

Thomastown Supply Area

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



Executive summary

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and AusNet Electricity Services Pty. Ltd. (**AusNet**) are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, serving more than 384,000 and 809,000 customers respectively, within Melbourne's northern, inner western and outer eastern metropolitan areas, and in eastern regional Victoria.

The regulatory investment test for transmission (**RIT-T**) is an economic cost-benefit assessment and consultation process used to assess credible options capable of meeting an identified need. The purpose of a RIT-T is to identify the credible option that maximises the present value of net economic benefit (the preferred option). The process follows the requirements in clauses 5.15A and 5.16 of the National Electricity Rules (**NER**)¹.

The identified need for this RIT-T relates to forecast transmission connection asset capacity limitations at Thomastown Terminal Station (**TTS**), a major supply point into the JEN and AusNet electricity distribution networks. The limitations arise from forecast maximum demand growth, primarily driven by expected major customer and data-centre connections within the Thomastown supply area.

In Victoria, DNSPs have responsibility (under their distribution licences) for planning and directing augmentation of 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 AusNet, in accordance with the requirements of clause 5.16 of the NER and section 4.2 of the RIT-T Application Guidelines².

This project specification consultation report (**PSCR**) is the first stage of the **Thomastown Supply Area 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

TTS supplies electricity to more than 177,477 customers across the Thomastown supply area including major geographic centres such as Broadmeadows, Bundoora, Campbellfield, Coburg, Coolaroo, Heidelberg, Preston, Lalor, Macleod, Reservoir, Thomastown and Watsonia.

Due to expected increases in electricity demand within the Thomastown supply area from major customer and data-centre connections, the expected unserved energy (**EUE**) associated with capacity limitations at TTS is forecast to grow if action is not taken, resulting in a deterioration of supply reliability for customers.

The identified need for this RIT-T is to maintain electricity supply reliability and mitigate forecast increases in EUE for those customers supplied from TTS within the Thomastown supply area, while enabling the connection of new major customer and data-centre load.

Addressing this identified need through prudent investment in a network, non-network or SAPS option is expected to result in a positive net economic benefit.

The need for this investment was identified in the 2025 Transmission Connection Planning Report (**TCPR**), published jointly by the Victorian DNSPs³.

¹ [National Electricity Rules](#), version 253, Australian Energy Market Commission (AEMC), 2026.

² [Regulatory investment test for transmission Application guidelines](#), Australian Energy Regulator (AER), 2024.

³ [Transmission Connection Planning Report](#), Victorian Distribution Network Service Providers, 2025.

Potential credible options

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

- **Option 1** – Non-network or SAPS solution;
- **Option 2** – Install two additional transformers at TTS (B6 & B7); and
- **Option 3** – Establish a new two-transformer Somerton Terminal Station (SOTS).

The potential credible options are assessed against a Do-nothing base case.

Initial analysis by JEN and AusNet indicates that Option 2 may be the preferred *network* option, subject to completion of the RIT-T assessment process.

The estimated capital cost of the most expensive credible option to address the identified need exceeds the trigger of \$8 million⁴ for undertaking a RIT-T (and the estimated capital cost of all other credible options also exceeds this threshold).

Submissions

JEN and AusNet invite written proposals for alternative options, submissions and enquiries on the matters set out in this PSCR from interested stakeholders.

All submissions and enquiries should be titled “**Thomastown Supply Area RIT-T**” and directed to both:

George Tziokas (JEN)

Grid Planning and Reliability Manager

PlanningRequest@jemena.com.au

and

Ali Kharrazi (AusNet)

Manager, Sub-Transmission Network Planning

ritconsultations@ausnetservices.com.au

The consultation on this PSCR is open for 12 weeks, consistent with the NER requirements⁵. Submissions are due on or before **22 December 2026**.

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

⁴ [AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test](#), Australian Energy Regulator (AER).

⁵ NER, clause 5.16.4(g).

Next steps

Following conclusion of the PSCR consultation period, JEN and AusNet 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 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 AusNet intend on publishing the PADR in the **first quarter of 2027**.

Table of contents

Executive summary	ii
Glossary.....	vii
Abbreviations	ix
1. Introduction	1
2. Description of the identified need	3
2.1 Supply area.....	3
2.1.1 Electricity network servicing the supply area.....	3
2.1.2 Customer demand for electricity	4
2.2 Identified need	4
3. Assumptions used in identifying the identified need	9
3.1 Overview of approach to the NPV analysis.....	9
3.2 Input assumptions.....	10
3.2.1 Network asset ratings.....	10
3.2.2 Forecast maximum demand.....	10
3.2.3 Load transfer capability	14
3.2.4 Annual load profile	14
3.2.5 Network asset reliability	16
4. Proposed assessment methodology	17
4.1 Assessment parameters	17
4.1.1 Value of customer reliability	17
4.1.2 Discount rate.....	17
4.1.3 Assessment period	18
4.2 Approach to estimating option costs	18
4.3 Materiality of market benefits.....	18
5. Technical characteristics a non-network option would need to deliver	20
5.1 Performance requirements	20
5.2 Submission requirements	20
6. Description of potential credible options	22
6.1 Do-nothing	22
6.2 Option 1 - Non-network or SAPS solution.....	22
6.3 Option 2 – Install two additional transformers at TTS (B6 & B7).....	23
6.4 Option 3 – Establish a new two-transformer Somerton Terminal Station (SOTS).....	25
7. Submissions and next steps.....	27
7.1 Request for submissions	27
7.2 Next steps.....	27
8. Appendix A – RIT-T compliance checklist.....	28

List of tables

Table 2-1: TTS net energy consumption (GWh per annum, 2025)	4
Table 2-2: Forecast capacity limitations on the TTS12 66 kV bus group	5
Table 2-3: Forecast capacity limitations on the TTS34 66 kV bus group	6
Table 2-4: Forecast EUE at TTS (Do-nothing).....	8
Table 2-5: Forecast weighted value of EUE at TTS (Do-nothing)	8
Table 3-1: TTS 66 kV thermal capacity cyclic ratings (MVA) - existing	10
Table 3-2: Forecast maximum demand at TTS12 group (MVA)	11
Table 3-3: Forecast maximum demand at TTS34 group (MVA)	12
Table 3-4: TTS 220/66 kV transformer reliability information	16
Table 4-1: TTS value of customer reliability	17
Table 6-1: Thermal capacity ratings of each option (MVA)	22
Table 8-1: PSCR RIT-T compliance checklist.....	28
Table 8-2: AER guidelines PSCR compliance checklist	29

List of figures

Figure 1-1: RIT-T process flow chart	2
Figure 2-1: TTS (12/34) 66 kV simplified single line diagram (existing)	3
Figure 2-2: TTS12 66 kV bus group EUE risk costs (including impact of load transfer capability).....	7
Figure 2-3: TTS34 66 kV bus group EUE risk costs (including impact of load transfer capability).....	7
Figure 3-1: Summer period maximum demand forecasts for TTS12 group	11
Figure 3-2: Winter period maximum demand forecasts for TTS12 group	12
Figure 3-3: Summer period maximum demand forecasts for TTS34 group	13
Figure 3-4: Winter period maximum demand forecasts for TTS34 group	13
Figure 3-5: Load-duration curve for TTS12 group at peak demand	14
Figure 3-6: Load-duration curve for TTS34 group at peak demand	14
Figure 3-7: Daily load profile for TTS12 group (summer peak demand)	15
Figure 3-8: Daily load profile for TTS34 group (summer peak demand)	15
Figure 6-1: Install two additional transformers at TTS (B6 & B7) 66 kV simplified single line diagram (Option 2)	23
Figure 6-2: Establish a new two-transformer SOTS simplified single line diagram (Option 3)	25

Glossary

Distributor	A distribution network service provider (DNSP).
Expected unserved energy (EUE)	The probability weighted, average annual energy demanded (by customers) but not supplied. The EUE is valued for a cost-benefit analysis by multiplying it by 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, as a result of a network limitation.
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	The highest amount of electrical power delivered (or forecast to be delivered) for a particular period (summer and/or winter) and year.
Network	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. Augmentation usually results from increasing customer demand.
Network capacity	The network's capability to transfer electricity to customers, determined from network asset ratings.
Network limitation	A network asset whose maximum demand is forecast to exceed its capacity under system normal or single contingency conditions.
Non-network option	Any measure to reduce or curtail peak demand and/or increase local or distributed generation/supply/storage options.
Probability of Exceedance (POE)	The likelihood that a given level of forecast maximum demand 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.

Single 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 assets.
Standalone 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 32.9°C, with a typical maximum ambient temperature of 42°C and an overnight ambient temperature of 23.8°C, with the demand level expected to be exceeded every ten years.
POE50 (summer)	Refers to an average daily ambient temperature of 29.4°C, with a typical maximum ambient temperature of 38.0°C and an overnight ambient temperature of 20.8°C, with the demand level expected to be exceeded every two years.
POE50 and POE10 (winter)	Refers to an average daily ambient temperature of 7°C, with a typical maximum ambient temperature of 10°C and an overnight ambient temperature of 4°C, with the demand level 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
BD	Broadmeadows Zone Substation
BMS	Broadmeadows South Zone Substation
CN	Coburg North Zone Substation
COO	Coolaroo Zone Substation
CPI	Consumer Price Index
CS	Coburg South Zone Substation
DNSP	Distribution Network Service Provider (distributor)
EP / EPN	East Preston Zone Substation
EUE	Expected Unserved Energy
GWh	Gigawatt hour
IASR	Inputs, Assumptions and Scenarios Report
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo-Volts
MVA	Mega Volt Ampere
MVA _r	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System Normal Condition
N.O.	Normally Open
N-1	Single Contingency Condition
NEI	Customer Zone Substation
NEL	Customer Zone Substation
NER	National Electricity Rules
NH	North Heidelberg Zone Substation
NPV	Net Present Value
NSA	Network Support Agreement
O&M	Operations and Maintenance
PADR	Project Assessment Draft Report
POE	Probability of Exceedance
PSCR	Project Specification Consultation Report
PTN	Preston Zone Substation
PV	Photovoltaic Panels
RIT-T	Regulatory Investment Test for Transmission
SAPS	Stand Alone Power System
SOTS	Somerton Terminal Station (future)
TCPR	Transmission Connection Planning Report
TT	Thomastown Zone Substation
TTS	Thomastown Terminal Station
VCO	Customer Zone Substation
VCR	Value of Customer Reliability
WT	Watsonia Zone Substation

1. Introduction

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and AusNet Electricity Services Pty. Ltd. (**AusNet**) are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, serving more than 384,000 and 809,000 customers respectively, within Melbourne's northern, inner western and outer eastern metropolitan areas, and in eastern regional Victoria.

