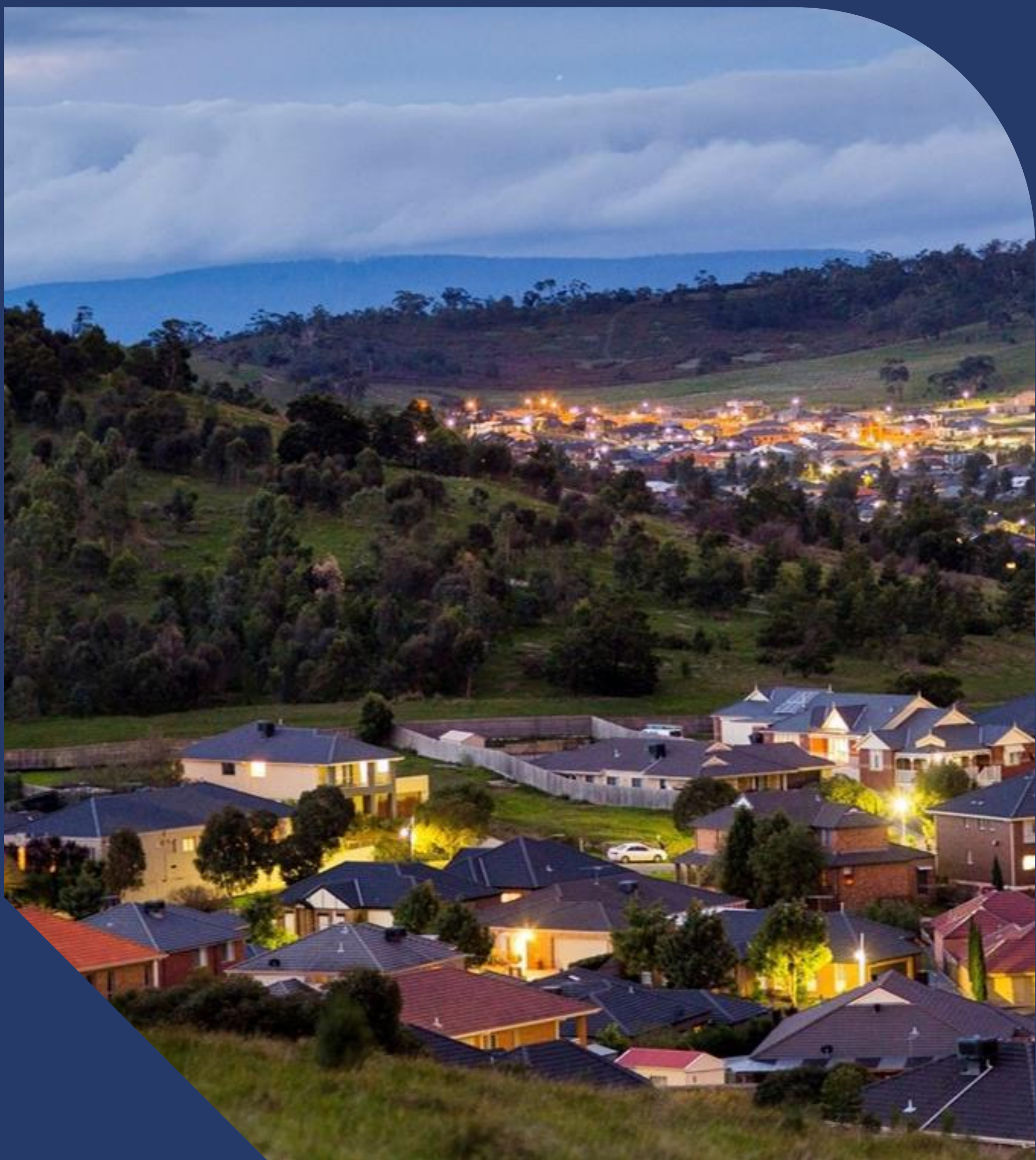
Maintaining supply reliability in the South Morang supply area

RIT-T Project Specification Consultation Report

Friday, 27 June 2025



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Important notice

Purpose

AusNet Electricity Services Pty Ltd (AusNet) and Jemena Electricity Network (JEN) have prepared this project specification consultation report (PSCR) in accordance with clause 5.16.4 of the National Electricity Rules (NER). This PSCR is the first stage of the South Morang Supply Area Regulatory Investment Test for Transmission (RIT-T) consultation process, relating to maintaining supply reliability within the South Morang supply area.

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Executive summary

AusNet Electricity Services Pty Ltd (AusNet) and Jemena Electricity Network (JEN) are regulated Victorian Distribution Network Service Providers (DNSPs) that supply electricity distribution services to more than 809,000 and 384,000 customers, respectively. AusNet's electricity distribution network services eastern regional Victoria and the outer northern and eastern Melbourne metropolitan area. JEN's electricity distribution network services Melbourne's northern and western greater metropolitan area.

As expected by our customers and required by the various regulatory instruments that we operate under, AusNet and JEN 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. In Victoria, the DNSPs have responsibility for planning and directing augmentation of the transmission connection assets that connect their distribution systems to the Victorian shared transmission system. This report relates to proposed investment on the transmission connection assets at South Morang Terminal Station (SMTS) and as such, is subject to a regulatory investment test for transmission (RIT-T). SMTS supplies electricity to parts of the AusNet (the lead proponent of this RIT-T) and JEN electricity distribution networks.

This project specification consultation report (PSCR) is stage one of the South Morang Supply Area RIT-T consultation process and has been jointly prepared by AusNet and JEN in accordance with the requirements of clause 5.16 of the National Electricity Rules (NER)[1] and section 4.2 of the RIT-T Application Guidelines[2]. This report 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 maintain electricity supply reliability and reduce expected unserved energy (EUE) for those customers supplied from SMTS.

SMTS is owned and operated by AusNet Transmission Group and is located in South Morang in Melbourne's north eastern suburbs in Victoria. It serves as the main transmission connection point for distribution of electricity to customers to those parts within the AusNet and JEN distribution service areas incorporating the South Morang supply area.

