be exceeded every two years.
POE50 and POE10 (winter)	Refers to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC, with the demand expected to be exceeded every two years and every ten years respectively.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AL	Altona Zone Substation
ATS	Altona Terminal Station
BMH	Bacchus Marsh Zone Substation
BLTS	Brooklyn Terminal Station
CB	Circuit Breaker
DNSP	Distribution Network Service Provider (distributor)
EUE	Expected Unserved Energy
FW	Footscray West Zone Substation
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo-Volts
LVN	Laverton North Zone Substation
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System Normal Condition
N.O.	Normally Open
N-1	Single Contingency Condition
NER	National Electricity Rules
NPV	Net Present Value
NSA	Network Support Agreement
NSP	Network Service Provider
NT	Newport Zone Substation
O&M	Operations and Maintenance
PADR	Project Assessment Draft Report
POE	Probability of Exceedance
PSCR	Project Specification Consultation Report
PV	Photovoltaic Panels
RIT-T	Regulatory Investment Test for Transmission
SAPS	Stand Alone Power System
TCPR	Transmission Connection Planning Report
TH	Tottenham Zone Substation
VCR	Value of Customer Reliability
YVE	Yarraville Zone Substation

1. Introduction

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and Powercor Australia Ltd. (**Powercor**), are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, servicing more than 384,000 and 945,000 customers respectively, within Melbourne's northern and western greater metropolitan area, and in western regional Victoria.

The regulatory investment test for transmission (**RIT-T**) is an economic cost-benefit test and consultation process used to seek, assess and rank potential investments capable of meeting an identified need. The purpose of the RIT-T is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**), as well as that arising from changes in Australia's greenhouse gas emissions. The process follows the requirements in clauses 5.15A and 5.16 of the National Electricity Rules (**NER**)[7].

JEN and Powercor are undertaking this RIT-T to evaluate options to maintain reliability of supply within the Altona-Brooklyn Terminal Station (**ATS-BLTS**) supply area (the identified need). Options investigated in this RIT-T aim to mitigate the risk of growing expected unserved energy (**EUE**), resulting in a forecast deterioration of power supply reliability. The capital cost of credible options (including the proposed preferred option) to address this identified need within the ATS-BLTS supply area is above the RIT-T cost threshold of $8 million[8], and so has triggered the requirement for a RIT-T.

This project specification consultation report (**PSCR**) is the first stage of the **Altona-Brooklyn Terminal Station Capacity Constraint RIT-T** consultation process and has been jointly prepared by JEN (as the lead proponent) and Powercor in accordance with section 4.2 of the RIT-T Application Guidelines[9]. This PSCR contains information to enable prospective non-network and standalone power system (**SAPS**) providers to propose alternative credible options, including demand-side response or embedded generation and storage solutions. The RIT-T process is summarised in Figure 1-1, below.

The structure of this PSCR is as follows:

- **Chapter 2** describes the identified need that JEN and Powercor are seeking to address, which is in relation to the ATS-BLTS 66 kV capacity limitations;
- **Chapter 3** outlines the assumptions made in identifying the need;
- **Chapter 4** outlines the proposed assessment methodology for this RIT-T;
- **Chapter 5** outlines the technical characteristics of the identified need that a non-network or SAPS option would be required to deliver to address the identified need;
- **Chapter 6** describes the credible options that JEN and Powercor consider could potentially address the identified need; and
- **Chapter 7** invites registered participants, AEMO, interested stakeholders, non-network and SAPS providers, and persons on the JEN and Powercor industry engagement registers to make a formal written submission on this PSCR.

The need for investment has been flagged in the 2024 Transmission Connection Planning Report (**TCPR**)[10], published jointly by the Victorian DNSPs.

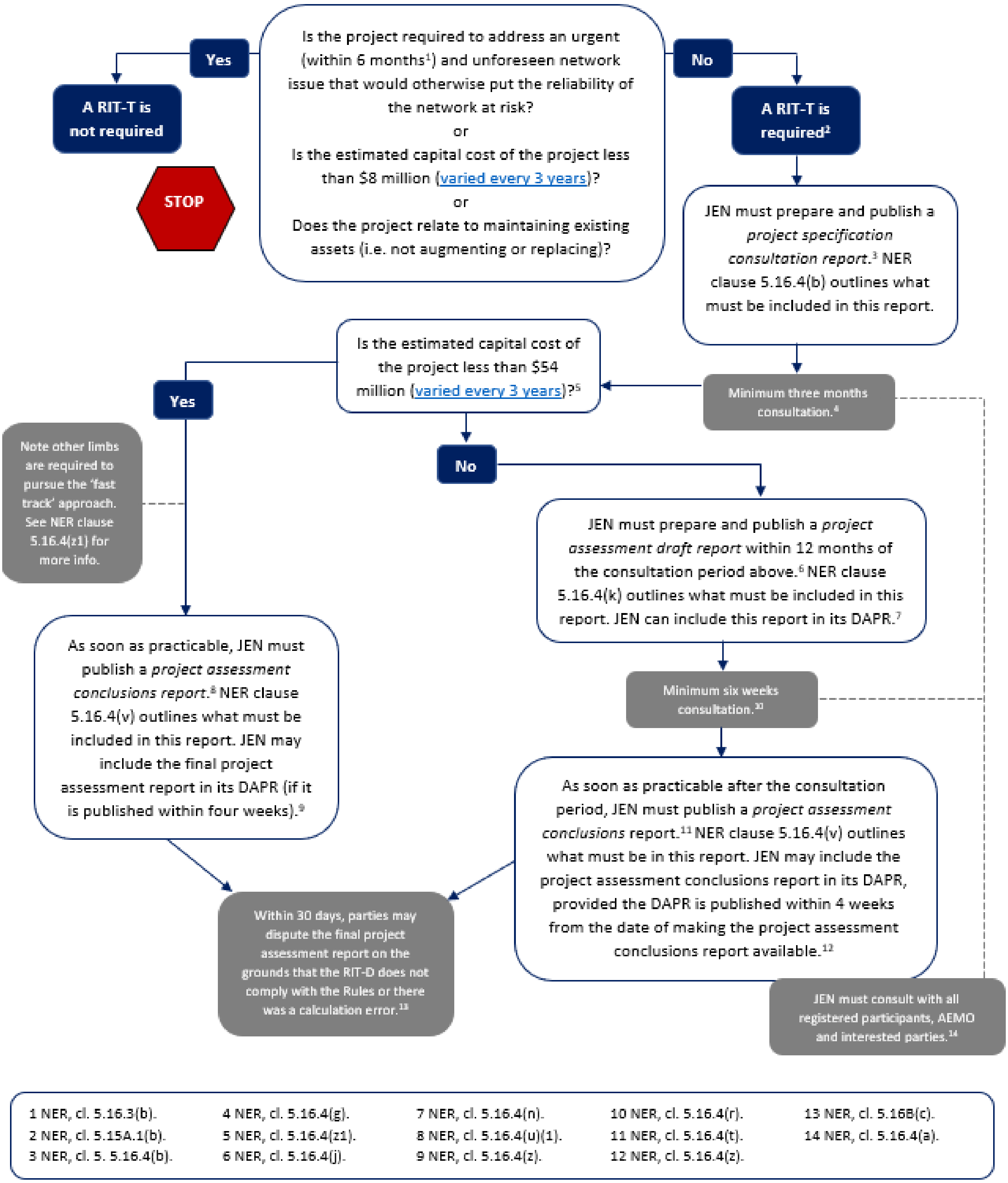
[7] National Electricity Rules, version 227, Australian Energy Market Commission (AEMC), 2025.

[8] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER).

[9] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.

[10] Transmission Connection Planning Report 2024, Victorian Distribution Network Service Providers, 2024.

Figure 1-1: RIT-T process flow chart



2. Description of the identified need

The NER and the AER's RIT-T Application Guidelines require that a PCSR must include a description of the identified need. This chapter addresses this requirement[11].

This chapter discusses the role of Altona-Brooklyn Terminal Station (**ATS-BLTS**) 66 kV[12] in providing electricity network services and the identified need associated with its current and forecast capacity limitations. Quantification of the risk and costs associated with the forecast increase in Expected Unserved Energy (**EUE**) in the base case (that is, the status-quo) is also presented.