The regulatory investment test for transmission (**RIT-T**) is an economic cost-benefit assessment and consultation process used to assess credible options capable of meeting an identified need. The purpose of a RIT-T is to identify the credible option that maximises the present value of net economic benefit (the preferred option). The process follows the requirements in clauses 5.15A and 5.16 of the National Electricity Rules (**NER**)⁶.

JEN and AusNet are undertaking this RIT-T to evaluate options to maintain supply reliability within the Thomastown supply area, while enabling connection of new major customer and data-centre load (the identified need).

Options investigated in this RIT-T aim to mitigate increasing expected unserved energy (**EUE**), resulting in a forecast deterioration of power supply reliability. The capital cost of credible options to address this identified need within the Thomastown supply area is above the RIT-T cost threshold of \$8 million⁷, and so has triggered the requirement for a RIT-T.

This project specification consultation report (**PSCR**) is the first stage of the **Thomastown Supply Area RIT-T** consultation process and has been jointly prepared by JEN (as the lead proponent) and AusNet in accordance with section 4.2 of the RIT-T Application Guidelines⁸. 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 AusNet are seeking to address;
- **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 AusNet 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 AusNet industry engagement registers to make a formal written submission on this PSCR.

The need for this investment was identified in the 2025 Transmission Connection Planning Report (**TCPR**)⁹, published jointly by the Victorian DNSPs.

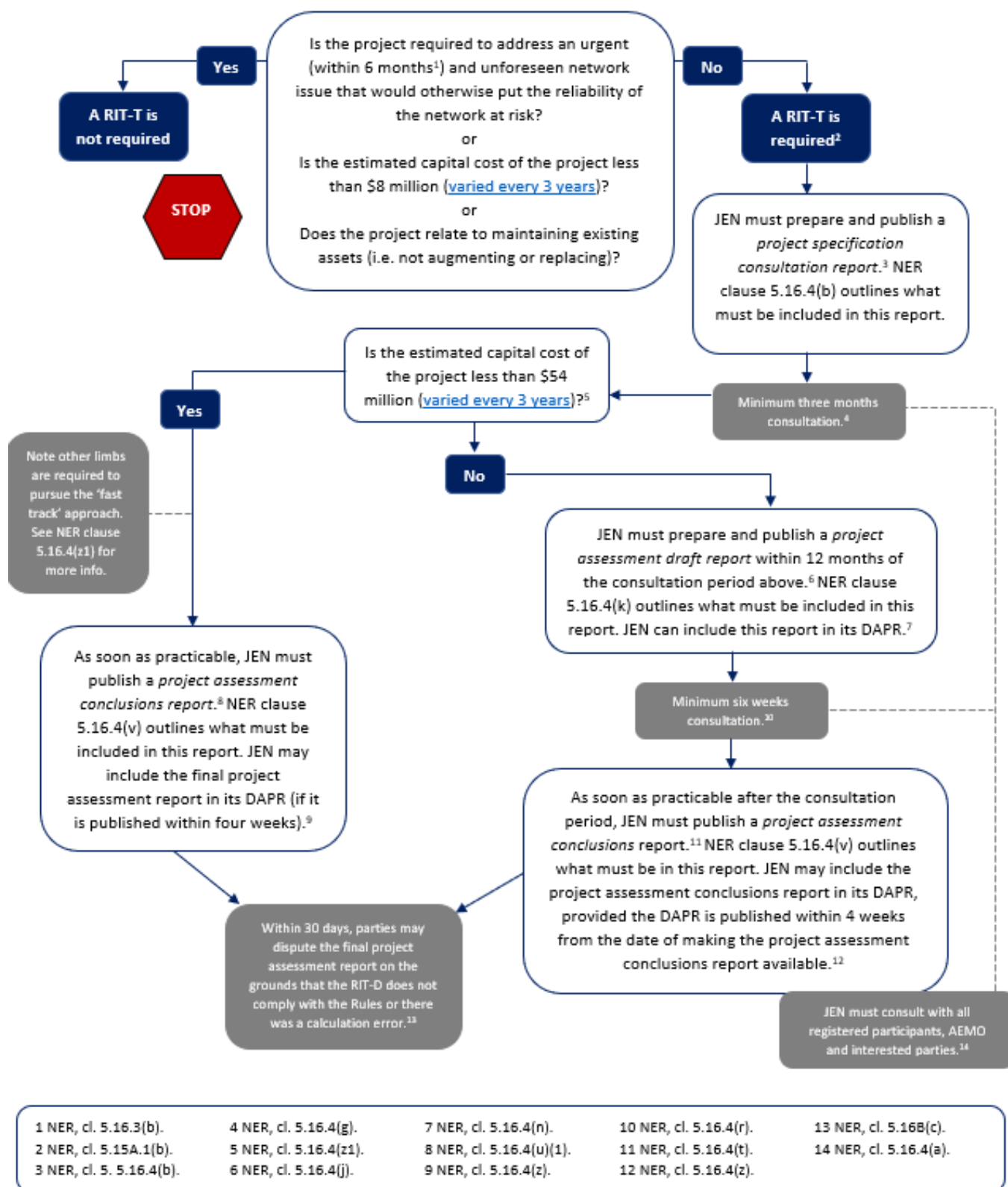
⁶ [National Electricity Rules](#), version 253, Australian Energy Market Commission (AEMC), 2026.

⁷ [AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test](#), Australian Energy Regulator (AER)..

⁸ [Regulatory investment test for transmission Application guidelines](#), Australian Energy Regulator (AER), 2024.

⁹ [Transmission Connection Planning Report](#), Victorian Distribution Network Service Providers, 2025.

Figure 1-1: RIT-T process flow chart



2. Description of the identified need

The NER and the RIT-T Application Guidelines require that a PSCR must include a description of the identified need¹⁰. This chapter discusses the role of Thomastown Terminal Station (TTS) in providing electricity network services and the identified need associated with the forecast capacity limitations of its 66 kV bus groups. 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

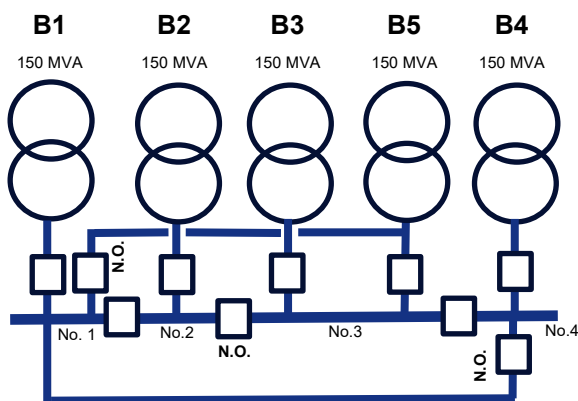
TTS is located in the north of Greater Melbourne. It is the main transmission supply point for major geographic centres such as Broadmeadows, Bundoora, Campbellfield, Coburg, Coolaroo, Heidelberg, Preston, Lalor, Macleod, Reservoir, Thomastown and Watsonia.

Electricity demand at TTS is forecast to experience significant growth, with JEN receiving a number of major customer and data-centre connection requests for the Thomastown supply area, with some connections now proceeding to construction. TTS is expected to exceed its full capacity within the next few years.

2.1.1 Electricity network servicing the supply area

TTS has five 220/66 kV 150 MVA transformers and is a summer critical station. Under system normal conditions, its B1 and B2 transformers are operated in parallel as one group (TTS12), and supply the No.1 and No.2 66 kV buses. The B3, B4 and B5 transformers are operated in parallel as a separate group (TTS34) and supply the No.3 and No.4 66 kV buses. The 66 kV bus 2-3 and bus 1-4 tie circuit breakers are operated open to limit the maximum prospective fault levels on the four 66 kV buses to within the switchgear ratings. This is illustrated in Figure 2-1.

Figure 2-1: TTS (12/34) 66 kV simplified single line diagram (existing)



The B5 transformer operates as a loaded hot standby, meaning it normally supplies load within the TTS34 group but can automatically transfer to the TTS12 group following an outage. Therefore, an unplanned transformer outage of any one of the five transformers at TTS will result in both the TTS12 and TTS34 groups being comprised of two transformers each.

Given this configuration, load demand on the TTS12 group must be kept within the capabilities of two transformers at all times or load shedding may occur. Furthermore at times when B5 is supplying the TTS12 group, load demand on the TTS34 group must also be kept within the capabilities of two transformers.

The cyclic rating of the TTS12 group with all plant in service and with one of its two 220/66 kV 150 MVA transformers out of service is 335 MVA. The cyclic rating of the TTS34 group with all plant in service is 479 MVA, and with one of its three 220/66 kV 150 MVA transformers out of service, reduces to 319 MVA (summer and winter).

¹⁰ NER, clause 5.16.4(b)(1); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.

2.1.2 Customer demand for electricity

More than 177,477 customers within the Thomastown supply area rely on TTS for their electricity supply. Commercial customers currently account for 50.2% of the total annual energy supplied by TTS followed by residential then industrial customers as shown in Table 2.1.

Table 2-1: TTS net energy consumption (GWh per annum, 2025)

Customer Type	TTS12 group	TTS34 group	TTS total	Proportion
Commercial	442	546	988	50.2%
Residential	327	405	732	37.2%
Industrial	110	136	246	12.5%
Agricultural	1	1	2	0.1%
Total	880	1,088	1,968	100%

There have been numerous data-centre and major load connection enquiries in the Thomastown supply area over the last three years, with many enquiries needing feasibility assessments across multiple alternative locations. Several enquiries are now proceeding to formal connection applications and offers, with connection options frequently being tested by the applicants competitively across different distributors. With some connections now proceeding to construction, TTS is expected to exceed its full capacity within the next few years.