SMTS supplies electricity to more than 155,159 customers[3], with residential customers consuming 49.1 per cent of the total annual energy supplied from SMTS, closely followed by commercial customers at 36.4 per cent. The geographic coverage of the area supplied by the transmission connection assets at SMTS spans from Seymour, Kilmore, Kalkallo, Kinglake and Rubicon in the north to Mill Park in the south, and from Doreen and Mernda in the east to Somerton and Craigieburn in the west.

Electricity demand in the SMTS service area has been amongst the fastest growing regions in Victoria and SMTS is reaching its full capacity in the near future. The summer peak demand at SMTS increased by 133 MVA between 2011-12 and 2023-24, equivalent to an average annual growth rate of 13 MVA or 6.1 per cent. In 2023-24 the summer maximum demand reached 389 MVA, which is the historical maximum for this terminal station.

SMTS currently has two 220/66 kV 225 MVA transformers and the summer cyclic rating of SMTS with all plant in service is 530 MVA at 35°C and 500 MVA at 40°C. This rating is expected to be exceeded in 2028-29 for the POE10, and in 2031-32 for the POE50[4]. The summer cyclic rating of SMTS with one of its two transformers out of service, reduces to 265 MVA at 35°C and 250 MVA at 40°C and this rating is expected to be exceeded every year from now.

The maximum demand growth in the SMTS supply area is primarily due to the following:

- staged development of residential estates and other residential subdivisions; commercial developments, such as shopping centres, childcare centres, schools, medical centres and retail hubs, associated with new large residential developments and large customer loads; and
- electrification of gas and transport sectors of society, associated with the energy transition.

Due to the strong demand growth in the area and the high utilisation of SMTS at maximum demand, the level of EUE resulting from capacity limitations at SMTS is forecast to grow, deteriorating supply reliability for our customers.

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[1] National Electricity Rules, version 230, Australian Energy Market Commission (AEMC), 2025.
[2] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.
[3] 37,268 JEN customers, and 117,891 AusNet customers.
[4] To identify overload timing, the 35°C cyclic rating is compared against the POE50 forecast demand, and the 40°C cyclic rating is compared against the POE10 forecast demand.

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 net economic benefit. The need for this investment has been flagged in the 2024 Transmission Connection Planning Report (TCPR)[5], published jointly by the Victorian DNSPs.

Potential credible options

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

- Option 1 - Do Nothing;
- Option 2 - Non-network or SAPS solution;
- Option 3 - Install third 220/66 kV transformer at SMTS;
- Option 4 - Install third and fourth 220/66 kV transformers at SMTS;
- Option 5 - Establish two new 22 kV feeders to offload SMTS (followed by Option 3);
- Option 6 - Establish a new 220/66 kV Donnybrook terminal station (DBTS).

Options 5 and 6 are considered in this PSCR but unlikely to be progressed on the basis that they are either not technically credible, cost prohibitive or cannot meet the identified need in time.

Initial analysis by AusNet and JEN has identified that Option 3 is likely to be the preferred *network* option. This assessment will be confirmed through the RIT-T process.

Submissions

AusNet and JEN invite written submissions and enquires on the matters set out in this PSCR from interested stakeholders. All submissions and enquiries should be titled "***South Morang Supply Area 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 30th September 2025.

Submissions may be published on the Australian Energy Market Operator (AEMO), AusNet and JEN 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 PCSR consultation period, AusNet and JEN 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 detailed description of the methodologies used in quantifying costs and material market benefit;
- 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.

AusNet and JEN intend on publishing the PADR in the fourth quarter of 2025.

[5] Transmission Connection Planning Report, Victorian Distribution Network Service Providers, 2024.
[6] NER, clause 5.16.4(g).

1. Introduction

AusNet Electricity Services Pty Ltd (AusNet) and Jemena Electricity Network (JEN) are regulated Victorian Distribution Network Service Providers (DNSPs) that supply electricity distribution services to more than 809,000 and 384,000 customers, respectively. AusNet's electricity distribution network services eastern regional Victoria and the outer northern and eastern Melbourne metropolitan area. JEN's electricity distribution network services Melbourne's northern and western greater metropolitan area.

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 (the preferred option). The process follows the requirements in clauses 5.15A and 5.16 of the National Electricity Rules (NER)[7] and is summarised in Figure 16 of Appendix A.

The RIT-T applies in circumstances where a network limitation (an identified need) exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than the threshold of $8 million[8].

AusNet and JEN are undertaking this RIT-T to evaluate options to maintain reliability of supply in the South Morang 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, from the transmission connection assets at South Morang Terminal Station (SMTS). The capital cost of credible options (including the proposed preferred network option) to address this identified need within the South Morang supply area is above the RIT-T cost threshold and so has triggered the requirement for a RIT-T.

This project specification consultation report (PSCR) is the first stage of the South Morang Supply Area RIT-T consultation process and has been jointly prepared by AusNet and JEN in accordance with section 4.2 of the RIT-T Application Guidelines[9] and the requirements of clause 5.16 of the NER, 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 need for this investment has been flagged in the 2024 Transmission Connection Planning Report (TCPR)[10], published jointly by the Victorian DNSPs.

The structure of this PSCR is as follows:

- **Chapter 2** describes the identified need that AusNet and JEN are seeking to address, which is in relation to the SMTS capacity limitations;
- **Chapter 3** outlines the assumptions made in identifying the need;
- **Chapter 4** outlines the technical characteristics of the identified need that a non-network option would be required to deliver to address the identified need;
- **Chapter 5** describes the credible options that AusNet and JEN consider could potentially address the identified need;
- **Chapter 6** outlines the proposed assessment methodology for this RIT-T; and
- **Chapter 7** invites interested stakeholders to make a formal written submission on this PSCR.

[7] National Electricity Rules, version 230, 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, Victorian Distribution Network Service Providers, 2024.

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 need. This chapter addresses this requirement.[11] This chapter discusses the role of South Morang Terminal Station (SMTS) 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) for the status-quo is also presented.