2.1 Supply area

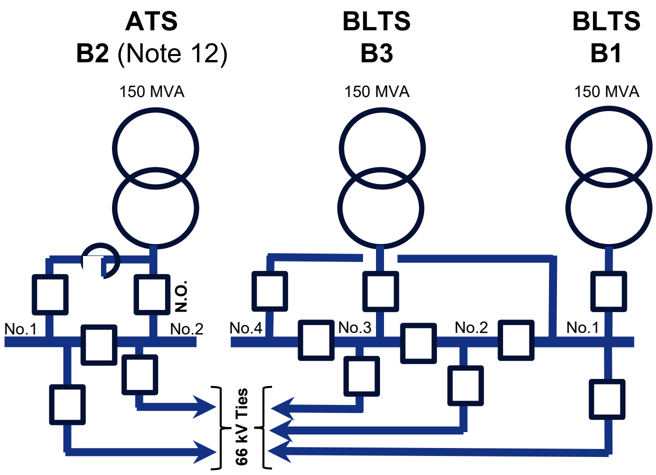
ATS-BLTS 66 kV is located in the inner-west of Greater Melbourne and supplies across key areas such as Altona, Bacchus Marsh, Brooklyn, Laverton, Tottenham, Footscray, Newport, Spotswood, Williamstown and Yarraville.

Electricity demand at ATS-BLTS 66 kV is soon expected to be one of the fastest growing in Victoria, with JEN receiving more than eight recent major customer data-centre connection requests mainly within the Footscray and Brooklyn industrial areas, located north of BLTS. If only one of these data-centre connections proceeds to full load, ATS-BLTS 66 kV will have exceeded its full capacity.

2.1.1 Electricity network servicing the supply area

The existing ATS-BLTS 66 kV bus group has three 150 MVA transformers (two located at BLTS being B1 and B3, and one remotely located at ATS being B2 currently[12]). Under system normal conditions, all three transformers are operated in parallel with B2 being connected through to B3 and B1 via multiple 66 kV tie lines (between ATS and BLTS) with each tie having zone substation load connected along the way. For an unplanned transformer outage of any one of the three transformers, the bus group reduces down to two transformers in parallel. This is illustrated in Figure 2-1.

Figure 2-1: ATS-BLTS 66 kV simplified single line diagram (existing)



The summer cyclic rating of ATS-BLTS 66 kV with all plant in service is 514 MVA and with one of its three 220/66 kV 150 MVA transformers out of service, reduces to 339 MVA (summer) and 386 MVA (winter).

[11] NER, clause 5.16.4(b)(1); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.

[12] The 66 kV bus group at BLTS currently operates in parallel with the Altona Terminal Station (ATS) 66 kV bus group No.1 and No. 2 via ATS B2, being two terminal stations in close proximity, connected by strong sub-transmission ties. For the purposes of this RIT-T, this combined Altona-Brooklyn Terminal Station (ATS-BLTS) 66 kV bus group has been abbreviated to ATS-BLTS 66 kV as distinct from ATS West which operates as a completely separate terminal station at the ATS site. The ATS West RIT-T undertaken by Powercor has no bearing on this ATS-BLTS 66 kV RIT-T, except that ATS B2 will become ATS B1 following the ATS West RIT-T preferred option.

2.1.2 Customer demand for electricity

More than 63,346 customers rely on ATS-BLTS 66 kV for their electricity supply. Commercial customers currently account for 54.6% of the total annual energy supplied by ATS-BLTS 66 kV followed by large business, residential and industrial customers as shown in Table 2.1.

Table 2-1: ATS-BLTS 66 kV net energy consumption – before connection of new data centres (GWh per annum, 2024)

Customer Type	ATS-BLTS 66kV	Proportion
Commercial	1,522	54.6%
Residential	341	12.2%
Industrial	325	11.6%
Agricultural	<1	0.0%
Large Business > 10 MW	598	21.5%
Total	**2,786**	**100%**

There has been an unprecedented number of data-centre and major load connection enquiries in the BLTS supply area over the last two years, with many enquiries needing feasibility assessments across multiple alternative locations within the service area. Some of the enquiries are now proceeding to formal connection applications and offers, with connection options frequently being tested by the applicants competitively across different distributors. If only one of these data-centre connections proceeds to full load, ATS-BLTS 66 kV will have exceeded its full capacity. To date, two data-centre connections for BLTS have proceeded through to construction.

Section 3.2.2 provides an overview of the maximum demand forecasts that underpin the identified need, and which reflect the expected connection of these new data centre loads.

Given the uncertainty that many of these uncommitted connections have in terms of commitment, timing and load uptake, we have not included their raw aggregated maximum demand within our underlying demand forecast. Instead, we have moderated their forecast maximum demands into aggregated block load forecasts. In doing so, we have applied several moderating factors to account for uncertainty - i.e., deferring the assumed connection date, slowing the uptake of the forecast data-centre load, and reducing the magnitude of the estimated connecting load, relative to the forecasts provided by the proponents.

JEN and Powercor intend to further test the uncertainty of future loads in the NPV assessment in the project assessment draft report (**PADR**) through the adoption of scenarios reflecting differing demand forecasts.

2.2 Identified need

There is forecast to be insufficient capacity to supply the forecast maximum demand at ATS-BLTS 66 kV with the existing transmission connection assets that are in place. This is likely to lead to a significant deterioration in supply reliability for customers supplied by this terminal station bus group under system normal and single contingency conditions, and inhibit the connection of new major customer data-centres within the supply area.

The identified need is to deliver market benefits from reduced expected unserved energy (**EUE**) by maintaining electricity supply reliability for customers supplied from ATS-BLTS 66 kV. Due to the expected increases in demand in the supply area from the prospective major customer data-centre connections, the level of EUE resulting from capacity limitations at ATS-BLTS 66 kV is forecast to grow as demand increases, deteriorating supply reliability for our customers if action is not taken.

Addressing this identified need by reducing the EUE with a prudent level of investment in a network, non-network or standalone power system (**SAPS**) solution, is expected to result in a positive net economic benefit.

There are two drivers of EUE at BLTS - a lack of “N” capacity (with all plant in service), and a lack of “N-1” capacity (with one transformer out of service). We note that BLTS has load transfer capability available at the distribution feeder level. This capability allows JEN and Powercor to manage risk in the short-term, by transferring load away from BLTS to surrounding terminal stations using spare capacity through each distribution network, to reduce the level of EUE.

Table 2-2 summarises the forecast capacity limitations at ATS-BLTS 66 kV, taking into account the moderated major customer data-centre connections load forecast on the overall demand at ATS-BLTS 66 kV.

Table 2-2: Forecast capacity limitations at ATS-BLTS 66 kV

ATS-BLTS 66 kV	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load at risk above ‘N’ (MVA)										
Summer POE10	0	0	0	0	0	0	11	31	51	70
Winter POE10	0	0	0	0	0	0	0	0	0	0
Summer POE50	0	0	0	0	0	0	0	4	24	43
Winter POE50	0	0	0	0	0	0	0	0	0	0
Time at risk above ‘N’ (h pa)										
Summer POE10	0	0	0	0	0	0	1	6	11	26
Winter POE10	0	0	0	0	0	0	0	0	0	0
Summer POE50	0	0	0	0	0	0	0	0	4	8
Winter POE50	0	0	0	0	0	0	0	0	0	0
Load at risk above ‘N-1’ (MVA)										
Summer POE10	0	16	70	126	142	161	180	200	220	239
Winter POE10	0	0	24	69	82	98	115	132	150	165
Summer POE50	0	0	43	99	117	135	153	173	193	212
Winter POE50	0	0	7	53	66	81	98	115	132	147
Time at risk above ‘N-1’ (h pa)										
Summer POE10	0	4	82	640	892	1239	1590	1938	2263	2532
Winter POE10	0	0	11	158	263	455	740	1024	1286	1505
Summer POE50	0	0	21	339	565	882	1230	1638	2018	2348
Winter POE50	0	0	3	80	141	262	459	758	1035	1270
Weighted EUE[13]										
‘N’ EUE (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	1.6	22.3	91.8	265.2
‘N-1’ EUE (MWh)	0.0	0.0	4.2	66.7	124.6	222	368	583	856	1,154
Total EUE[14] (MWh)	**0.0**	**0.0**	**4.2**	**66.7**	**124.6**	**222**	**370**	**606**	**948**	**1,419**
Value of EUE ($m[15])	**0.00**	**0.00**	**0.16**	**2.5**	**4.6**	**8.3**	**13.8**	**22.6**	**35.4**	**52.9**

13 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE, also considering the risk reduction provided by the available load transfer capabilities and the likelihood of the operating conditions. This weighting is consistently used by the Victorian DNSPs in its TCPR.