Section 3.2.2 provides an overview of the forecast maximum demand that underpins the identified need, with growth dominated by the expected connection of the *committed* major customer and data-centre loads.

Given the uncertainty that many of the remaining *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 AusNet intend to further test the uncertainty of future loads in the cost-benefit assessment in the project assessment draft report (**PADR**) through the adoption of scenarios reflecting differing demand forecasts.

2.2 Identified need

Due to expected increases in electricity demand within the Thomastown supply area from major customer and data-centre connections, the EUE associated with capacity limitations on the TTS 66 kV bus groups is forecast to grow if action is not taken, resulting in a deterioration of supply reliability for customers.

The identified need for this RIT-T is to maintain electricity supply reliability and mitigate forecast increases in EUE, while enabling the connection of new major customer and data-centre load. Addressing this identified need through prudent investment in a network, non-network or standalone power system (**SAPS**) option is expected to result in a positive net economic benefit.

There are two drivers of EUE at TTS - 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 TTS has load transfer capability available at the 22 kV distribution feeder level. This capability allows JEN and AusNet to manage some EUE risk, by transferring load away from TTS to surrounding terminal stations using spare capacity through the distribution network.

Table 2-2 summarises the forecast capacity limitations on the TTS12 66 kV bus group, considering the impacts of the committed major customer and data-centre connections, and the available load transfer capacity.

Table 2-2: Forecast capacity limitations on the TTS12 66 kV bus group

TTS12 group	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Load at risk above 'N' (MVA)										
Summer POE10	0	0	0	0	0	0	0	0	0	0
Winter POE10	0	0	0	0	0	0	0	0	0	0
Summer POE50	0	0	0	0	0	0	0	0	0	0
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	0	0	0	0
Winter POE10	0	0	0	0	0	0	0	0	0	0
Summer POE50	0	0	0	0	0	0	0	0	0	0
Winter POE50	0	0	0	0	0	0	0	0	0	0
Load at risk above 'N-1' (MVA) ¹¹										
Summer POE10	109	111	113	113	114	117	121	121	122	122
Winter POE10	24	29	33	37	40	45	47	49	49	49
Summer POE50	73	75	77	79	81	85	85	86	86	86
Winter POE50	20	25	29	34	37	41	43	45	45	46
Time at risk above 'N-1' (h pa)										
Summer POE10	312	323	335	336	346	374	406	407	413	413
Winter POE10	31	49	74	103	125	175	211	227	229	232
Summer POE50	137	144	151	161	169	182	184	187	188	188
Winter POE50	18	37	51	82	101	129	156	172	184	196
Weighted EUE ¹²										
'N' EUE (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
'N-1' EUE (MWh)	21.1	22.8	24.8	27.0	29.3	33.6	36.6	37.7	38.5	39.0
Total EUE ¹³ (MWh)	21.1	22.8	24.8	27.0	29.3	33.6	36.6	37.7	38.5	39.0
Value of EUE (\$m ¹⁴)	0.9	0.9	1.0	1.1	1.2	1.4	1.5	1.6	1.6	1.6

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 escalated estimate of VCR¹⁵ as discussed further in section 4.1.1.

The EUE for the TTS12 bus group is estimated to have a value to consumers of \$0.9 million in 2027, \$1.0 million in 2029, and \$1.6 million in 2036 (real, 2026).

¹¹ Takes into account that the B5 auto-changeover to the TTS12 group may not be feasible while TTS34 is operating above its N-1 rating.

¹² 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.

¹³ The total EUE is the summation of the EUE contribution during 'N-1' single contingency conditions (considering asset unavailability) capped to the rating of one transformer, and the EUE contribution during 'N' system normal conditions, considering the demand profile and seasonal ratings throughout the year.

¹⁴ Real 2026.

¹⁵ [Values of Customer Reliability](#), Australian Energy Regulator (AER), 2025.

Table 2-3 summarises the forecast capacity limitations on the TTS34 66 kV bus group, considering the impacts of the committed major customer and data-centre connections, and the available load transfer capacity.

Table 2-3: Forecast capacity limitations on the TTS34 66 kV bus group

TTS34 group	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Load at risk above ‘N’ (MVA)										
Summer POE10	0	0	22	21	25	31	38	42	44	44
Winter POE10	0	0	37	43	48	55	60	61	61	61
Summer POE50	0	0	3	3	6	12	19	22	24	24
Winter POE50	0	0	21	27	31	38	43	45	45	46
Time at risk above ‘N’ (h pa)										
Summer POE10	0	0	3	3	3	5	7	8	9	9
Winter POE10	0	0	46	59	70	90	118	124	124	123
Summer POE50	0	0	1	1	1	1	3	3	4	4
Winter POE50	0	0	12	21	32	47	60	64	65	66
Load at risk above ‘N-1’ (MVA)										
Summer POE10	38	76	160							
Winter POE10	38	83	160							
Summer POE50	19	58	160							
Winter POE50	21	66	160							
Time at risk above ‘N-1’ (h pa)										
Summer POE10	14	47	324	323	336	364	392	406	413	413
Winter POE10	99	474	2,011	2,075	2,133	2,218	2,283	2,296	2,296	2,296
Summer POE50	5	32	244	244	257	284	312	327	334	334
Winter POE50	31	325	1,820	1,891	1,944	2,019	2,081	2,097	2,103	2,109
Weighted EUE ¹⁶										
‘N’ EUE (MWh)	0.0	0.0	202	351	520	854	1,226	1,331	1,357	1,376
‘N-1’ EUE (MWh)	3.5	59.8	829	884	931	1,005	1,069	1,087	1,093	1,096
Total EUE ¹⁷ (MWh)	3.5	59.8	1,032	1,235	1,451	1,858	2,295	2,418	2,449	2,471
Value of EUE (\$m ¹⁸)	0.1	2.5	42.6	51.0	59.9	76.8	95.0	100	101	102

The EUE for the TTS34 bus group is estimated to have a value to consumers of \$0.1 million in 2027, \$42.6 million in 2029, and \$102 million in 2036 (real, 2026).

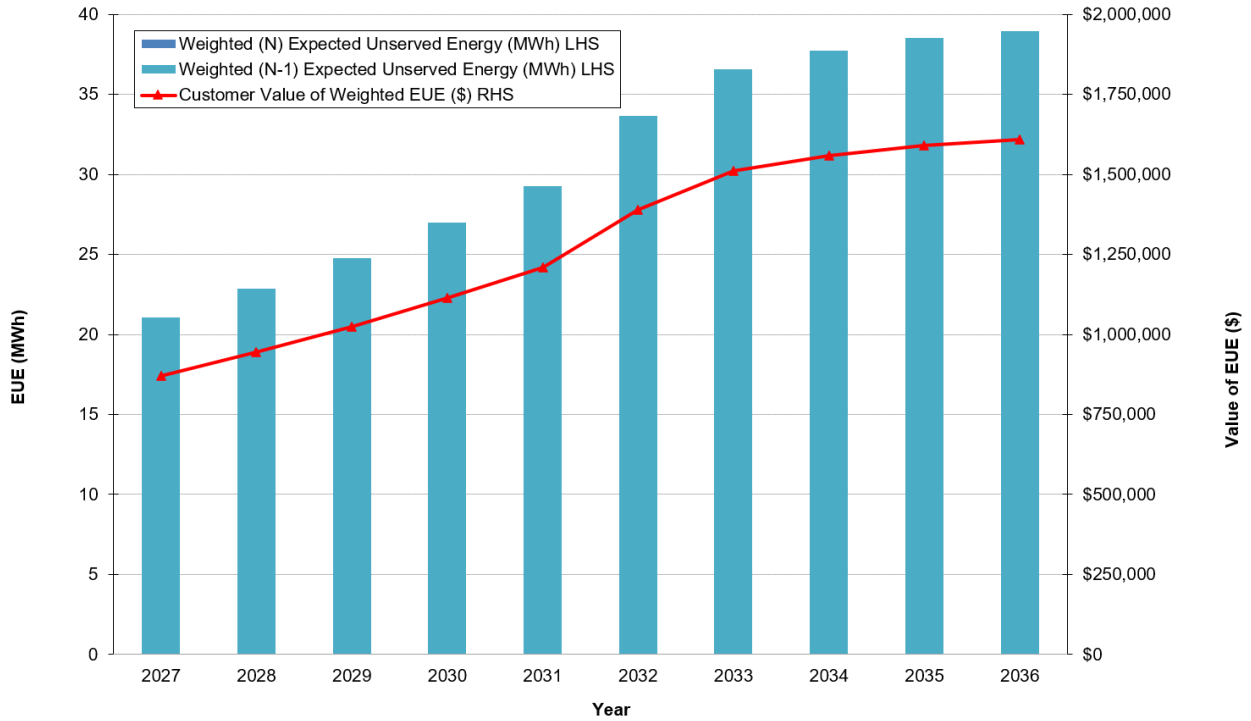
¹⁶ 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE, also considering the risk reduction provided by the available load transfer capabilities and the likelihood of the operating conditions. This weighting is consistently used by the Victorian DNSPs in its TCPR.

¹⁷ The total EUE is the summation of the EUE contribution during 'N-1' single contingency conditions (considering asset unavailability) capped to the rating of one transformer, and the EUE contribution during 'N' system normal conditions, considering the demand profile and seasonal ratings throughout the year.

¹⁸ Real 2026.

The key elements of the Do-nothing supply reliability risk under the base case are shown in Figure 2-2 for the TTS12 66 kV bus group, considering the impacts of available transfer capacity.

Figure 2-2: TTS12 66 kV bus group EUE risk costs (including impact of load transfer capability)



The key elements of the Do-nothing supply reliability risk under the base case are shown in Figure 2-3 for the TTS34 66 kV bus group, considering the impacts of available transfer capacity.