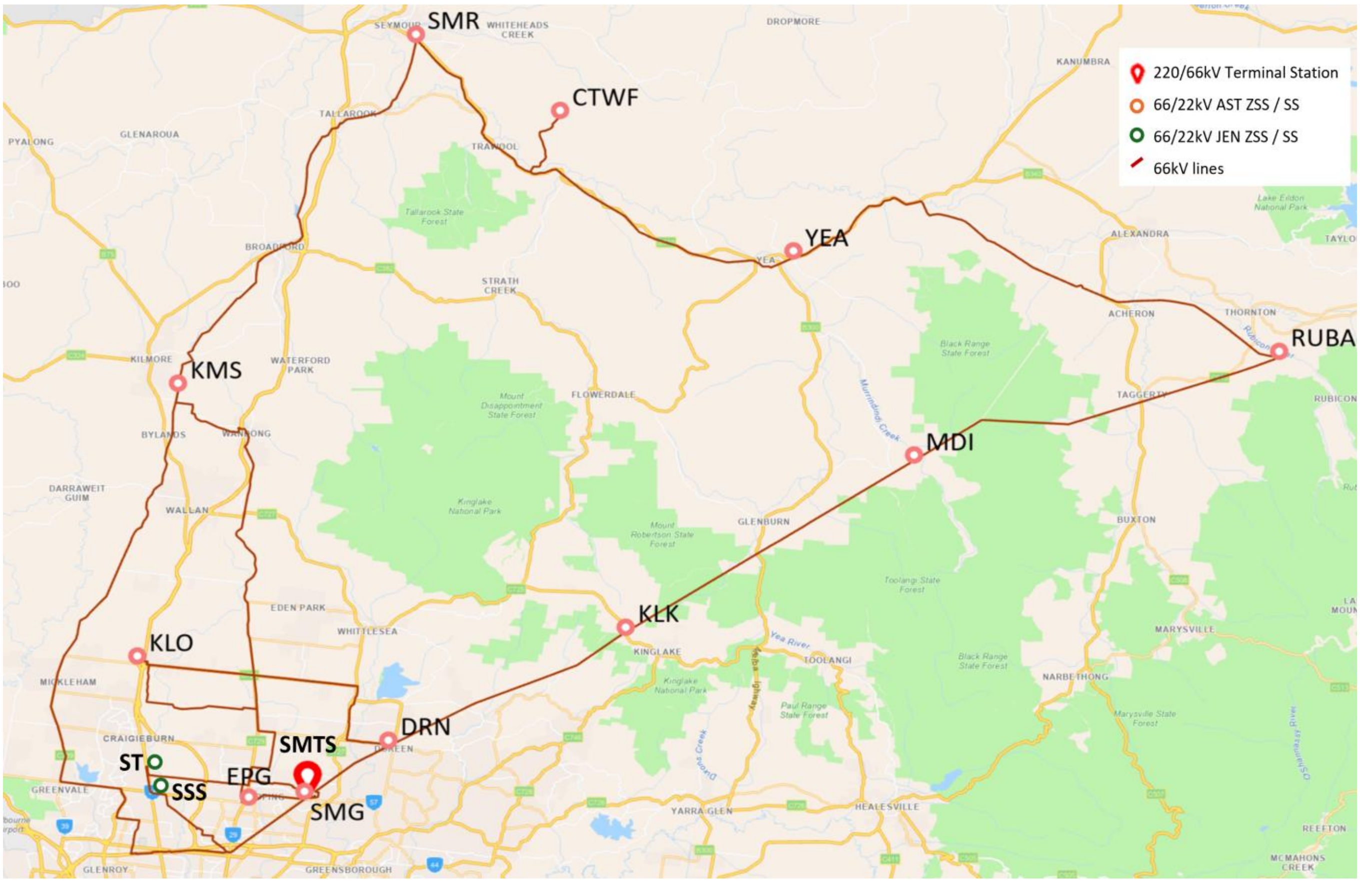
2.1. South Morang supply area

SMTS is the only terminal station that supplies the South Morang supply area. SMTS was originally established with two 220/66 kV 225 MVA transformers as a new terminal station in 2008 to reinforce the electricity network for the South Morang supply area.

The geographic coverage of the South Morang supply area serviced by SMTS spans from Seymour, Kilmore, Kalkallo, Kinglake and Rubicon in the north to Mill Park in the south, and from Doreen and Mernda in the east to Somerton and Craigieburn in the west. The electricity distribution networks for this area are the responsibility of both AusNet (72%) and JEN (28%), based on annual net energy consumption.

Figure 1 shows the regional portion of the South Morang supply area, with 66 kV sub-transmission lines shown in red.