14 The total EUE is the summation of the EUE contribution during ‘N-1’ single contingency conditions (considering asset unavailability), and the EUE contribution during ‘N’ system normal conditions, considering the demand profile and seasonal ratings throughout the year.

15 Real 2025.

The value of EUE is derived by multiplying the level of EUE (in MWh) by an estimate of the Value of Customer Reliability (**VCR**). We have adopted the AER's estimate of VCR published in December 2024 as discussed further in section 4.1.1.

The EUE is estimated to have a value to consumers of around $2.5 million (real, 2025) by 2028, rising rapidly thereafter as the demand increases to $52.9 million by 2034.

The key elements of the "Do Nothing" supply reliability risk under the base case are shown in Figure 2-2 at ATS-BLTS 66 kV, considering the impacts of available transfer capacity.

Figure 2-2: ATS-BLTS 66 kV EUE risk costs (including impact of load transfer capability)

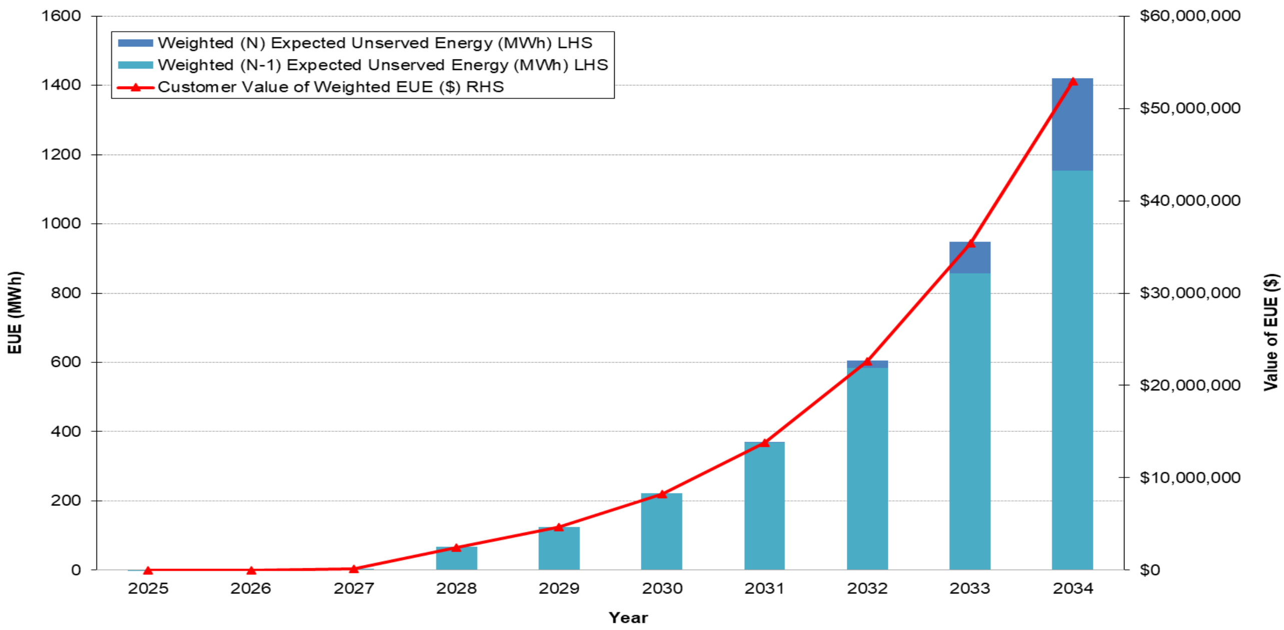


Table 2-3 summarises the forecast EUE at ATS-BLTS 66 kV and Table 2-4 summarises the value of the EUE (as per the totals from Table 2-2).

Table 2-3: Forecast EUE at ATS-BLTS 66 kV (Do Nothing)

BLTS EUE (MWh pa)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
POE50 (N)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	34.6	146.3
POE50 (N-1)	0.0	0.0	1.8	46.4	95.2	179.5	309.8	508.7	768.6	1,056
POE10 (N)	0.0	0.0	0.0	0.0	0.0	0.0	5.3	72.5	225.4	542.8
POE10 (N-1)	0.0	0.2	9.6	114.3	193.2	320.2	504.5	757.5	1,062	1,382
Total (Weighted[16])	**0.0**	**0.0**	**4.2**	**66.7**	**124.6**	**222**	**370**	**606**	**948**	**1,419**

Table 2-4: Forecast weighted value of EUE at ATS-BLTS 66 kV (Do Nothing)

BLTS EUE ($m, real 2025)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Weighted value of EUE	0.00	0.00	0.16	2.5	4.6	8.3	13.8	22.6	35.4	52.9

16 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE. This weighting is consistently used by the Victorian DNSPs in its TCPR.

3. Assumptions used in identifying the identified need

The NER and the AER's RIT-T Application Guidelines require that a PCSR must include the assumptions used in identifying the identified need[17]. This chapter details the assumptions used in identifying the identified need.

First, we set out the probabilistic planning approach applied by JEN and Powercor in planning the network, in the context of our overall approach to the net present value (**NPV**) analysis under the RIT-T. The following chapter then provides further detail on key assumptions that JEN and Powercor currently expect to adopt for the next stage of the RIT-T.

3.1 Overview of approach to the NPV analysis

Consistent with the RIT-T NER requirements[18], cost benefit analysis guidelines[19] and RIT-T application guidelines[20], JEN and Powercor will undertake a cost-benefit analysis to evaluate and rank the net economic benefits of credible options. All options considered will be assessed against a status-quo base case where no proactive capital investment to reduce the increasing baseline risks is made. The optimal timing of an investment option is the year when the annual benefits from implementing the option become greater than the annualised investment costs. The proposed assessment method for this RIT-T is set out in more detail in chapter 4.

In planning the network, JEN and Powercor apply a probabilistic planning approach that balances reliability of supply risk with the cost of potential risk mitigation options to identify the credible option that maximises the present value of net economic benefit (the preferred option) to all those who produce, consume and transport electricity in the NEM.

The probabilistic planning approach estimates the service level risk of identified network limitations by combining:

- the impact (consequence) of network limitations under various conditions; and
- the likelihood of those limits being reached, considering the combined probabilities of relevant demand, generation and network availability forecasts eventuating, and the available load transfer capability.

Service level reliability risk is then estimated in monetary terms as the product of:

- expected unserved energy (EUE) driven by the identified capacity limitations, in MWh per annum; and
- the locational value of customer reliability (**VCR**), in $/MWh, as set by the AER.

Having identified the service level reliability risk, JEN and Powercor will then take into account the potential costs of credible options, and the reduction in reliability risk that each option provides, to identify whether the investment will result in a positive net market benefit. This leads into the analysis that we will undertake as part of the PADR, where the credible option that maximises the present value of net economic benefit is identified by:

- quantifying and combining the avoided service level reliability risk of each credible option and that option's implementation and ongoing costs for each year; and
- identifying the credible option with the highest present value of total avoided service level reliability risk less the implementation and ongoing operating the maintenance costs.

The optimal timing of this preferred option is then identified by:

- calculating the preferred option's annualised implementation and ongoing costs; and

[17] NER, clause 5.16.4(b)(2); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.

[18] Regulatory investment test for transmission, Australian Energy Regulator, 21 November 2024.

[19] Cost Benefit Analysis guideline, Australian Energy Regulator, 21 November 2024.

[20] RIT-T application guideline, Australian Energy Regulator, 21 November 2024.

- selecting the year when the annual value of the avoided service level risk exceeds this annualised cost.

Application of the probabilistic planning approach often leads to the deferral of action that would otherwise proceed under a deterministic planning standard. Under a probabilistic network planning approach, conditions often exist where some of the load cannot be supplied under rare (but credible) conditions, such as at maximum demand or with a single network element out of service.

3.2 Input assumptions

The key assumptions used in identifying the need for this RIT-T apply to the:

- network asset ratings;
- forecast maximum demand;
- load transfer capability;
- annual load profile; and
- network asset reliability (failure rates, repair times).

3.2.1 Network asset ratings

The capability of the transmission connection assets at ATS-BLTS 66 kV is limited by the thermal rating of its three 220/66 kV 150 MVA transformers. Table 3-1 provides a summary of the capability of ATS-BLTS 66 kV for “N” and “N-1” conditions during summer and winter (maximum demand) seasons.

Table 3-1: ATS-BLTS 66 kV thermal capacity cyclic ratings (MVA)

Rating	Existing
	ATS-BLTS 66 kV
Summer (N)	508
Summer (N-1)	339
Winter (N)	579
Winter (N-1)	386

JEN and Powercor typically operate their networks using an N-1 probabilistic planning methodology which requires the maximum demand to exceed the N-1 rating (after load transfers, thereby resulting in EUE under single contingencies) before an augmentation can be considered.