Figure 2-3: TTS34 66 kV bus group EUE risk costs (including impact of load transfer capability)

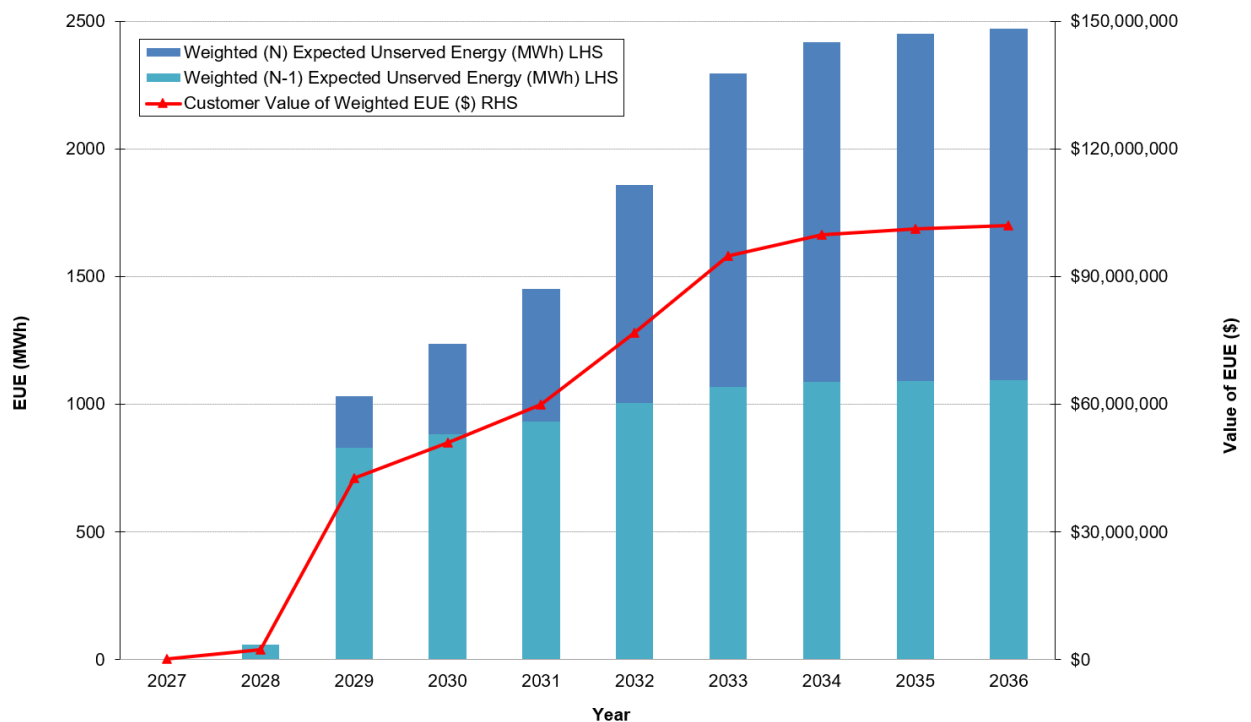


Table 2-4 summarises the forecast total EUE at TTS and Table 2-5 summarises the value of the EUE (as per the totals from Table 2-2 and Table 2-3).

Table 2-4: Forecast EUE at TTS (Do-nothing)

EUE (MWh pa)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
POE50 (N)	-	-	72.4	163	277	525	816	903	935	962
POE50 (N-1)	14.6	61.8	793	850	897	971	1,036	1,056	1,063	1,068
POE10 (N)	-	-	505	791	1,088	1,622	2,182	2,329	2,341	2,340
POE10 (N-1)	47.9	131	997	1,054	1,108	1,195	1,267	1,286	1,290	1,290
Total (Weighted¹⁹)	24.6	82.6	1,056	1,262	1,481	1,892	2,331	2,456	2,488	2,510

Table 2-5: Forecast weighted value of EUE at TTS (Do-nothing)

TTS EUE (\$m, real 2026)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Weighted value of EUE	1.02	3.41	43.6	52.1	61.2	78.2	96.3	101	103	104

¹⁹ 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 RIT-T Application Guidelines require that a PSCR include the assumptions used in identifying the identified need²⁰. This chapter details those assumptions.

First, we set out the probabilistic planning approach and input assumptions applied by JEN and AusNet 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 AusNet 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 requirements²¹, Cost Benefit Analysis guidelines²² and RIT-T Application Guidelines²³, JEN and AusNet 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, subject to limitations in the construction lead time. The proposed assessment method for this RIT-T is set out in more detail in chapter 4.

In planning the network, JEN and AusNet apply a probabilistic planning approach that balances reliability 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).

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.

Having identified the service level reliability risk, JEN and AusNet 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 next stage of the RIT-T process, 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 and maintenance costs.

²⁰ NER, clause 5.16.4(b)(2); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.

²¹ [Regulatory investment test for transmission](#), Australian Energy Regulator (AER), 2024.

²² [Cost Benefit Analysis guideline](#), Australian Energy Regulator (AER), 2024.

²³ [Regulatory investment test for transmission Application guidelines](#), Australian Energy Regulator (AER), 2024.

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

- calculating the preferred option's annualised implementation and ongoing costs; and
- 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 TTS is limited by the thermal rating of its 220/66 kV 150 MVA transformers. Table 3-1 provides a summary of the capability of the two TTS 66 kV bus groups for "N" and "N-1" conditions during summer and winter (maximum demand) periods.

Table 3-1: TTS 66 kV thermal capacity cyclic ratings (MVA) - existing

Rating	TTS12 group	TTS34 group
Summer (N)	335	479
Summer (N-1)	335	319
Winter (N)	335	479
Winter (N-1)	335	319

JEN and AusNet 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 at TTS 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 periods²⁴, taking into consideration the forecast increases in major customer and data-centre load.

²⁴ Victorian electricity demand is sensitive to ambient temperature. Forecast maximum demand is based on the highest demand during extreme ambient temperature conditions that could occur (on average) once every ten years (POE10), and during temperature conditions that could occur once every two years (POE50). Summer period is from October to March; winter period is from April to September.

Table 3-2 provides a summary of the forecast maximum demand for the TTS12 group during summer and winter (maximum demand) periods. Values in **red** indicate that the N-1 rating is exceeded. Values in **red** indicate that N rating is exceeded.

Table 3-2: Forecast maximum demand at TTS12 group (MVA)

TTS12 group	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Summer POE10	277	279	281	281	282	285	289	289	290	290
Winter POE10	192	197	201	205	209	213	216	217	217	217
Summer POE50	241	243	245	247	249	253	253	254	254	254
Winter POE50	188	193	198	202	205	209	212	213	214	214

The TTS12 group is expected to remain within its N and N-1 rating for the entire ten-year forecast period²⁵.

Figure 3-1 shows the POE10 and the POE50 forecasts of maximum demand for the TTS12 group during summer periods relative to its capacity.

Figure 3-1: Summer period maximum demand forecasts for TTS12 group

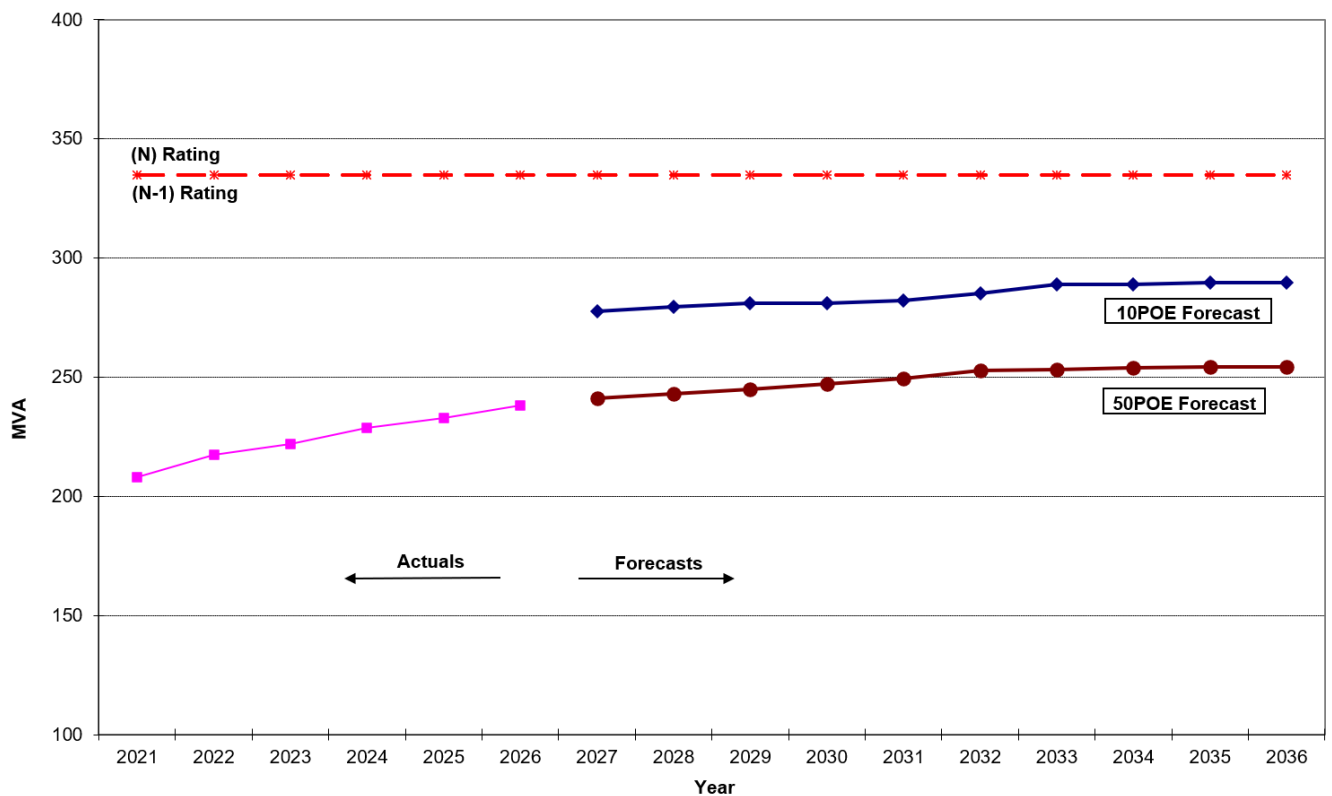


Figure 3-2 shows the POE10 and the POE50 forecasts maximum demand for the TTS12 group during winter periods relative to its capacity.