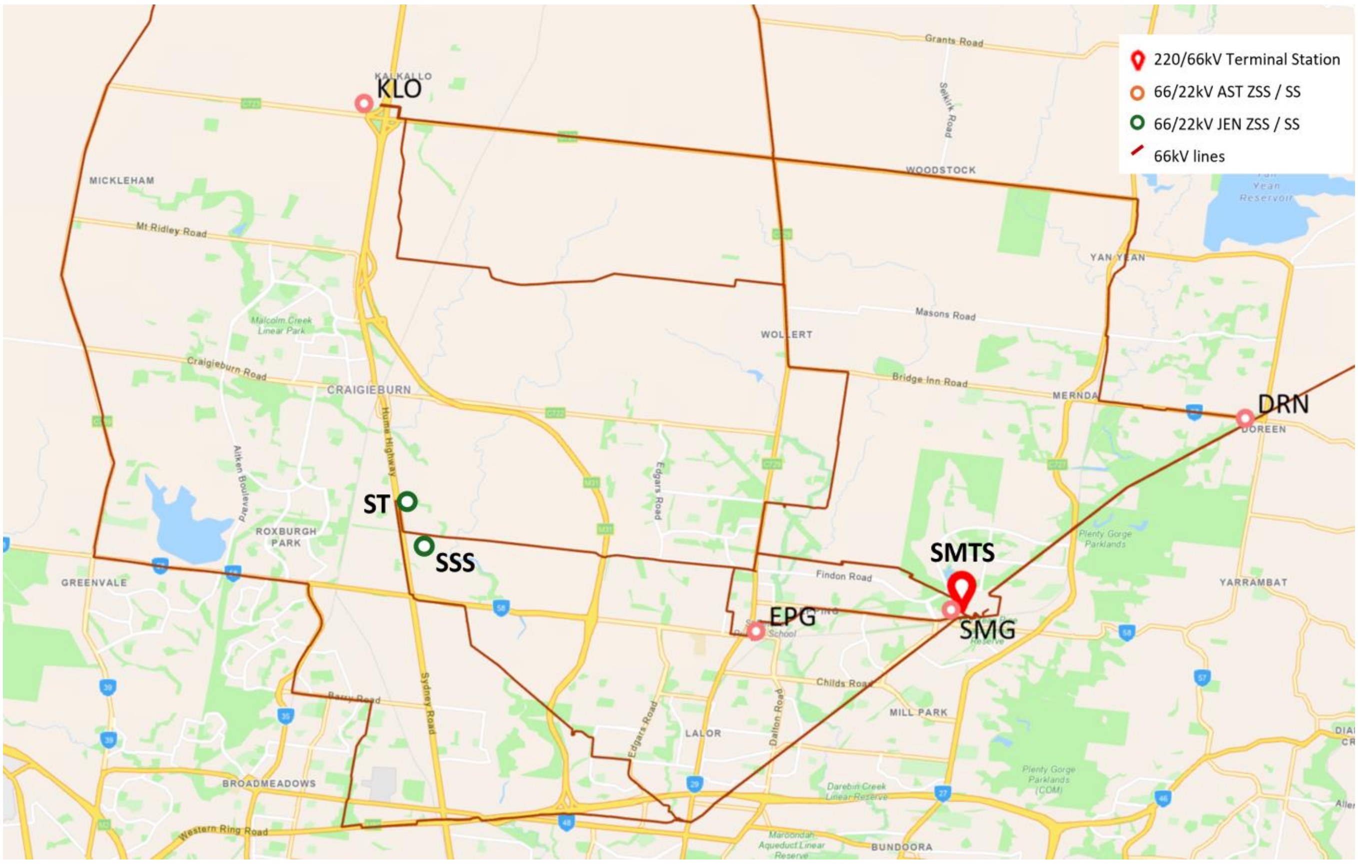
Figure 1: South Morang terminal station (SMTS) supply area with sub-transmission lines - regional



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

Figure 2 shows the location of SMTS within the metropolitan portion of the South Morang supply area, with 66 kV sub-transmission lines shown in red.

Figure 2: South Morang terminal station (SMTS) supply area with sub-transmission lines - metropolitan



2.1.1. Customer demand for electricity

More than 155,159 customers[12] rely on SMTS for their electricity supply. Growth in customer numbers in the supply area has been substantial. Customer number growth has averaged 7,100 additional customers per annum since 2019, an average annual increase of 5.8 per cent[13].

Residential customers consume 49.1 per cent of the total annual energy supplied from SMTS as listed in Table 1. This is closely followed by commercial customers, consuming 36.4 per cent of the total annual energy supplied.

[12] Total customer numbers in 2023-24 were 37,268 JEN customers, and 117,891 AusNet customers.
[13] Total customer numbers in 2019 were 24,751 JEN customers, and 98,427 AusNet customers.

Table 1: SMTS net energy consumption composition

CUSTOMER TYPE	SHARE OF CONSUMPTION (%)
Residential	49.1
Commercial	36.4
Industrial	12.1
Agricultural	2.4
Total	100

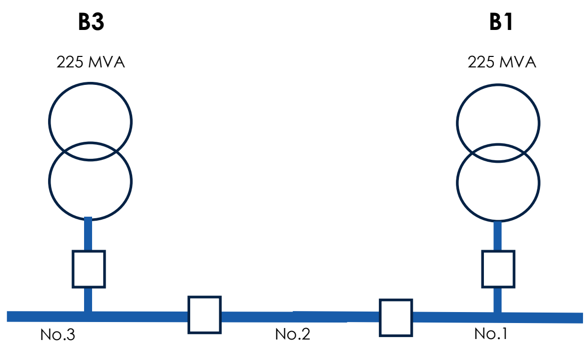
SMTS is a summer-peaking terminal station. Electricity demand on SMTS has been amongst the fastest growing in Victoria, and SMTS is reaching its full capacity in the near future. The summer peak demand at SMTS increased by 133 MVA between 2011-12 and 2023-24, equivalent to an average annual growth rate of 13 MVA or 6.1 per cent. In 2023-24 the summer maximum demand reached 389 MVA, which is the historical maximum for this terminal station.

The 10 per cent and 50 per cent probability of exceedance (POE) forecast summer maximum demands in 2025-26 are expected to reach 426 MVA and 394 MVA respectively. Section 3.2.2 provides an overview of the maximum demand forecasts that underpin the identified need.

2.1.2. Electricity network servicing the supply area

SMTS currently has two parallel 220/66 kV 225 MVA transformers and three 66 kV buses. A simplified single line diagram of SMTS is provided in Figure 3. The summer cyclic rating of SMTS with all plant in service is 530 MVA at 35°C and 500 MVA at 40°C. This rating is expected to be exceeded in 2028-29 for the POE10, and in 2031-32 for the POE50[14]. The summer cyclic rating of SMTS with one of its two transformers out of service, reduces to 265 MVA at 35°C and 250 MVA at 40°C and this rating is expected to be exceeded every year from now.