3.2.2 Forecast maximum demand

The forecast maximum demand (**MD**) at BLTS is specified according to its 10 per cent probability of exceedance (**POE10**) and its 50 per cent probability of exceedance (**POE50**) during the summer and winter period[21], taking into consideration the moderated major customer data-centre load forecasts.

Table 3-2 provides a summary of the forecast maximum demand for ATS-BLTS 66 kV during summer and winter (maximum demand) periods. Values in red indicate that the N-1 rating is exceeded. Values in **bold underlined red** indicate that N rating is exceeded.

[21] Victorian electricity demand is sensitive to ambient temperature. Maximum demand forecasts are therefore based on expected demand during extreme temperature that could occur once every ten years (POE10) and during average conditions that could occur every second year (POE50).

Table 3-2: Forecast maximum demand at ATS-BLTS 66 kV (MVA)

ATS-BLTS 66 kV MD	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Summer POE10	319	363	413	465	481	500	**519**	**539**	**559**	**578**
Winter POE10	310	362	414	455	468	484	501	518	536	551
Summer POE50	293	337	386	438	456	474	492	**512**	**532**	**551**
Winter POE50	295	347	397	439	452	467	484	501	518	533

ATS-BLTS 66 kV is expected to exceed its N rating by 2031 for a POE10 and 2032 for a POE50 summer maximum demand. BLTS is expected to exceeding its N-1 rating for a POE10 summer maximum demand in 2026 and is expected to exceed its N-1 rating by 2027 for a POE50 summer maximum demand, and by 2027 for a POE10 and POE50 winter maximum demand.

Figure 3-1 shows the POE10 and the POE50 forecasts of maximum demand for ATS-BLTS 66 kV during summer periods relative to its capacity.

Figure 3-1: Summer period maximum demand forecasts for ATS-BLTS 66 kV

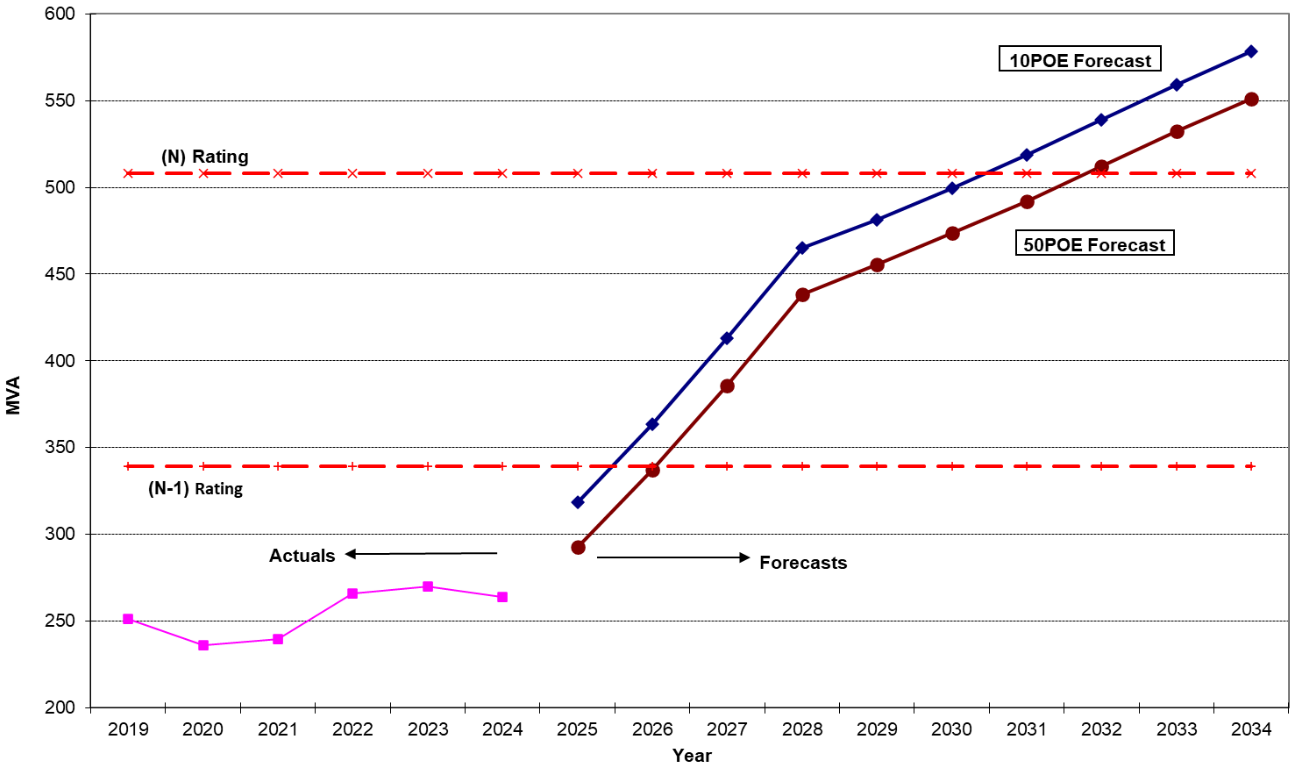
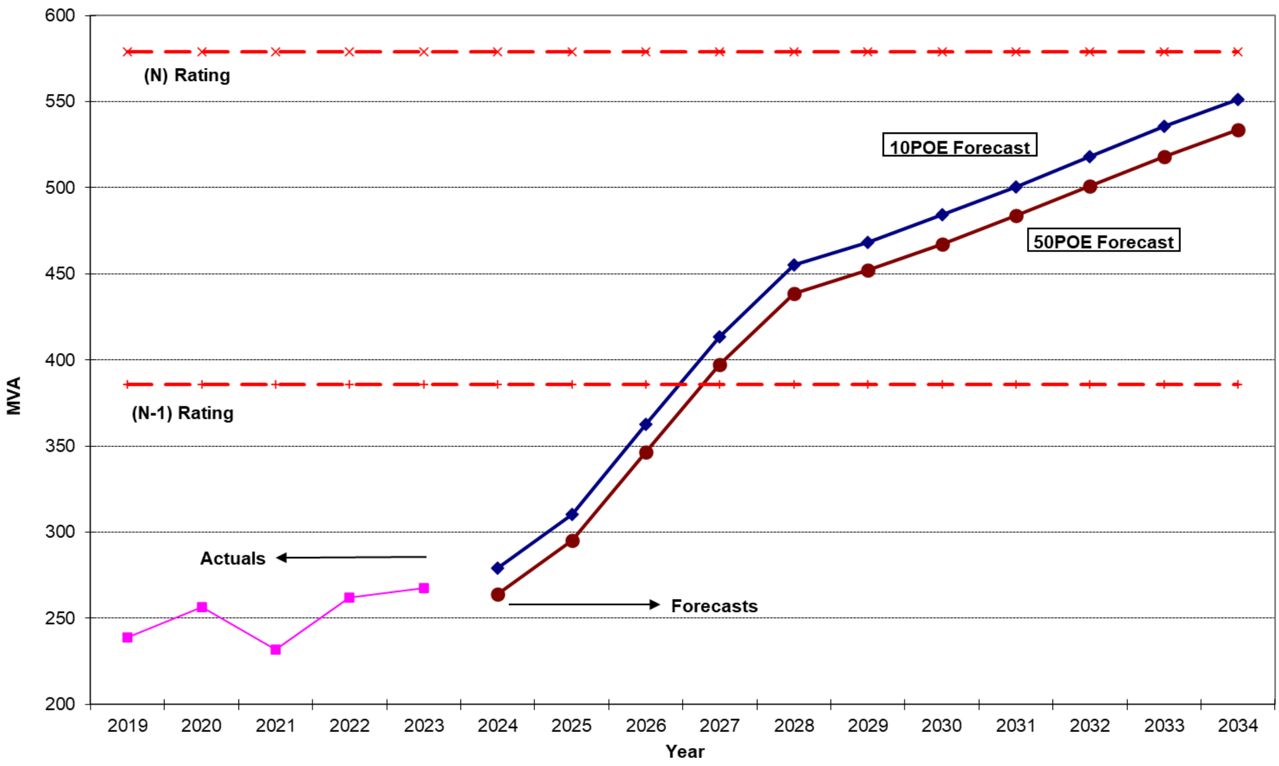


Figure 3-2 shows the POE10 and the POE50 forecasts maximum demand for ATS-BLTS 66 kV during winter periods relative to its capacity.