²⁵ Subject to availability of B5 auto-changeover to the TTS12 group, which may not be feasible while TTS34 is operating above its N-1 rating.

Figure 3-2: Winter period maximum demand forecasts for TTS12 group

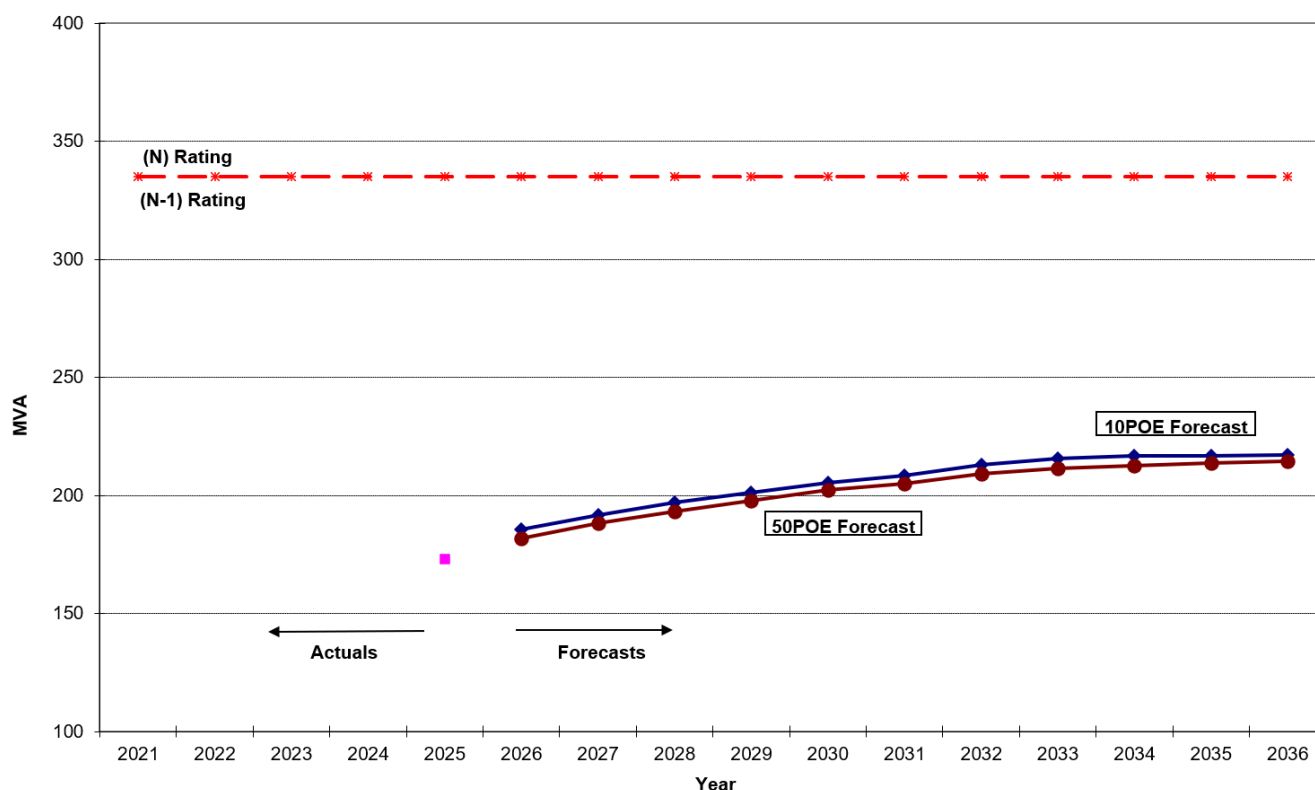


Table 3-3 provides a summary of the forecast maximum demand for the TTS34 group during summer and winter (maximum demand) periods. Values in **red** indicate that the N-1 rating is exceeded. Values in **red** indicate that N rating is exceeded.

Table 3-3: Forecast maximum demand at TTS34 group (MVA)

TTS34 group	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Summer POE10	380	418	<u>532</u>	<u>532</u>	<u>535</u>	<u>542</u>	<u>549</u>	<u>553</u>	<u>554</u>	<u>554</u>
Winter POE10	380	426	<u>548</u>	<u>554</u>	<u>558</u>	<u>565</u>	<u>571</u>	<u>572</u>	<u>572</u>	<u>572</u>
Summer POE50	361	400	<u>514</u>	<u>514</u>	<u>517</u>	<u>523</u>	<u>529</u>	<u>533</u>	<u>534</u>	<u>534</u>
Winter POE50	363	409	<u>531</u>	<u>537</u>	<u>542</u>	<u>548</u>	<u>554</u>	<u>555</u>	<u>556</u>	<u>556</u>

The TTS34 group is expected to exceed its N rating by 2029 for all demand categories. This bus group is already exceeding its N-1 rating.

The maximum demand growth at TTS is predominately due to the growth in major customer and data-centre load within the Thomastown supply area.

Figure 3-3 shows the POE10 and the POE50 forecasts of maximum demand for the TTS34 group during summer periods relative to its capacity.

Figure 3-3: Summer period maximum demand forecasts for TTS34 group

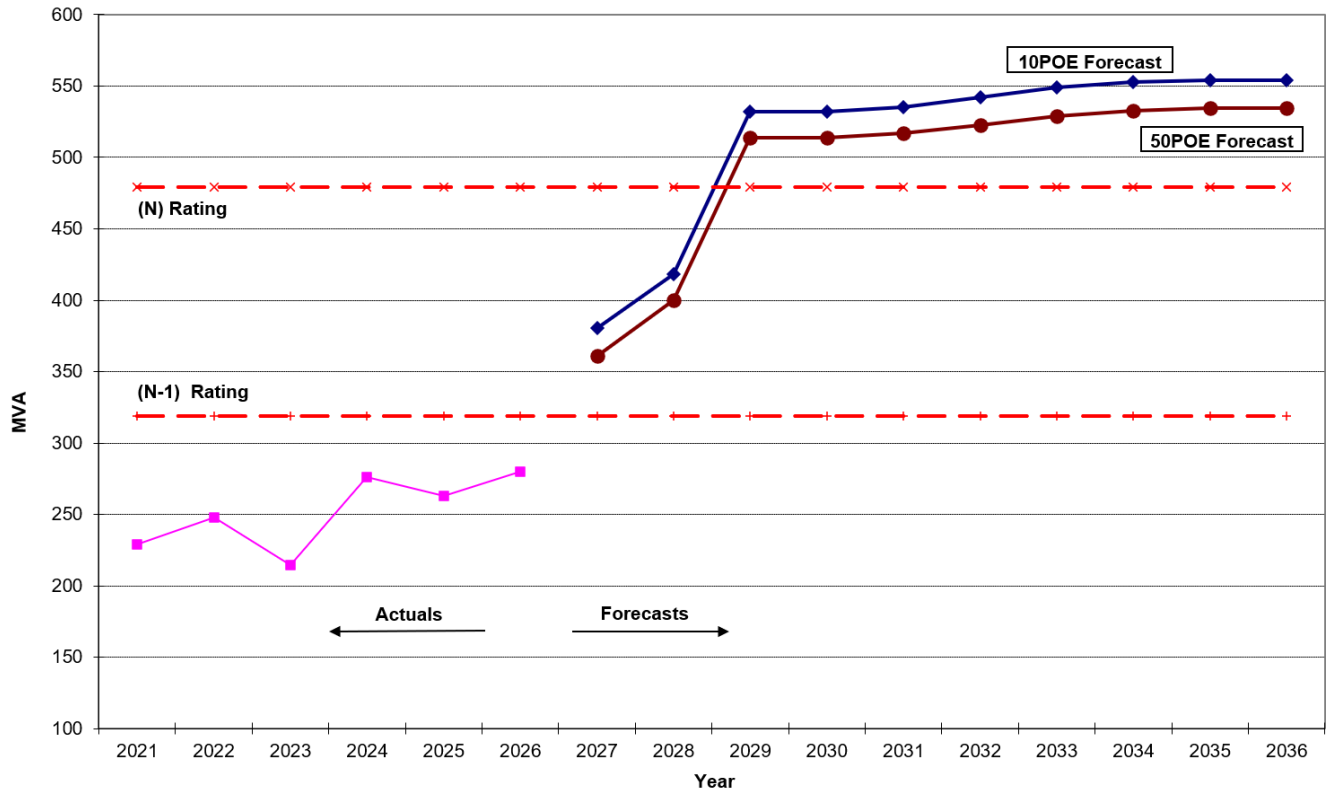
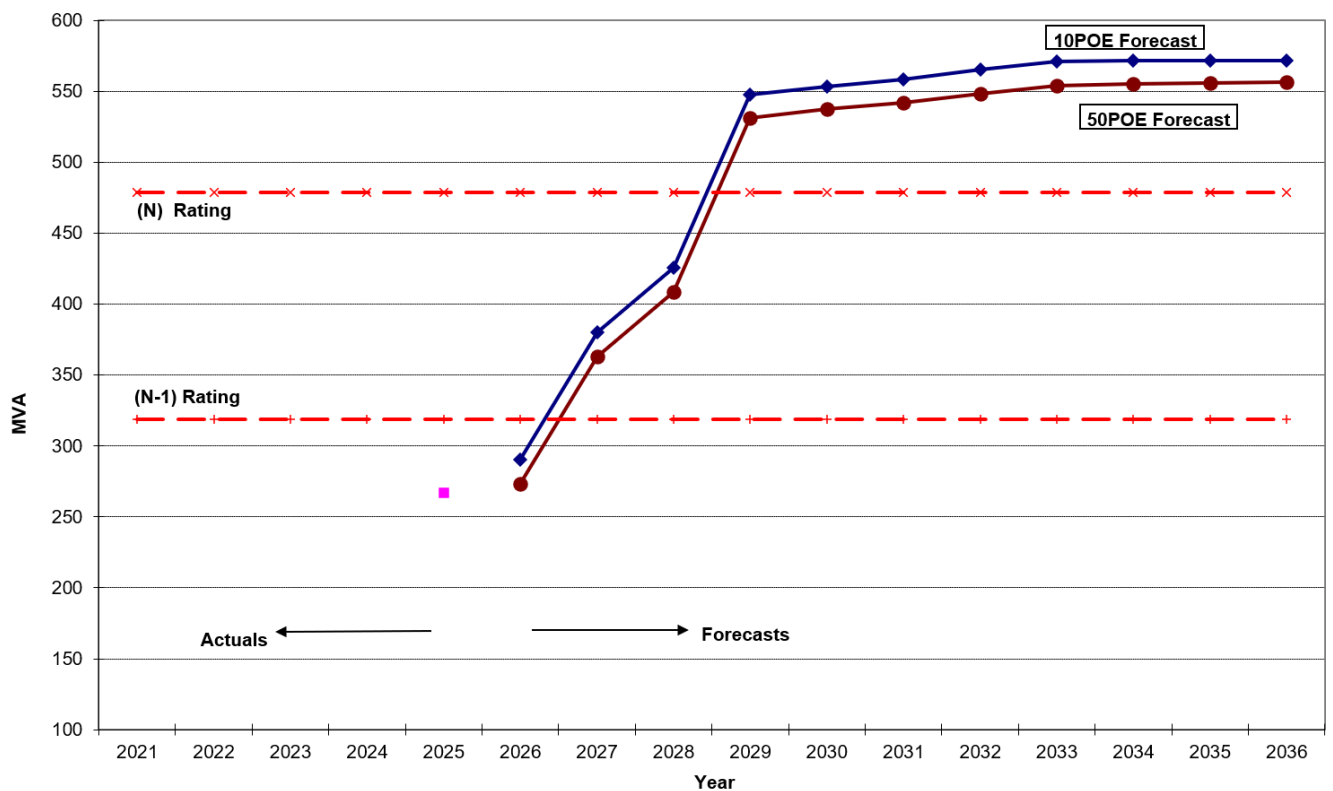