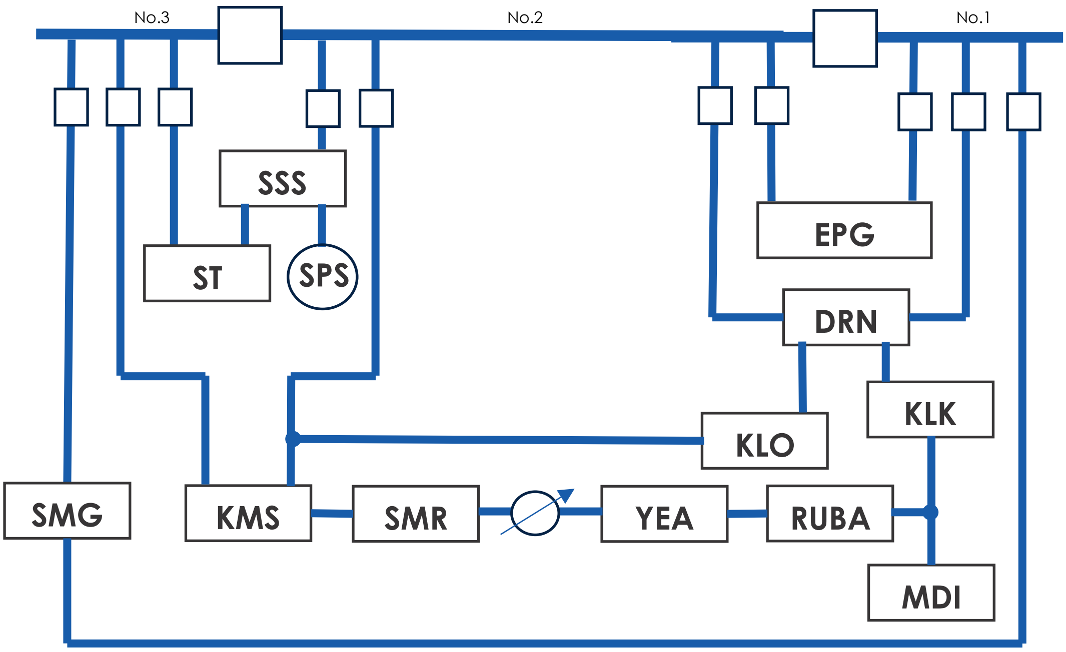
Figure 3: SMTS existing transmission connection assets single line diagram



SMTS has ten 66 kV sub-transmission line exits supplying ten AusNet zone substations, Epping (EPG), Doreen (DRN), Kalkallo (KLO), Kinglake (KLK), Murrindindi (MDI), Rubicon (RUBA), Seymour (SMR), Kilmore South (KMS) and South Morang (SMG), one JEN zone substation, Somerton (ST), and Somerton power station (SPS) via a switching station (SSS). This is shown schematically in Figure 4.

[14] To identify overload timing, the 35°C cyclic rating is compared against the POE50 forecast demand, and the 40°C cyclic rating is compared against the POE10 forecast demand.

Figure 4: SMTS existing sub-transmission network schematic diagram



As of 2024, about 180 MW of rooftop solar PV is installed on the AusNet distribution system and about 68 MW of rooftop solar PV is installed on the JEN distribution system connected to SMTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW. A total of 247.2 MW capacity of large-scale embedded generation is installed on the AusNet and JEN sub-transmission and distribution systems connected to SMTS.

Table 2: SMTS embedded generation

SITE NAME	TYPE	CAPACITY (MW)
Somerton Power Station	Gas	150
Cherry Tree Wind Farm	Wind	57.5
Wollert Power Station	Landfill gas	7.7
Rubicon Power Station	Hydroelectric	14.6
Distributed Solar PV (JEN)	Solar	68
Distributed Solar PV (AusNet)	Solar	180

2.2. Identified need

There is forecast to be insufficient capacity to supply the forecast maximum demand at SMTS with the existing transmission connection assets that are in place under system normal conditions by 2028-29 based on POE10 forecasts, or 2031-32 based on POE50 forecasts. Under single contingency conditions, there is already load at risk based on POE50 demand forecasts. The amount of load at risk will increase going forward and this is likely to lead to a significant deterioration in supply reliability for customers within the South Morang supply area, and inhibit the connection of new customers.

The maximum demand growth in the SMTS supply area is primarily due to the following:

- staged development of residential estates and other residential subdivisions; commercial developments, such as shopping centres, childcare centres, schools, medical centres and retail hubs, associated with new large residential developments and large customer loads; and
- electrification of gas and transport sectors of society, associated with the energy transition.

The identified need for this RIT-T is to maintain electricity supply reliability and reduce expected unserved energy (EUE) for those customers supplied from SMTS.

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 SMTS - a lack of "N" capacity (system normal - with all plant in service), and a lack of "N-1" capacity (single contingency - with one transformer out of service).

Table 3 summarises the forecast "N" system normal capacity limitations at SMTS. The underlying maximum demand forecasts are shown in section 3.2.2.

Table 3: SMTS capacity limitations (EUE for "N" condition)

YEAR[15]	POE10		POE50		PROBABILITY WEIGHTED[16]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)[17]
2025	0.0	0	0.0	0	0.0	0.00
2026	0.0	0	0.0	0	0.0	0.00
2027	0.0	0	0.0	0	0.0	0.00
2028	0.0	0	0.0	0	0.0	0.00
2029	0.7	< 1	0.0	0	0.0	0.00
2030	26.7	9	0.0	0	0.0	0.00
2031	54.5	26	0.0	0	15.3	0.63
2032	83.3	38	7.1	1	125.4	5.20
2033	133.6	58	31.4	6	341.1	14.14
2034	186.7	100	55.1	18	655.2	27.16

[15] Financial year ending 30th June.
[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 distribution feeders load transfer capabilities. This weighting is consistently used by the Victorian DNSPs in its TCPR.
[17] These EUE cost estimates have been calculated by multiplying the EUE (MWh) by the load-weighted value of customer reliability for the South Morang supply area ($41,449/MWh, as set out in section **Error! Reference source not found.**, below).

There is forecast to be insufficient capacity to supply the growing demand at SMTS from 2028-29 under system normal ("N") operating conditions for a POE10 maximum demand. The station "N" cyclic rating is expected to be reached under a POE50 forecast from summer 2031-32.

The 'N' EUE is estimated to have a value to consumers of around $27.16 million (real, 2025) by 2033-34.

Table 4 provides a summary of the forecast "N-1" single contingency condition capacity limitations at SMTS (i.e., excluding the "N" system normal limitations presented above). The underlying maximum demand forecasts are shown in section 3.2.2.