Figure 3-2: Winter period maximum demand forecasts for ATS-BLTS 66 kV



The maximum demand growth at ATS-BLTS 66 kV is predominately due to the growth in major customer data-centre demand within the supply area.

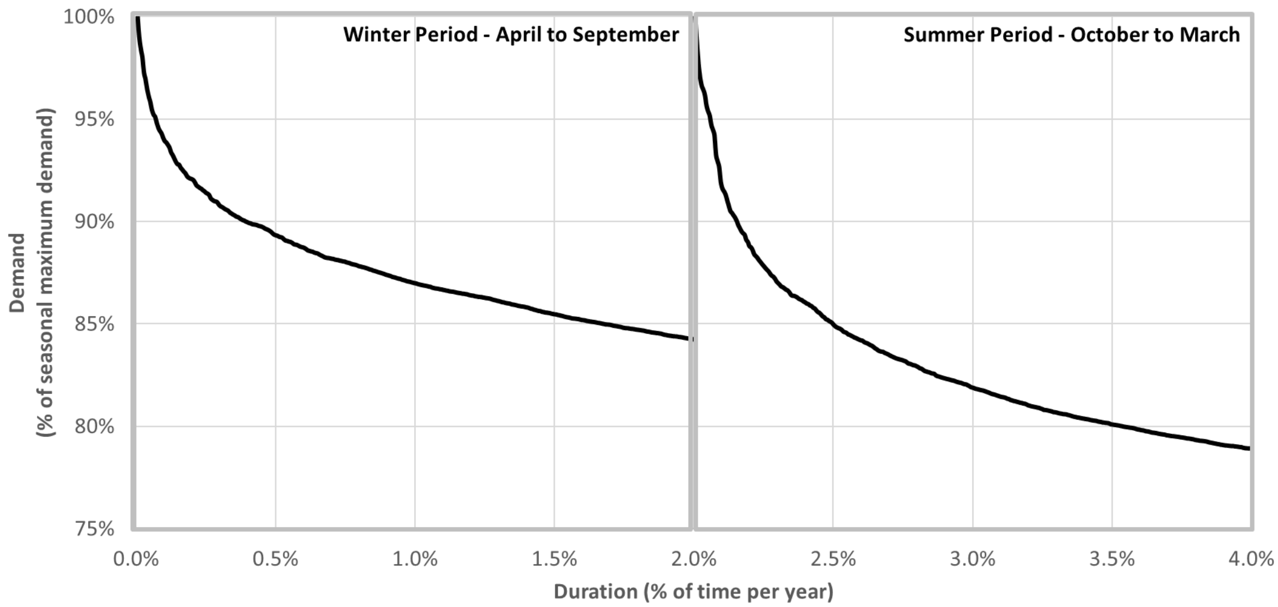
3.2.3 Load transfer capability

There is the capacity to transfer 8.0 MVA (Powercor) and 5.0 MVA (JEN) of load at BLTS to other terminal stations (post-contingent) via the distribution feeder network at peak demand in 2025. This transfer capacity is expected to reduce by 4.5 MVA per annum over the 10-year planning horizon due to growth in the area.

3.2.4 Annual load profile

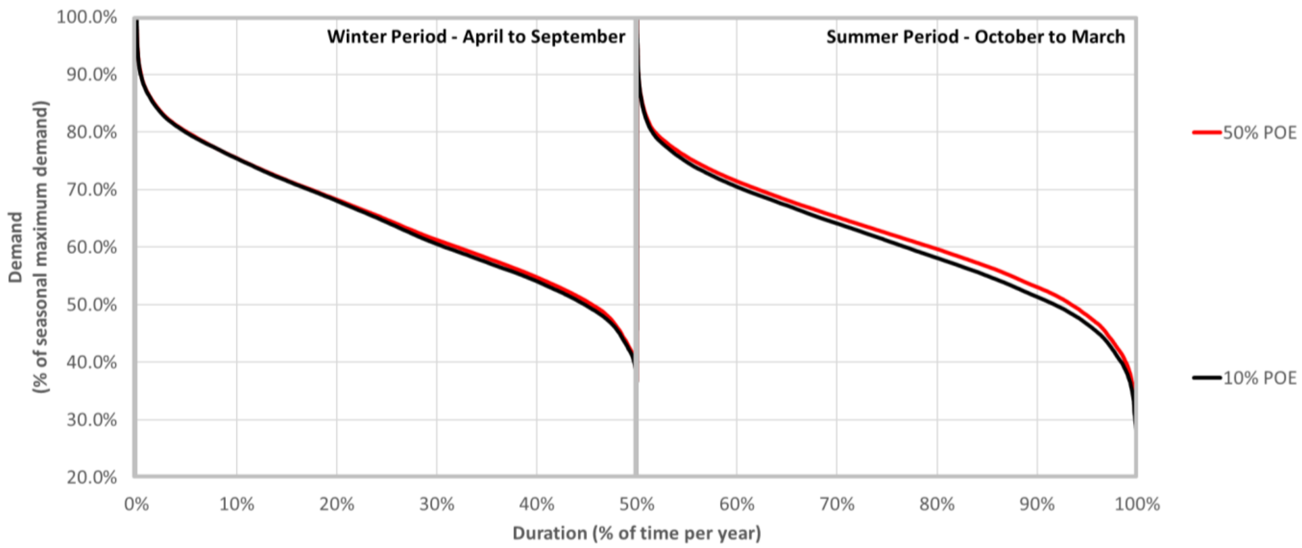
The load-duration curves for ATS-BLTS 66 kV is shown in Figure 3-3 at times of peak demand periods in winter and summer seasons.

Figure 3-3: Load-duration profile for ATS-BLTS 66 kV at peak demand



The shape of the curves are moderately influenced by the coincidence of extreme ambient temperature on working weekdays and the number of times this occurs in any one year. This is illustrated in Figure 3-4 for the full year showing the POE10 and POE50 profiles for winter and summer seasons.

Figure 3-4: Annual load-duration profile for ATS-BLTS 66 kV



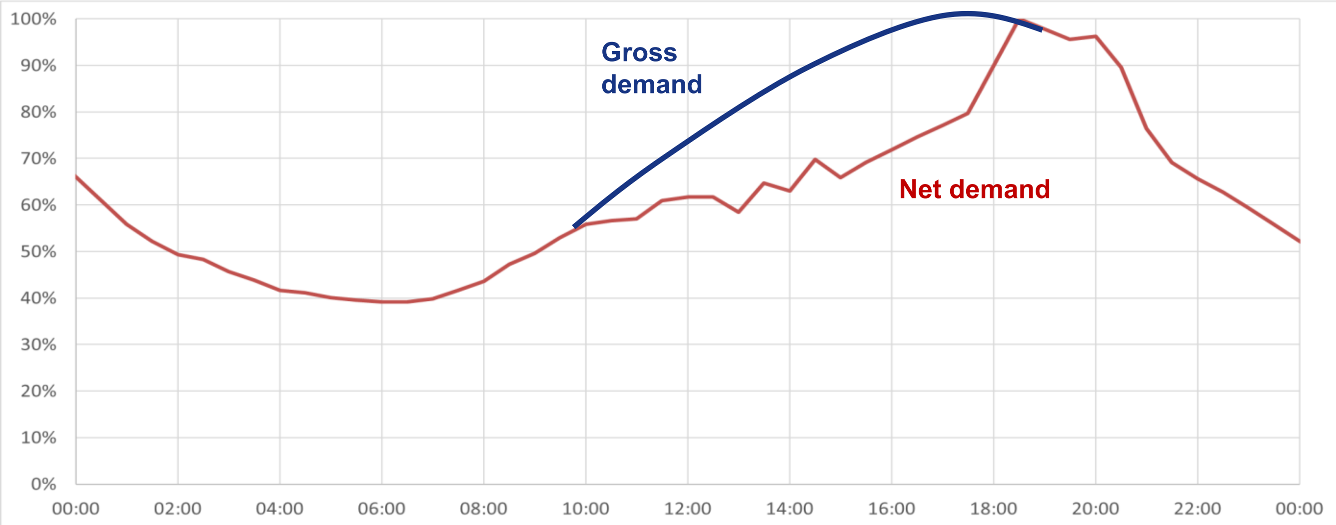
The shape of the net load curves is influenced by the level of distributed roof-top solar PV, with more recent years tapering off rapidly (sharper peak, lower trough) compared to the more historical summers, and compared with the underlying load estimate.