Figure 3-4 shows the POE10 and the POE50 forecasts maximum demand for the TTS34 group during winter periods relative to its capacity.

Figure 3-4: Winter period maximum demand forecasts for TTS34 group



3.2.3 Load transfer capability

There is the capacity to transfer 13.0 MVA of load away from the TTS12 group under system normal conditions (pre-contingent) and 0.7 MVA of load away from TTS12 to other terminal stations under single contingency conditions (post-contingent) via the distribution feeder network at peak demand in 2027.

For TTS34, transfers of 31.6 MVA pre-contingent and 23.3 MVA post-contingent via the distribution feeder network are possible at peak demand in 2027.

The transfer capacity for TTS12 and TTS34 is expected to be maintained for the entire ten-year forecast period.

3.2.4 Annual load profile

The load-duration curves for the TTS12 and TTS34 groups are shown in Figure 3-5 and Figure 3-6 for winter and summer periods.

Figure 3-5: Load-duration curve for TTS12 group at peak demand

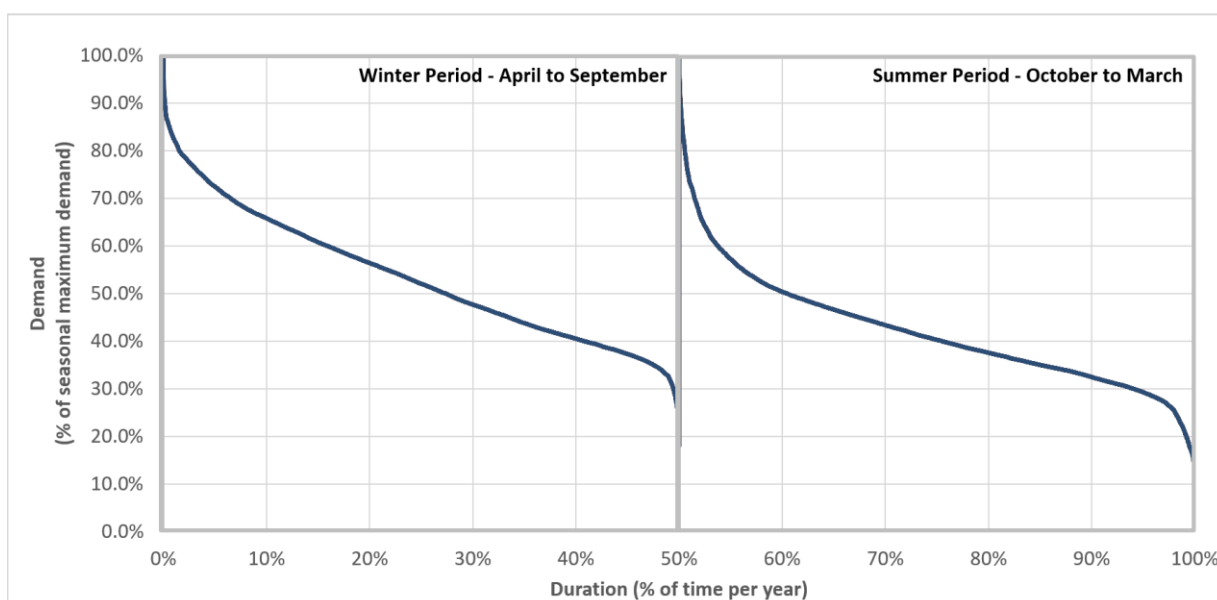
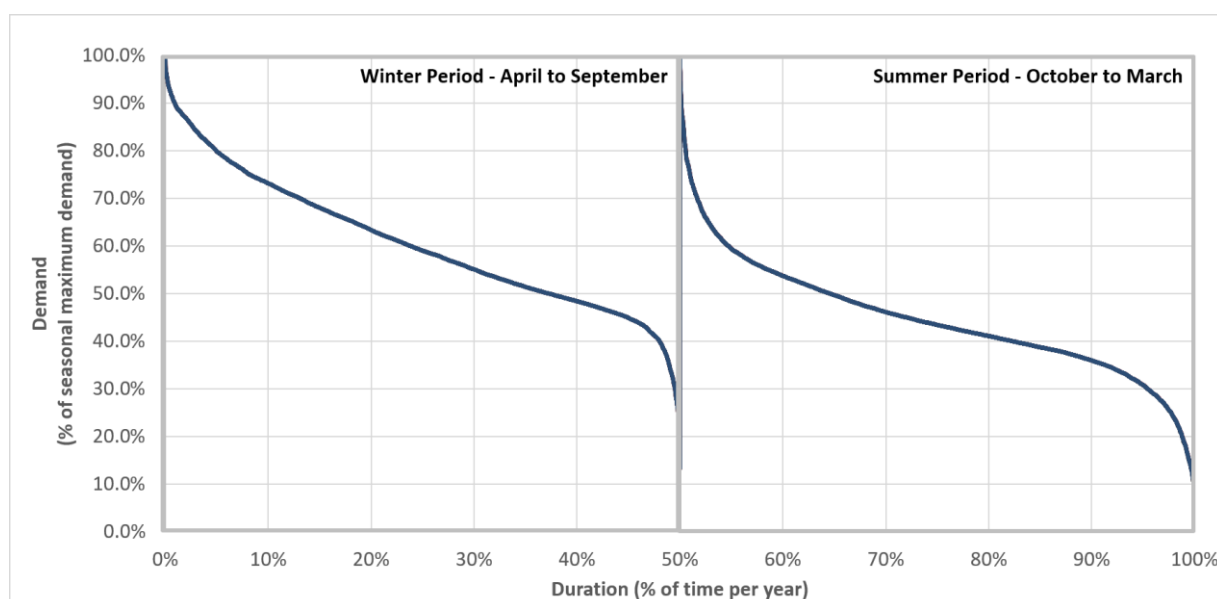


Figure 3-6: Load-duration curve for TTS34 group at peak demand



The shape of the curves is influenced by the coincidence of extreme ambient temperature on working weekdays and the number of times this occurs in any one year. They are also 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 2025, a total of 212 MW capacity of embedded generation is installed on the distribution systems connected to TTS. It consists of:

- 14.88 MW of large scale (>1 MW) embedded generation; and
- about 197 MW of small-commercial and residential rooftop solar PV (<1 MW), which includes 43 MW in the AusNet distribution system and 154 MW in the JEN distribution system.

The typical net daily load profiles at TTS12 and TTS34 groups during the summer peak are shown in Figure 3-7 and Figure 3-8 respectively.

Figure 3-7: Daily load profile for TTS12 group (summer peak demand)