Table 4: SMTS capacity limitations (EUE for "N-1" condition)

YEAR[18]	POE10		POE50		PROBABILITY WEIGHTED[19]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)[20]
2025	155.0	1,022	110.0	512	20.0	0.83
2026	175.5	1,627	128.7	983	47.6	1.97
2027	202.7	2,339	153.0	1,628	129.5	5.37
2028	227.8	2,903	175.7	2,094	255.0	10.57
2029	250.0	3,384	196.4	2,545	413.1	17.12
2030	250.0	3,890	220.1	3,044	621.2	25.75
2031	250.0	4,398	245.5	3,753	882.9	36.59
2032	250.0	4,914	265.0	4,419	1,190.2	49.33
2033	250.0	5,291	265.0	4,930	1,506.0	62.42
2034	250.0	5,690	265.0	5,337	1,845.6	76.50

The historical and forecast maximum demand under a transformer outage ("N-1") has exceeded the cyclic rating of SMTS every year since 2015-16, with levels of "N-1" load-at-risk during peak loading periods reaching the full transformer capacity of 250 MVA from 2028-29 for a POE10 forecast maximum demand. For an outage of one 220/66 kV transformer at SMTS, there will be insufficient capacity at this terminal station to supply all demand at the POE10 forecast maximum demand for about 1,627 hours in 2025-26, and 983 hours for the POE50 forecast maximum demand.

The probability of a major transformer outage is very low, with a network average of 1.0 per cent per transformer per annum applied for this assessment[21], contributing to an expected unavailability per transformer per annum of 0.22 per cent.

The post-contingent emergency load transfer away from SMTS to other terminal stations is 32.5 MVA. This is implemented by way of 22 kV distribution feeder transfers within the JEN and AusNet distribution networks.

When the energy-at-risk is weighted by the low unavailability, and emergency load transfer capability is considered, the EUE is estimated to be around 47.6 MWh in 2025-26. This EUE is estimated to have a value to consumers of around $1.97 million (real, 2025). By 2033-34, this increases to 1,845.6 MWh and $76.50 million (real, 2025).

The estimates of EUE and its financial value assumes a 70 per cent weighting of moderate temperatures (POE50) occurring in each year, and a 30 per cent weighting of higher temperature conditions (POE10), using a location-specific load-weighted value of customer reliability (VCR) of $41,449/MWh.[22]

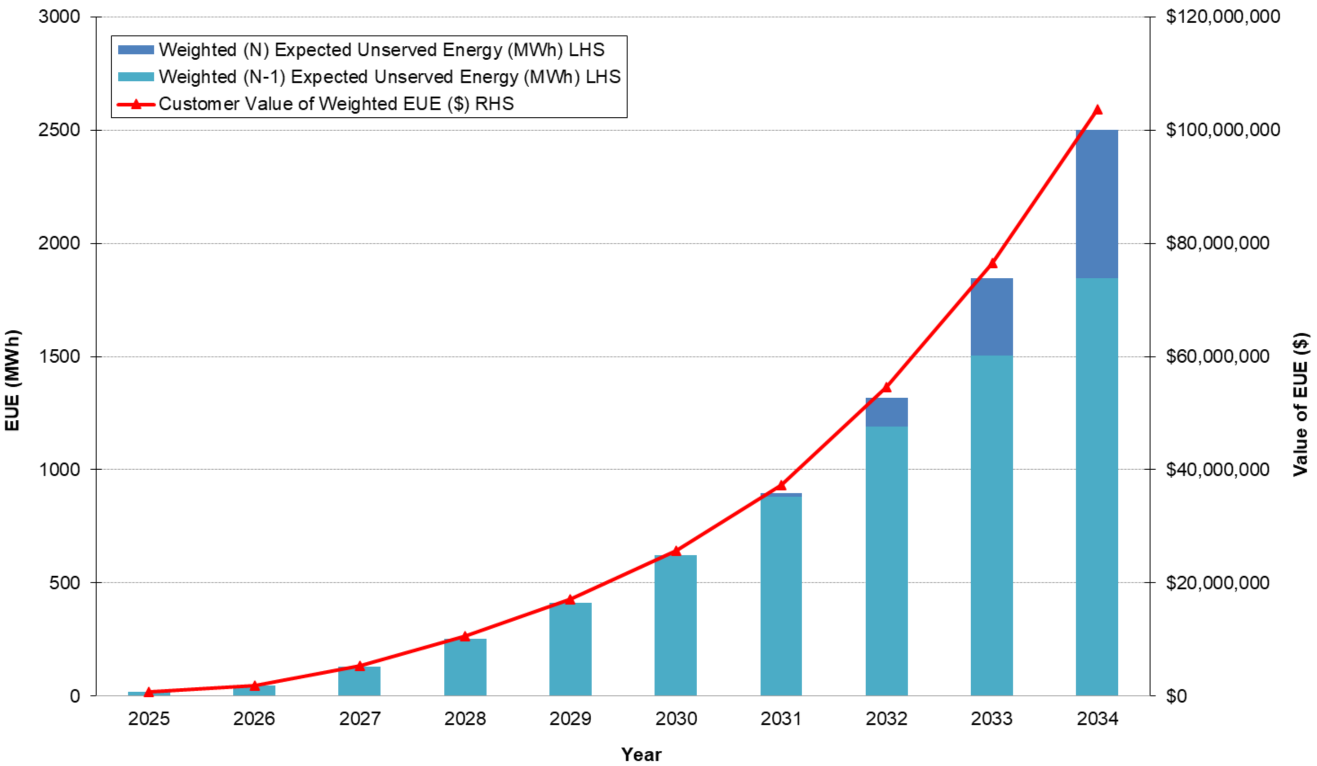
[18] Financial year ending 30th June.
[19] 30% weighting on POE10 EUE and 70% weighting on POE50 EUE, also considering the risk reduction provided by the combined available distribution and sub-transmission load transfer capabilities. This weighting is consistently used by the Victorian DNSPs in its TCPR.
[20] These EUE cost estimates have been calculated by multiplying the EUE (MWh) by the load-weighted value of customer reliability for the South Morang supply area ($41,449/MWh, as set out in section **Error! Reference source not found.**, below).
[21] Consistent with the TCPR.
[22] See section **Error! Reference source not found.**.

The key elements of the "Do Nothing" supply reliability risk under the status-quo are shown in Table 5 and Figure 5 for both "N" and "N-1" conditions, including the risk-reduction effects of available load transfer capability.