As of 2024, a total of 112 MW capacity of embedded generation is installed on the sub-transmission and distribution systems connected to ATS-BLTS 66 kV. It consists of:

- 43 MW of large scale (>1 MW) embedded generation, which includes 40 MW in the Powercor distribution system and 3 MW in the JEN distribution system; and
- about 69 MW small-commercial and residential rooftop solar PV (<1 MW), which includes 42 MW in the Powercor distribution system and 27 MW in the JEN distribution system.

The typical net daily load profiles at ATS-BLTS 66 kV during the summer peak are shown in Figure 3-5.

Figure 3-5: Daily load profile for ATS-BLTS 66 kV (summer peak demand)



3.2.5 Network asset reliability

Table 3-3 provides a summary of the ATS-BLTS 66 kV transformer reliability information used in the EUE analysis.

Table 3-3: ATS-BLTS 66 kV transformer reliability information[22]

Power Transformer Reliability Quantity	Value	Description
Major forced outage rate (failure rate)	1.0% per annum	A major outage is expected to occur once per 100 transformer-years. In a population of 100 terminal station transformers, expect one major failure of any one transformer per year.
Weighted average of major outage duration (repair time)	2.65 months	On average, 2.65 months is required to return the transformer to service, during which time the transformer is not available for service.
Expected transformer unavailability due to a major outage per transformer-year	0.22%	On average, each transformer would be expected to be unavailable due to major outages for 0.01 x 2.65/12 = 0.22% of the time, or 19 hours per year.

[22] Section 5.4 of the 2024 Transmission Connection Planning Report (TCPR).

4. Proposed assessment methodology

This chapter discusses the proposed assessment methodology for the NPV assessment of options under this RIT-T, including:

- key parameters used for this RIT-T for the cost-benefit assessment include:
  - value of customer reliability;
  - discount rate; and
  - assessment period;
- the approach to estimating option cost; and
- the materiality of each category of market benefits under the RIT-T.

4.1 Assessment parameters

4.1.1 Value of customer reliability

The cost of EUE is calculated using a value of customer reliability (**VCR**), which is an estimate of the value electricity consumers put on having a reliable electricity supply.

JEN and Powercor have applied locational VCR values based on the estimates in the Australian Energy Regulator's (**AER**) Values of Customer Reliability Review published in December 2024[23]. Specifically, applying the AER's VCR estimates for different sectors (i.e., residential, commercial, industrial and agricultural) to terminal station level recent energy composition data, we have calculated the ATS-BLTS 66 kV VCR of $36,544 per MWh as presented in Table 4-1.

Table 4-1: ATS-BLTS 66 kV value of customer reliability

Sector	AER VCR ($/MWh, 2024)	Energy consumption	Weighted VCR ($/MWh)
Residential Suburban	55,100	12.2%	6.748
Residential Regional	38,900	0.0%	0
Agricultural	22,250	0.0%	0
Commercial	34,390	54.6%	18.786
Large Business[24]	33,100	21.5%	7.109
Industrial	33,490	11.6%	3.901
Composite		**100%**	**36,544**

4.1.2 Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. A discount rate of 4.69 per cent is applied at BLTS. The 7.00 per cent central discount rate used in AEMO's 2023 inputs, assumptions and scenarios report[25] (IASR) is intended to be applied for the high bound sensitivity test. For the low bound sensitivity test we intend to use a 2.38 per cent discount rate.

[23] AER 2024 published VCRs. Climate zone 6 suburban applies at BLTS.

[24] Greater than 10 MW.

[25] 2023 Inputs, Assumptions and Scenarios Report, Table 31, Australian Energy Market Operator (AEMO), July 2023.

4.1.3 Assessment period

We intend to undertake the NPV analysis over a fifteen-year period, from 2025 to 2039. We consider that the length of this assessment period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. The assessment period accounts for the expected (moderated) demand growth in the supply area intended to be addressed by the credible options in this RIT-T. The relatively moderate time period proposed to be used for the assessment reflects the possibility that the current options only address the immediate need (due to the moderation of the demand forecasts) and that a further augmentation of BLTS may be needed in future when the major customer data-centre load actually materialises, in which case another RIT-T will be initiated.

Where capital components have asset lives greater than the analysis period, we intend to adopt a residual value approach to incorporating capital costs in the assessment, which will ensure that the capital costs of long-lived options are appropriately captured in the assessment period.

Monetised risks are capped to their year 10 values from year 11 to the end of the evaluation period, reflecting the ten-year demand forecasting period.

4.2 Approach to estimating option costs

The costs for each option have been calculated by AusNet Transmission Group, JEN and Powercor's cost estimation teams based on recent similar project costs and scope. Costs are expected to be within ±30 per cent of the actual cost.

The costs presented in this RIT-T are comprehensive including escalations, overheads, financing charges and management reserve (contingency risk). All cost estimates are escalated to real 2025 dollars based on the information available at the time of preparing this report. Overheads and financing charges comprise approximately 10.7% of the total costs, and contingency risk comprise 5.8%.

We note that social license costs have not been included as they are not expected to be material for this RIT-T.

Ongoing operating and maintenance costs are included in the assessment annually from the year after the capital investment at a level of 1.0 per cent of the capital cost per annum for brownfield sites and 0.5 per cent for greenfield sites.

Land procurement cost is based on estimated market valuation of potential (or existing held) properties in the supply area, plus costs for establishing services and site access.

Where capital components have asset lives greater than the assessment period, we have adopted a residual value approach to incorporating capital costs in the assessment, which ensures that the capital costs of long-lived options are appropriately captured in the assessment period.

4.3 Materiality of market benefits

The RIT-T instrument requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the RIT-T proponent can demonstrate that[26]:

- a particular class (or classes) of market benefit is unlikely to be material in relation to the RIT-T assessment for a specific option, or
- the estimated cost of undertaking the analysis to quantify that benefit would likely be disproportionate to the scale, size and potential benefits of each credible option being considered in the report.

[26] AER, Regulatory Investment Test for Transmission, November 2024, paragraphs 7 and 11.

We consider that changes in involuntary load reduction (i.e., avoided EUE) is the only class of market benefit that will be material to the network options considered in this RIT-T assessment. We will review this expectation at the PADR stage, having regard to any submissions to the PSCR including from non-network option proponents.

We expect that the following classes of market benefits will not be material to the RIT-T assessment for any of the credible network options:

- **Avoided unrelated network expenditure**, as we do not expect the options to affect other proposed network expenditure or the timing of that expenditure;
- **Wholesale market benefits,** including changes in fuel consumption arising through different patterns of generation dispatch changes in voluntary load curtailment, and changes in costs for parties other than JEN and Powercor, because we do not expect the credible options to have a material market on generation dispatch in the wholesale market;
- **Changes in Australia’s greenhouse gas emissions**, as we do not expect the credible options to affect emissions through dispatch, changes in renewable generation curtailment, changes in network losses, or through changes in SF_6 emissions from high-voltage switchgear;
- **Changes in network losses**, as any network losses outside of those that are captured through the network capacity assumptions feeding into the EUE analysis are not expected to be material to the ranking of options;
- **Additional option value**, as we expect that the costs of modelling option value will be disproportionate to any benefits and that there will be limited option value outside of anything captured in the scenario analysis (to the extent that timing or scope of options components, including any non-network components, varies across reasonable scenarios);
- **Changes in safety costs**, as the identified need is not driven by network asset condition. Therefore, this market benefit is not quantified as it is not considered to be relevant with respect to differentiating between options that address the identified need;
- **Changes in ancillary services costs**, as the estimated cost of undertaking the analysis to quantify these changes would likely be disproportionate to the scale of the credible options being considered in this report; and
- **Competition benefits**, because the estimated cost of undertaking the analysis to quantify competition benefits would likely be disproportionate to the scale of the credible options being considered in this report.

5. Technical characteristics a non-network option would need to deliver

The NER and the AER's RIT-T Application Guidelines require that a PCSR must include the technical characteristics of the identified need that a non-network or SAPS option would be required to deliver[27]. This chapter outlines the technical characteristics that a non-network or SAPS option would be required to deliver in the form of network support services, to alleviate the forecast capacity limitations at ATS-BLTS 66 kV.

5.1 Performance requirements

Initial analysis by JEN and Powercor has identified that Option 4 is likely to be the preferred network option with an annualised cost of $1.8 million (real, 2025) which represents the maximum available annual payment that could be available to non-network or SAPS providers (in aggregate) for a network support option.

Based on the results of Table 2-4, the EUE risk exceeds the annualised cost of the preferred network option in the summer of 2027-28, which represents the latest date that a network support service needs to be in place to defer the preferred network option.