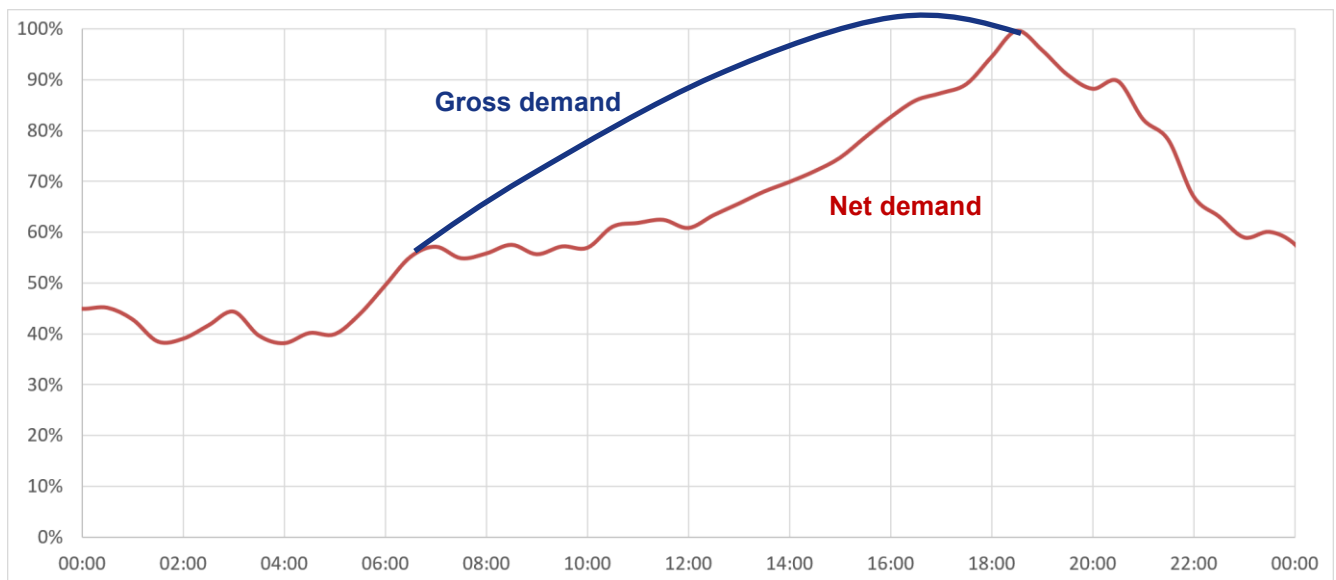
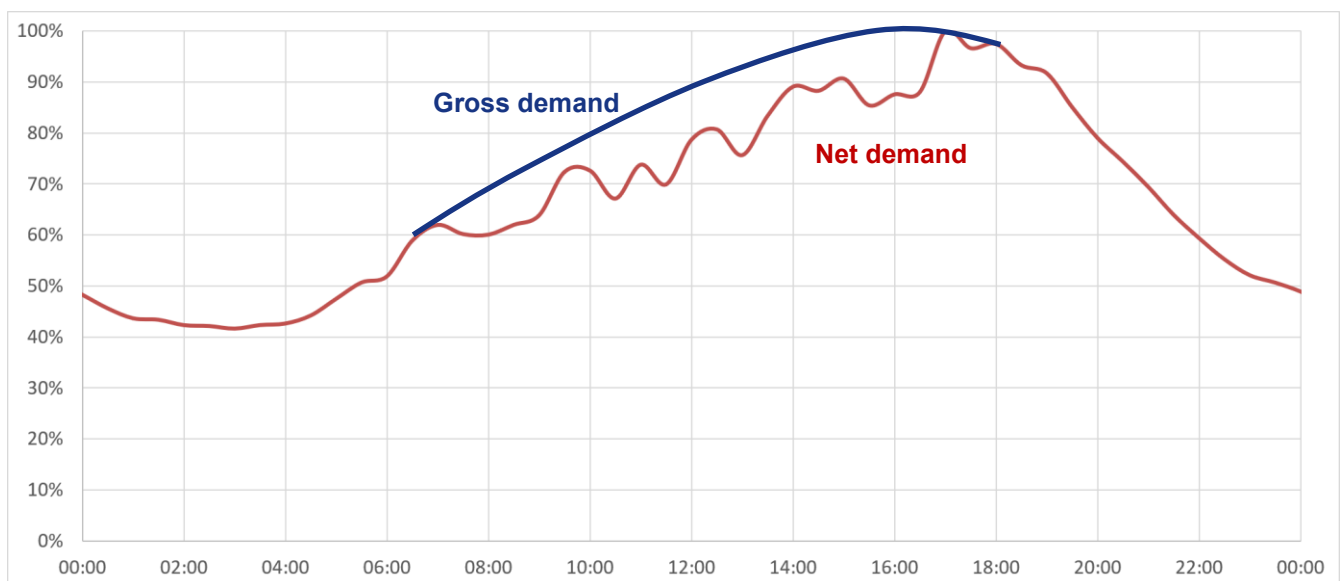


Figure 3-8: Daily load profile for TTS34 group (summer peak demand)



3.2.5 Network asset reliability

Table 3-4 provides a summary of the TTS 220/66 kV transformer reliability information²⁶ used in the EUE analysis.

Table 3-4: TTS 220/66 kV transformer reliability information

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, 1 month is required to return the transformer to service using a strategic spare (for 85% of failures), and 12 months for a new or repaired transformer (for 15% of failures), during which time the transformer is not available for service.
Expected transformer unavailability due to a major outage per transformer-year	0.221%	On average, each transformer would be expected to be unavailable due to major outages for $0.01 \times 2.65 \div 12 = 0.221\%$ of the time, or 19 hours per year.

²⁶ 2025 Transmission Connection Planning Report (TCPR), Appendix.

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**) as an input, which is an estimate of the value electricity consumers put on having a reliable electricity supply.

JEN and AusNet have applied locational VCR values based on the estimates in the Australian Energy Regulator's (**AER**) Values of Customer Reliability 2024 Review, adjusted by CPI in December 2025²⁷. Specifically, applying the AER's VCR estimates for different sectors (i.e., residential climate zone 6, commercial, industrial etc.) to terminal station level recent energy composition data, we have calculated the TTS VCR of \$41,306 per MWh as presented in Table 4-1.

Table 4-1: TTS value of customer reliability

Sector	AER VCR (\$/MWh, 2026)	Energy consumption	Weighted VCR (\$/MWh)
Residential	51,106	37.2%	19,011
Agricultural	23,098	0.1%	28
Commercial	35,700	50.2%	17,922
Industrial	34,766	12.5%	4,346
Composite		100%	41,306

4.1.2 Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. We intend to use the commercial discount rate in AEMO's 2025 inputs, assumptions and scenarios report (**IASR**)²⁸ being 7.0 per cent.

The discount rate used in this RIT-T for the low bound sensitivity test is a regulatory discount rate of 4.69 per cent. For the high bound sensitivity test we use a 10.0 per cent discount rate consistent with the IASR.

²⁷ [Values of Customer Reliability](#), Australian Energy Regulator (AER), 2025.

²⁸ [2025 Inputs, Assumptions and Scenarios Report](#), Table 31, Australian Energy Market Operator (AEMO), 2025.

4.1.3 Assessment period

We intend to undertake the NPV analysis over a ten-year period, from 2027 to 2036. We consider that the length of this assessment period takes into account the size, complexity and minimum 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 demand growth in the supply area intended to be addressed by the credible options in this RIT-T.

The relatively modest time period proposed to be used for the assessment mitigates the uncertainty in the demand forecast, and acknowledges that a further augmentation of TTS may be needed in future if the major customer and data-centre loads reach their full potential, in which case another RIT-T will be initiated.

4.2 Approach to estimating option costs

The costs for each option have been calculated by AusNet Transmission Group, JEN and AusNet distribution's cost estimation teams based on recent similar project costs and scope, net of customer contributions. 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 2026 dollars based on the information available at the time of preparing this report. Overheads and financing charges comprise approximately 10.7 per cent of the total costs, and contingency risk comprises 5.8 per cent.

Social license costs are included commensurate with the nature, scale and location of the proposed options. The cost estimates include allowances for community engagement, planning and environmental approvals, cultural heritage assessments, landholder engagement, and any measures needed to address community impacts. These costs are built into the relevant project cost estimates and have been based on the scale and nature of each option and experience from similar projects.

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 of the capital cost per annum 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 that²⁹:

- 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.

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 next stage of the RIT-T process, having regard to any submissions to the PSCR including from non-network option proponents.

²⁹ AER, Regulatory Investment Test for Transmission, November 2024, paragraphs 7 and 11.

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 or changes in voluntary load curtailment;
- **Changes in costs for parties** other than JEN and AusNet, as there is no other known investment, either generation or transmission, that will be affected by any option considered;
- **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 SF₆ emissions from high-voltage switchgear³⁰;
- **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. 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 options are not expected to impact on the demand for and supply of ancillary services; and
- **Competition benefits**, as there is no competing generation affected by the limitations and risks being addressed by the options considered for this RIT-T.

³⁰ We have undertaken a preliminary assessment of whether the network options could materially change Australia's greenhouse gas emissions. At this stage, Options 2 and 3 are not expected to cause a material change in emissions compared to the base case and, therefore, greenhouse gas emissions are not expected to be a material market benefit for these options. This assessment will be reviewed in the PADR as the analysis is refined. Any non-network or hybrid options received through consultation will be assessed separately. Where greenhouse gas emissions are found to be material or could affect the preferred option, the benefit will be quantified using the applicable Value of Emissions Reduction (VER).

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

The NER and the AER's RIT-T Application Guidelines require that a PSCR include the technical characteristics of the identified need that a non-network or SAPS option would be required to deliver³¹. This chapter outlines the technical characteristics of the network support services required to alleviate the forecast capacity limitations at TTS 66 kV.

5.1 Performance requirements

Initial analysis by JEN and AusNet indicates that Option 2 may be the preferred *network* option, subject to completion of the RIT-T assessment process. This option has an annualised cost of \$6.1 million (real, 2026) 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 2-5, the EUE risk exceeds the annualised cost of the preferred network option in 2029, which represents the indicative year 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 AusNet are seeking from a full non-network or SAPS option by 2029 at TTS is 37 MW pre-contingent³² and 160 MW post-contingent³³, preferably on the TTS34 66 kV bus group which services areas around Broadmeadows, Bundoora, Campbellfield, Coburg, Coolaroo, Lalor, Reservoir and Thomastown³⁴.

This need would increase in the following years according to Table 2-3. Lower levels of support may be acceptable if combined with other network or non-network solutions, as described above.

The magnitude and duration for TTS network support services required under various seasonal, loading and network operating conditions (considering the likelihood of those conditions), is detailed in Table 2-3, with the indicative time of day requirements shown in Figure 3-8.

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 (or standby) 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 AusNet as soon as possible. A detailed proposal including the information listed below should be submitted by the requested date. Details required include:

³¹ NER, clause 5.16.4(b)(3); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.

³² Load at risk above 'N'.

³³ Sum of the Load at risk above 'N-1' and the Load at risk above 'N'.

³⁴ Network support services provided in the other areas of TTS (served by the TTS12 group) could be considered, however it is likely that some network investment would be required to rebalance the load across the two bus groups.

- 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)
 - 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 AusNet'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. [AusNet Industry Engagement Strategy](#).

6. Description of potential credible options

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

- **Option 1** – Non-network or SAPS solution;
- **Option 2** – Install two additional transformers at TTS (B6 & B7); and
- **Option 3** – Establish a new two-transformer Somerton Terminal Station (SOTS).