Table 5: SMTS total combined capacity limitations (EUE for "N" and "N-1" conditions)

YEAR[23]	PROBABILITY WEIGHTED[24]		YEAR	PROBABILITY WEIGHTED	
	EUE (MWh)	EUE Cost ($ million)[25]		EUE (MWh)	EUE Cost ($ million)
2025	20.0	0.83	**2030**	621.2	25.75
2026	47.6	1.97	**2031**	898.2	37.20
2027	129.5	5.37	**2032**	1,315.6	54.50
2028	255.0	10.57	**2033**	1,847.1	76.60
2029	413.1	17.12	**2034**	2,500.8	103.70

Figure 5: SMTS EUE risk costs (taking account of available load transfer capability)



It is the EUE associated with the "N-1" capacity of SMTS that is driving the bulk of the risk cost.

By undertaking one of the options proposed in this RIT-T, AusNet and JEN will be able to avoid this projected deterioration in supply reliability for the South Morang supply area.

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[23] Financial year ending 30th June.
[24] 30% weighting on POE10 EUE and 70% weighting on POE50 EUE, also considering the risk reduction provided by the combined available distribution and sub-transmission load transfer capabilities. This weighting is consistently used by the Victorian DNSPs in its TCPR.
[25] These EUE cost estimates have been calculated by multiplying the EUE (MWh) by the load-weighted value of customer reliability for the South Morang supply area ($41,449/MWh, as set out in section **Error! Reference source not found.**, below).

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.[26] This chapter details the assumptions used in identifying the identified need.

First, we set out the probabilistic planning approach applied by AusNet and JEN in planning the network, in the context of our overall approach to the net present value (NPV) analysis under the RIT-T. Chapter 6 then provides further detail on key assumptions that AusNet and JEN currently expect to adopt for the next stage of the RIT-T.

3.1. Overview of proposed approach to the NPV analysis

Consistent with the RIT-T NER requirements[27], cost benefit analysis guidelines[28] and RIT-T application guidelines[29], AusNet and JEN 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 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 6.

In planning the network, AusNet and JEN 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 monetised 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, AusNet and JEN 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 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.

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.

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[26] NER, clause 5.16.4(b)(2); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.
[27] Regulatory investment test for transmission, Australian Energy Regulator, 21 November 2024.
[28] Cost Benefit Analysis guideline, Australian Energy Regulator, 21 November 2024.
[29] RIT-T application guideline, Australian Energy Regulator, 21 November 2024.

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;
- maximum demand forecast;
- 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 SMTS is limited by the thermal cyclic rating of its two parallel 220/66 kV 225 MVA transformers. Table 6 provides a summary of the capability of SMTS for "N" and "N-1" conditions during summer and winter (maximum demand) seasons.

Table 6: SMTS thermal capacity cyclic ratings (MVA)

SEASON	EXISTING	
	"N"	"N-1"
Summer 35 Degrees Celsius	530	265
Summer 40 Degrees Celsius	500	250
Winter 15 Degrees Celsius	588	294

Section 5.3 shows how these thermal capacity ratings would be expected to increase following the implementation of the proposed preferred *network* option.

3.2.2. Forecast maximum demand

The forecast maximum demand at SMTS is specified according to its 10 per cent probability of exceedance (POE10) and its 50 per cent probability of exceedance (POE50) during summer and winter periods[30]. Table 7 provides a summary of the forecast maximum demand for SMTS during summer and winter (maximum demand) seasons.

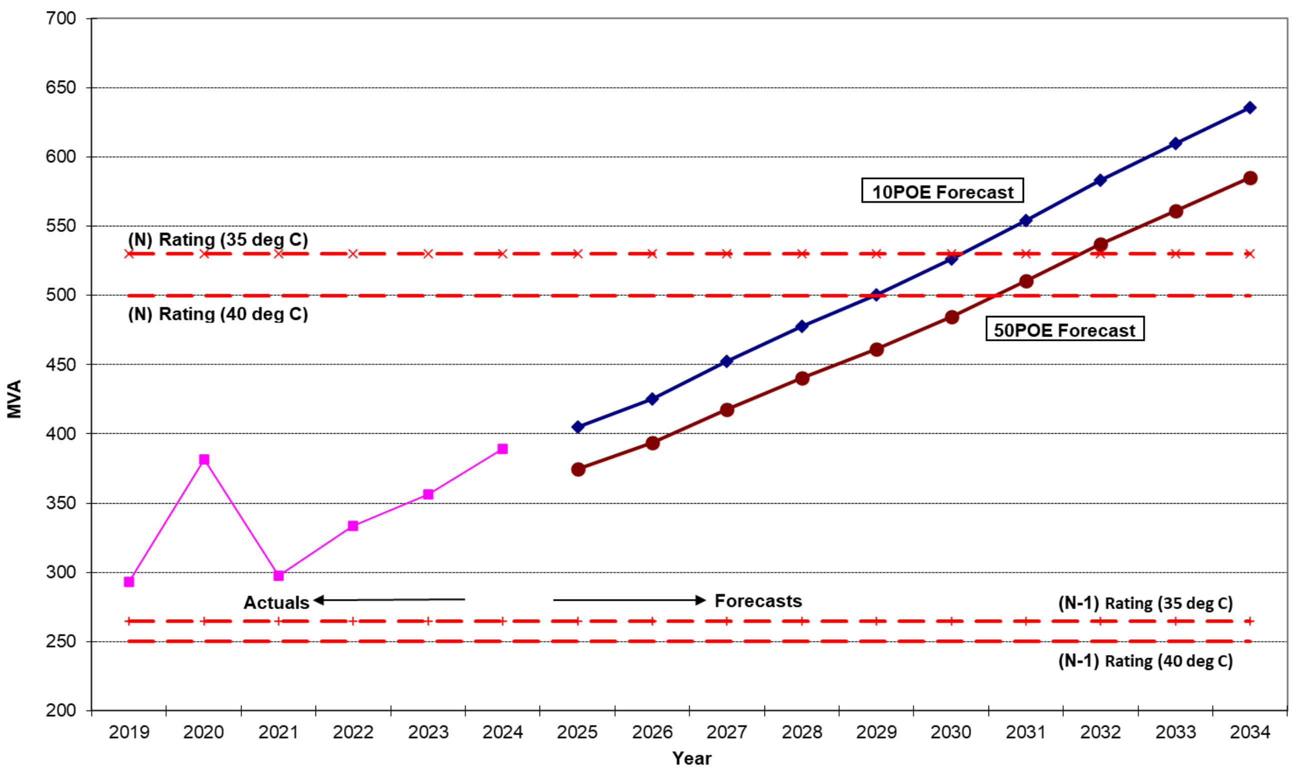
[30] Victorian electricity demand is sensitive to ambient temperature. Maximum demand forecasts are therefore based on expected demand during extreme temperature that could occur once every ten years (POE10) and during average conditions that could occur every second year (POE50).