As a minimum, a network support option needs to be able to defer the preferred network option by at least one year. To achieve this, the network support option must maintain (or reduce) the EUE from one year to the next, for the duration of the network support agreement. To be eligible for the maximum available annual payment, the network support option must reduce the EUE by at least the same amount as that of the preferred network option.

Network support may also be combined with suitable network augmentation components to reduce the scope of a credible network option. In this case, a lower annual payment would be negotiated to reflect the level of network and the investment that is able to be avoided.

The amount of network support that JEN and Powercor are seeking from a full non-network or SAPS option by summer 2027-28 is 126 MW at ATS-BLTS 66 kV, post-contingent. This would need to increase in the following years according to Table 2-2. By 2030-31, pre-contingent services would also be required, starting from 10 MW at ATS-BLTS 66 kV. Lower levels of support may be able to be combined with other network or non-network solutions, as described above.

The magnitude and duration for ATS-BLTS 66 kV network support services required under various seasonal, loading and network operating conditions (considering the likelihood of those conditions), is detailed in Table 2-2, with the indicative time of day requirements shown in Figure 3-5.

Network support services could include services such as voluntary load reduction (demand response), aggregated distributed energy resources (virtual power plants), or larger-scale dispatchable embedded storage and/or generation resources.

5.2 Submission requirements

Non-network and SAPS service providers interested in providing submissions to alleviate the network limitations outlined in this PSCR are advised to begin engagement with JEN and Powercor as soon as possible. A detailed proposal including the information listed below should be submitted by the requested date. Details required include:

- Name, email address and other contact details of the person making the submission.
- ABN and contact details of the business seeking to contract with us for network support services.
- A detailed description of services to be provided including:
    - Size (MW/MVA/MWh)

[27] NER, clause 5.16.4(b)(3); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.

  - Location(s)
  - Frequency and duration
  - Type of action or technology proposed
  - Proposed dispatching arrangement
  - Availability and reliability performance details
  - Period of notice required to enable the non-network support
  - Proposed contract period and staging (if applicable)
  - Proposed timing for delivery (including timeline to plan and implement).
- High-level electrical layout of the proposed site (if applicable).
- Evidence and track record proving capability and previous experience in implementing and completion of projects of the same type as the proposal.
- Preliminary assessment of the proposal's impact on the EUE network limitations.
- Breakdown of lifecycle cost for providing the service, including:
  - Capital costs (if applicable)
  - Annual operating (i.e. set up and dispatch fees) and maintenance costs
  - Other costs (e.g. availability, project establishment, integration etc.)
  - Tariff assumptions
  - Expected annual payment for providing the non-network solution.
- A method outlining measurement and quantification of the agreed service, including integration of the proposed solution with the network.
- A financial and service performance risk assessment to manage potential risks of non-delivery of service.
- A statement outlining that the non-network service provider is prepared to enter into a Network Support Agreement (**NSA**) (subject to agreeing terms and conditions).
- Letters of support from partner organisations.
- Any special conditions to be included in an NSA.
- Outline relevant social license considerations.

All proposals must satisfy the requirements of any applicable laws, rules and the requirements of any relevant regulatory authority, including following the normal network connection processes where applicable. Any network reinforcement costs required to accommodate the non-network or SAPS solution, or any reliability penalties relating to non-delivery of service, will typically be borne by the proponent of the non-network or SAPS solution.

For further details on JEN and Powercor's processes for engaging and consulting with non-network and SAPS service providers, and for investigating, developing, assessing and reporting on non-network or SAPS options as alternatives to network augmentation, please refer to the Industry Engagement Strategy at the links below.

1. JEN Industry Engagement Strategy.

2. Powercor Industry Engagement Document.

6. Description of potential credible options

This chapter lists and describes options that JEN and Powercor consider may be capable of meeting the identified need. The potential credible options considered to address the identified need include:

- **Option 1** – Do nothing (base case). This not considered a credible option going forward due to the associated EUE risk;
- **Option 2** – Non-network or SAPS solution;
- **Option 3** – Establish a new BLTS North 66 kV bus group; and
- **Option 4** – Upgrade of the existing ATS-BLTS 66 kV bus group.

All of the network options (except for option 1) would increase the thermal capacity of BLTS or result in additional capacity at another terminal station. Table 6-1 below summarises the new thermal capacity ratings that would result from the three network options, compared to the base case in which no investment is undertaken.

Table 6-1: Thermal capacity ratings of each option (MVA)

Rating	Option 1 (base case)	Option 3	Option 4
	ATS-BLTS 66 kV	BLTS North 66 kV	ATS-BLTS 66 kV
Summer (N)	508	530	508
Summer (N-1)	339	265	508
Winter (N)	579	588	579
Winter (N-1)	386	294	579

The different options will all result in lower EUE than in the base case, although the extent/timing of the reduction varies across the options due to the differences in the additional thermal capacity ratings they provide. JEN and Powercor consider that all options reduce EUE to a level consistent with the identified need for this RIT-T.

6.1 Option 1 - Do nothing

The ”Do-nothing” option involves continuing to supply customers serviced by BLTS without any intervention to manage EUE. This is expected to lead to significant supply interruptions and unserved energy under both “N” (system normal) and “N-1” (single contingency) conditions at times of peak demand.

As detailed in Table 2-4, the total combined value of the EUE risk associated with the “Do nothing” option is forecast to increase from $0.00 in 2024-25 to $2.5 million in 2027-28, to $52.9 million by 2033-34 (real, 2025).

In the context of this RIT-T, the “Do nothing” option is used as a base case to which all other credible options will be compared, to identify the option that maximises the present value of net economic benefit. Furthermore, since no incremental expenditure is to be incurred under the “Do nothing” option, the “Do nothing” option is considered a zero-cost and zero-benefit option.

6.2 Option 2 - Non-network or SAPS solution

Non-network or SAPS solutions may be contracted to provide network support services from within the distribution or sub-transmission networks serviced by ATS-BLTS 66 kV to reduce the net maximum demand on ATS-BLTS 66 kV (i.e., reducing the EUE), thereby addressing the identified need (at least in part).

Network support services could include services such as voluntary load reduction (demand response), aggregated distributed energy resources (virtual power plants), or larger-scale dispatchable (or standby) embedded storage and/or generation resources.

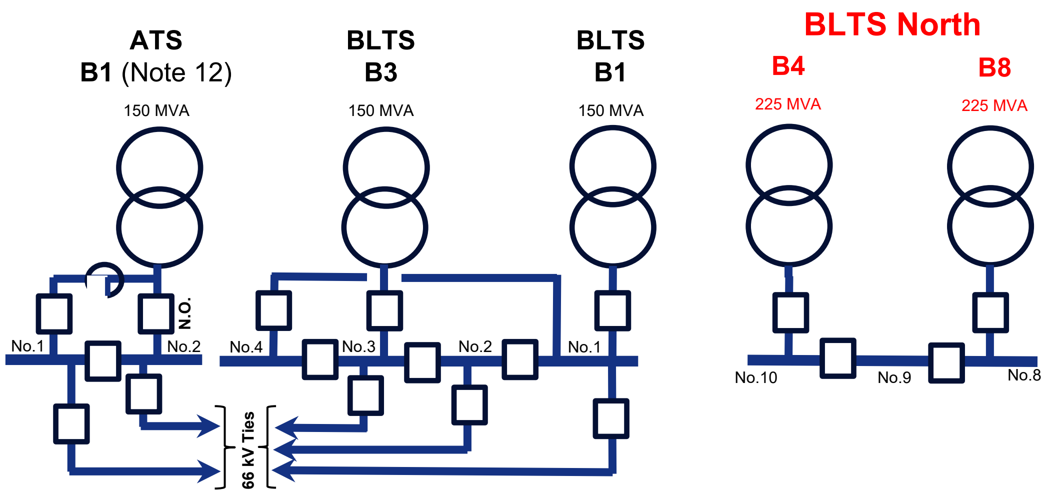
Chapter 5 details the required technical characteristics as well as the maximum fees available to a non-network or SAPS service provider, based on the current preferred network option. Network support may also be combined with suitable network augmentation options to defer or reduce the scope of a credible network option.

JEN and Powercor will consider whether each of the classes of market benefits contemplated by Clause 5.15A.2 of the NER could be relevant for any non-network of hybrid options arising from submissions to this PSCR.