The potential credible options are assessed against a Do-nothing base case.

All of the *network* options would increase the thermal capacity of TTS. Table 6-1 below summarises the new thermal capacity ratings that would result from the two network options, compared to the base case in Table 3-1 in which no investment is undertaken.

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

Rating	Option 2		Option 3		
	TTS123 group	TTS467 group	TTS12 group	TTS34 group	SOTS
Summer (N)	503	479	335	479	530
Summer (N-1)	503	479	335	319	265
Winter (N)	503	479	335	479	586
Winter (N-1)	503	479	335	319	293

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 AusNet consider that all options reduce EUE to a level consistent with the identified need for this RIT-T.

6.1 Do-nothing

"Do-nothing" involves continuing to supply customers serviced by TTS 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 2-5, the total combined value of the EUE risk associated with Do-nothing is forecast to increase from \$1.02 million in 2027 to \$43.6 million in 2029, to \$104 million by 2036 (real, 2026).

In the context of this RIT-T, Do-nothing 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. Do-nothing is assumed not to involve any material incremental costs relative to the credible options. Routine operating and maintenance costs associated with the existing assets are expected to be incurred under both the base case and the credible options and are therefore not expected to materially affect the assessment.

6.2 Option 1 - 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 TTS to reduce the net maximum demand on TTS (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 embedded (or standby) storage and/or generation resources.

Chapter 5 of this PSCR 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 AusNet 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 or hybrid options arising from submissions to this PSCR.

6.3 Option 2 – Install two additional transformers at TTS (B6 & B7)

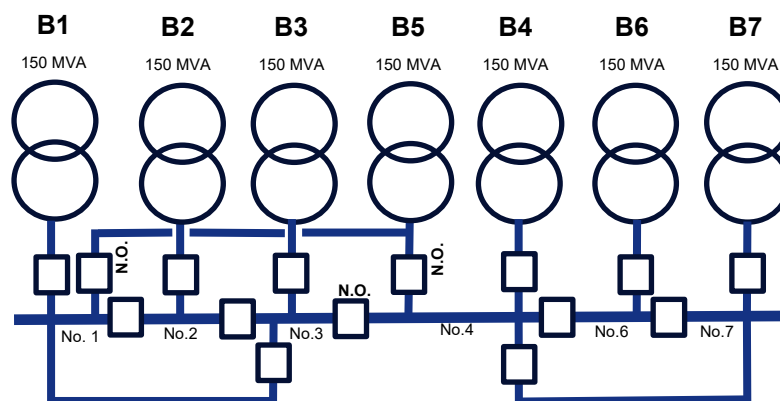
This option involves adding two new 220/66 kV 150 MVA transformers to TTS (designated B6 and B7), two new 66 kV buses (designated No.6 and No.7), and reconfiguring the existing 66 kV bus groups from TTS12 and TTS34, to new TTS123 and TTS467 bus groups.

The B5 transformer will perform the function of an unloaded hot standby for TTS, being able to auto-close onto either of the two new 66 kV bus groups, to pick up load during a single contingency condition.

As part of this option, 66 kV feeder bays will be rearranged at TTS to balance loading across the two new bus groups.

A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 6-1.

Figure 6-1: Install two additional transformers at TTS (B6 & B7) 66 kV simplified single line diagram (Option 2)



The high-level scope of work required for this option includes:

- Two 220 kV, 4000 A; 40 kA circuit breaker bays.
- Two B transformers (150 MVA; 220/66/11 kV) - designated B6 and B7 (with 66 kV neutral reactors).
- 220 kV bus work, underground cable and connections from the new 220 kV bays to the new transformers (i.e., B6 to 220 kV Bus No. 3, B7 to 220 kV Bus No.1).
- Two 66 kV, 3150 A; 31.5 kA circuit breakers for B6 and B7 transformers.
- Two 66 kV, 3150 A; 31.5 kA circuit breakers for the 4-6 and 6-7 bus ties.
- 66 kV bus work, cable, conductors and connections to connect B6 and B7 transformers to two new 66 kV buses (No.6 and No.7 respectively), and to rearrange the existing 66 kV bus groups from TTS12 and TTS34, to new TTS123 and TTS467 ring bus groups, including relocating the B5 connection from the 66 kV Bus No.3 to No.4 - as shown in Figure 6-1.
- Three 66 kV, 3150 A; 31.5 kA feeder circuit breaker bays.

- 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 (bundling, 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 TTS including setting, configuration and control scheme modifications, with feeder unit protection relays that match 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 TTS site (if required).

The estimated capital cost of this network option is \$75 million (real, 2026), with ongoing operations and maintenance costs of \$0.8 million per annum.

This option has an estimated construction period of two years.

The annualised cost of this option is \$6.1 million.

Considering the annualised cost and the construction lead time, the optimal timing of this option based on the forecast weighted value of EUE at TTS (as set out in Table 2-5) is by 2029.

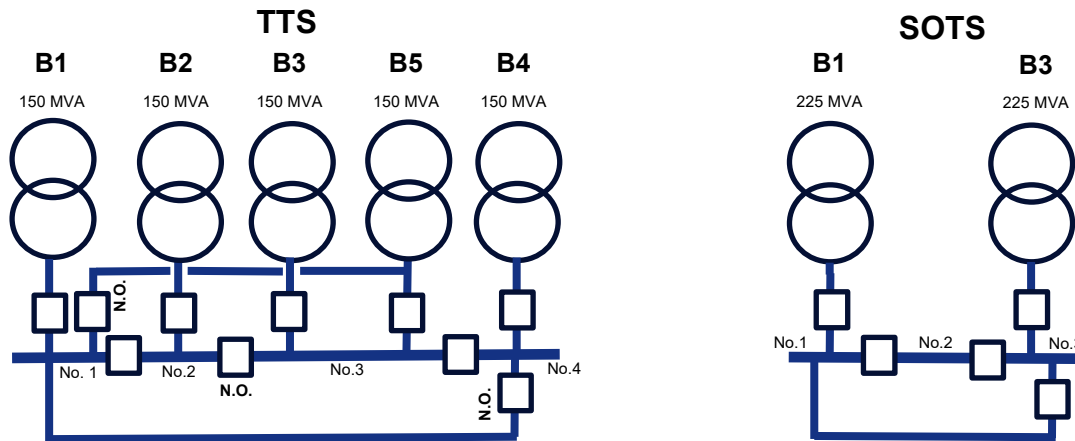
This option is not likely to have a material inter-network impact. This option would consider relevant for this RIT-T, only those market benefits contemplated by Clause 5.15A.2 of the NER relating to changes in involuntary load reduction.

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

6.4 Option 3 – Establish a new two-transformer Somerton Terminal Station (SOTS)

This option involves establishing a new 500/220/66 kV terminal station in the Somerton area (designated SOTS) with two new 220/66 kV 225 MVA transformers (designated B1 and B3) and two new 500/220 kV 1,000 MVA transformers (designated A1 and A2). A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 6-2.

Figure 6-2: Establish a new two-transformer SOTS simplified single line diagram (Option 3)



The high-level scope of work required for this option includes:

- Two 500 kV buses.
- Four 500 kV circuit breakers.
- Cut into and connect in the existing KTS-SMTS 550 kV line into two line bays.
- Two A transformers (1,000 MVA; 500/220 kV) - A1 and A2.
- Two 220 kV buses.
- Two 220 kV, 4000 A; 40 kA circuit breaker bays.
- Two B transformers (225 MVA; 220/66/11 kV) - designated B1 and B3 (with 66 kV neutral reactors).
- Two 66 kV, 3150 A; 31.5 kA circuit breakers for B1 and B3 transformers.
- Three 66 kV, 3150 A; 31.5 kA circuit breakers for the 1-2, 2-3 and 3-1 bus ties.
- 66 kV bus work, cable, conductors and connections to connect B1 and B3 transformers to new 66 kV buses (No.1 and No.3 respectively, and No.2 bus) - as shown in Figure 6-2.
- Three new 66 kV, 3150 A; 31.5 kA feeder circuit breaker bays (one on each bus).
- 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 (bundling, 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 remote end systems including setting, configuration and control schemes that match 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 and around the SOTS site.

The estimated capital cost of this network option is \$250 million (real, 2026), with ongoing operations and maintenance costs of \$1.3 million per annum.

This option has an estimated construction period of three years.

The annualised cost of this option is \$19.7 million.

Considering the annualised cost and the construction lead time, the optimal timing of this option based on the forecast weighted value of EUE at TTS (as set out in Table 2-5) is by 2030.

This option is not likely to have a material inter-network impact. This option would consider relevant for this RIT-T, only those market benefits contemplated by Clause 5.15A.2 of the NER relating to changes in involuntary load reduction.

Social licence considerations are expected to be more significant for this option than for the other network options due to the need to establish a new terminal station, construct 66 kV sub-transmission lines within existing road reserves and new easements, and undertake associated land, planning and environmental approvals. While only existing transmission line cut-ins are expected to be required, the option may affect a broader range of stakeholders, including landowners, local communities, councils and other interested parties. Accordingly, community and stakeholder engagement, as well as environmental, cultural heritage, planning and land access activities, are expected to form an important part of option development and delivery. Associated costs have been incorporated into the option cost estimate.

7. Submissions and next steps

7.1 Request for submissions

JEN and AusNet invite written proposals for alternative options, submissions and enquiries on the matters set out in this PSCR from interested stakeholders.

All submissions and enquiries should be titled “**Thomastown Supply Area RIT-T**” and directed to both:

George Tziokas (JEN)

Grid Planning and Reliability Manager

PlanningRequest@jemena.com.au

and

Ali Kharrazi (AusNet)

Manager, Sub-Transmission Network Planning

ritconsultations@ausnetservices.com.au

The consultation on this PSCR is open for 12 weeks, consistent with the NER requirements³⁵. Submissions are due on or before **22 December 2026**.

Submissions will be published on the Australian Energy Market Operator (**AEMO**), JEN and AusNet 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 AusNet 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 AusNet intend on publishing the PADR in the **first quarter of 2027**.

³⁵ 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 253.

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