6.3 Option 3 - Establish a new BLTS North 66 kV bus group

This option involves leaving ATS-BLTS 66 kV as is, instead connecting the forecast major customer data-centre load to two new 220/66 kV 225 MVA transformers at BLTS 66 kV in a new, separate indoor bus group designated (BLTS North 66 kV bus group), with the ability to expand to a third 225 MVA transformer in future. A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 6-1.

Figure 6-1: Establish a new BLTS North 66 kV bus group simplified single line diagram (Option 3)



The scope of work required for this option includes:

- A new BLTS 66 kV indoor bus group designated BLTS North, comprising three fully-switched GIS buses (No.8, No.9, and No.10) with four feeder breakers and one transformer incomer per bus) to be housed in a new 66 kV switch-room building, in a vacant location within the northern section of the BLTS site. There is no 66 kV electrical connection made between the existing 66 kV switchyard at BLTS and the new 66 kV indoor bus group.

- Install new B4 and B8 high impedance 220/66 kV 225 MVA transformers.

- Extend (towards the west), the 220 kV switchyard and buses to establish new Bays AA through to AF (inclusive).

- Connect B4 from 220 kV Bus No.4 in Bay AE, single switched via a new 220 kV circuit breaker using overhead 220 kV line, through to the new 66 kV Bus No.10 using 66 kV underground cable.

- Connect B8 from 220 kV Bus No.3 in Bay AE, single switched via a new 220 kV circuit breaker using underground 220 kV cable, through to the new 66 kV Bus No.8 using 66 kV underground cable.

- CTs, VTs, disconnectors, isolators, earth switches, surge arrestors, fittings and other equipment necessary to support the new equipment above.

- Earthworks (civil), earth-grid reinforcement, environmental works (bunding, noise mitigation, fire mitigation etc.), footings and structural works, reinstatements, and other works necessary to support the new equipment.
- Site and building services, auxiliary power supplies, conduits, protection, control and communications systems, and other systems necessary to support the new equipment.
- Interfacing of the new equipment with all existing systems at BLTS including setting and configuration modifications, with feeder unit protection relays that match JEN's remote end protection requirements.
- Labelling and drawing updates and update of all records associated with the installation of the new and modified equipment.
- Planning and building permit approvals for works within the BLTS site (if required).

The estimated capital cost of this network option is $80 million (real, 2025), with ongoing operations and maintenance costs of $0.8 million per annum.

The annualised cost of this option is $4.7 million. Based on this annualised cost, the optimal timing of this option based on the forecast weighted value of EUE at BLTS (as set out in Table 2-4) is before summer 2029-30.

This option has an estimated construction period of two to three years.

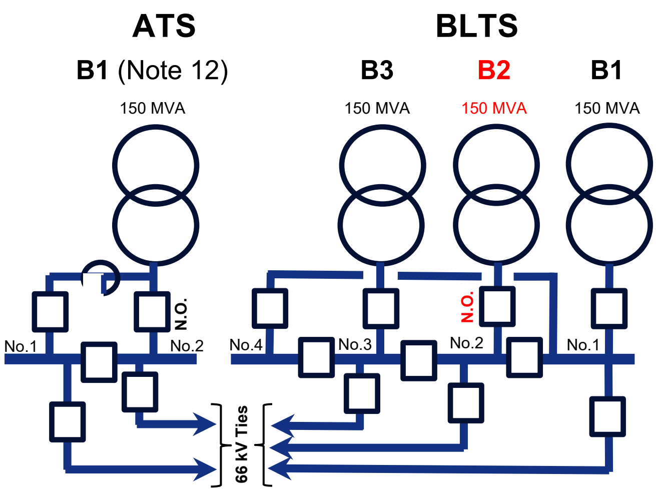
This option is not likely to have a material inter-network impact.

Social licencing risks are considered minor for this option as it only involves work within an existing established brownfield substation in an industrial area and establishment of an indoor 66 kV switchgear building. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

6.4 Option 4 - Upgrade of the existing ATS-BLTS 66 kV bus group

This option involves installing one new 220/66 kV 150 MVA transformer at ATS-BLTS 66 kV to complement the two existing 150 MVA units (with the new B2 transformer on an auto-close scheme to manage short circuit levels), retaining the 66 kV ties with ATS to allow the 220/66 kV 150 MVA transformer at ATS to remain in parallel with BLTS. A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 6-2.

Figure 6-2: Upgrade the existing ATS-BLTS 66 kV bus group simplified single line diagram (Option 4)



The scope of work required for this option includes:

- Install one new B2 220/66 kV 150 MVA transformer at BLTS with impedances to match B1 and B3, with a neutral reactor and new 66 kV outdoor incomer circuit breaker.
- Connect B2 from the 220 kV B5 disconnector at BLTS, through to the existing 66 kV Bus No.2 via 66 kV underground cable.
- CTs, VTs, disconnectors, isolators, earth switches, surge arrestors, fittings and other equipment necessary to support the new equipment above.
- Earthworks (civil), earth-grid reinforcement, environmental works (bunding, noise mitigation, fire mitigation etc.), footings and structural works, reinstatements, and other works necessary to support the new equipment.
- Site and building services, auxiliary power supplies, conduits, protection, control and communications systems, and other systems necessary to support the new equipment.
- Interfacing of the new equipment with all existing systems at ATS and BLTS including setting and configuration modifications, with feeder unit protection relays that match Powercor and JEN’s remote end protection requirements.
- Labelling and drawing updates and update of all records associated with the installation of the new and modified equipment.
- Planning and building permit approvals for works within the BLTS site (if required).

The estimated capital cost of this network option is $29.8 million (real, 2025), with ongoing operations and maintenance costs of $0.3 million per annum.

The annualised cost of this option is $1.8 million. Based on this annualised cost, the optimal timing of this option based on the forecast weighted value of EUE at BLTS (as set out in Table 2-4) is before summer 2027-28.

This option has an estimated construction period of two years.

This option is not likely to have a material inter-network impact.

Social licencing risks are considered minor for this option as it only involves work within an existing established brownfield substation in an industrial area. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

Based on an initial assessment, this option is currently expected to maximise the net market benefits and is therefore likely to be the preferred *network* option. However this conclusion will be confirmed through this RIT-T process.

7. Submissions and next steps

7.1 Request for submissions

JEN and Powercor invite written submissions and enquiries on the matters set out in this PSCR from interested stakeholders. All submissions and enquiries should be titled "**Altona-Brooklyn Terminal Station Capacity Constraint RIT-T**" and directed to both:

Aaron Abbruzzese (JEN)

Data Centre Planning and Delivery Team Leader

PlanningRequest@jemena.com.au

and

Richard Robson (Powercor)

Manager Sub-transmission Planning and Major Connections

rittenquiries@powercor.com.au

The consultation on this PSCR is open for 12 weeks, consistent with the NER requirements[28]. Submissions are due on or before 22 December 2025. Submissions will be published on the Australian Energy Market Operator (**AEMO**), JEN and Powercor websites. If you do not wish for your submission to be published, please clearly stipulate this at the time of lodging your submission.

7.2 Next steps

Following conclusion of the PSCR consultation period, JEN and Powercor will, having regard to any submissions received on the PSCR, prepare and publish a project assessment draft report (**PADR**) including:

- A description of each credible option assessed;
- A summary of, and commentary on, the submissions on the PSCR;
- A quantification of the costs and material market benefit for each credible option, including a detail description of the methodologies used in quantifying costs and material market benefits;
- The results of the net present value analysis for each credible option and explanation of the results; and
- Identification of the proposed preferred option to meet the identified need.

Publication of that report will trigger the second stage of consultation on this RIT-T.

JEN and Powercor intend on publishing the PADR in the first quarter of 2026.

[28] NER, clause 5.16.4(g).

8. Appendix A – RIT-T compliance checklist

This appendix sets out a checklist in Table 8-1 which demonstrates the compliance of this PSCR with the requirements of clause 5.16.4(b) of the NER, version 227.

Table 8-1: PSCR RIT-T compliance checklist

A RIT-T proponent must prepare a report which must include:	Chapter
(1) a description of the identified need;	Chapter 2
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	Chapter 3
(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 or additional supply; (ii) location; and (iii) operating profile;	Chapter 5
(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;	Not Applicable
(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, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	Chapter 6
(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 benefits 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.	Chapter 4 & 6

In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Table 8-2: AER guidelines PSCR compliance checklist

Summary of the requirements:	Chapter
3.5A.2 For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied • the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance;	Chapter 4
4.1 RIT-T proponents are required to describe in each RIT-T report • how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement • how they plan to engage with these stakeholder groups, or • why this project does not require community engagement.	Chapter 6