Table 7: SMTS forecast maximum demand (MVA)

YEAR[31]	MAXIMUM DEMAND SEASON AND POE			
	Summer POE10	Winter POE10	Summer POE50	Winter POE50
2025	405	379	375	360
2026	426	406	394	386
2027	453	439	418	418
2028	478	468	441	446
2029	501	494	461	471
2030	527	522	485	499
2031	554	553	511	529
2032	583	584	537	559
2033	610	611	561	586
2034	636	639	585	612

Figure 6 shows the POE10 and the POE50 forecasts maximum demand for SMTS during summer periods relative to its capacity.

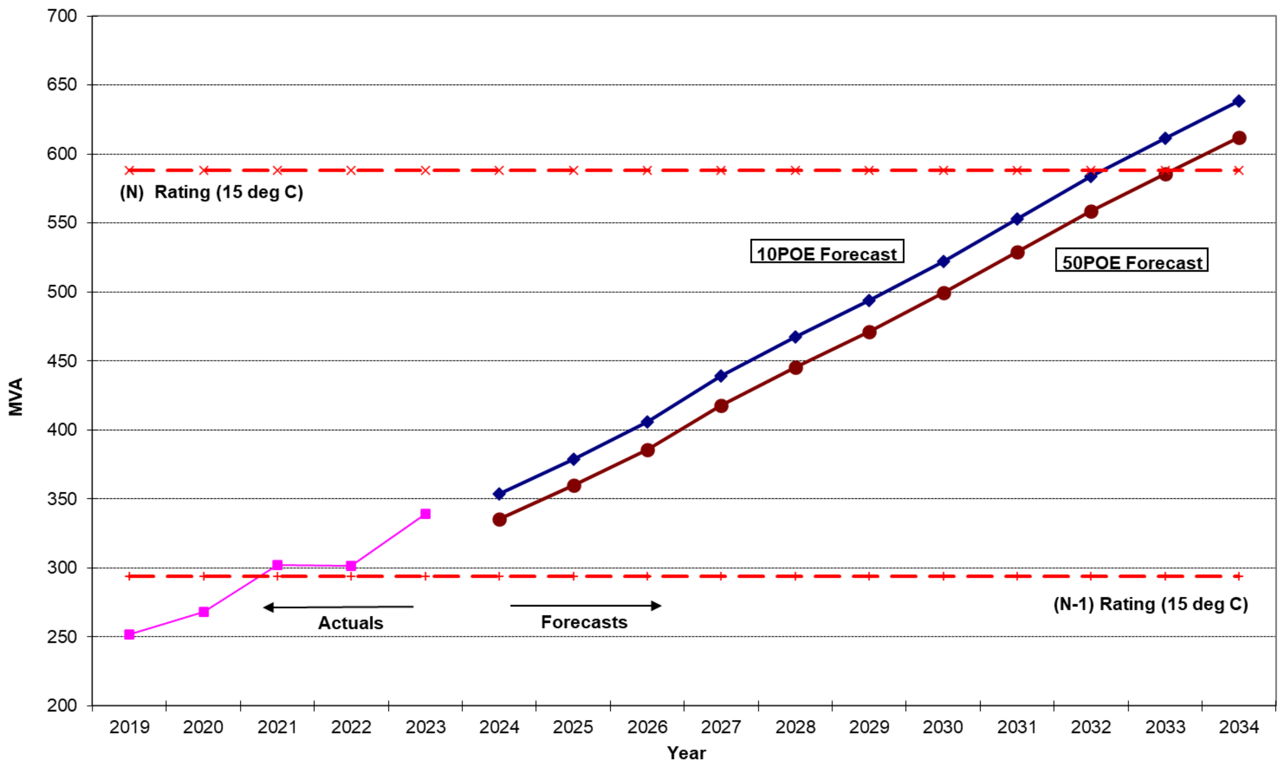
Figure 6: Summer period maximum demand forecasts for SMTS



[31] Financial year ending 30th June for summer demands. Calendar year ending 31st December for winter demands.

Figure 7 shows the POE10 and the POE50 forecast maximum demand for SMTS during winter periods relative to its capacity.

Figure 7: Winter period maximum demand forecasts for SMTS



The maximum demand growth in the SMTS supply area is primarily due to the following:

- staged development of residential estates and other residential subdivisions; commercial developments, such as shopping centres, childcare centres, schools, medical centres and retail hubs, associated with new large residential developments and large customer loads; and
- electrification of gas and transport sectors of society, associated with the energy transition.

The maximum demand forecasts used in this PSCR were prepared in late 2024.

3.2.3. Load transfer capability

Based on the present POE10 maximum demand, there is 32.5 MVA of 22 kV distribution feeder transfers available on the JEN and AusNet distribution networks from SMTS, being:

- 1.3 MVA available out of Epping Zone Substation (EPG);
- 12 MVA available out of Doreen Zone Substation (DRN);
- 1.4 MVA available out of Kinglake Zone Substation (KLK);
- 8.3 MVA available out of South Morang Zone Substation (SMG); and
- 9.5 MVA out of Somerton Zone Substation (ST).

The load transfer capability is limited by the peak utilisation on the adjacent distribution feeders of zone substations connected to other terminal stations.

Table 8 provides a summary of the forecast load transfer capability away from SMTS used to calculate the EUE.

Table 8: SMTS available transfer capability (MVA)

YEAR[32]	LOAD TRANSFER CAPABILITY (MVA)	
	Pre-contingent "N" risk	Post-contingent "N-1" risk
2025	32.5	32.5
2026	32.5	32.5
2027	32.5	32.5
2028	32.5	32.5
2029	32.5	32.5
2030	32.5	32.5
2031	32.5	32.5
2032	32.5	32.5
2033	32.5	32.5
2034	32.5	32.5

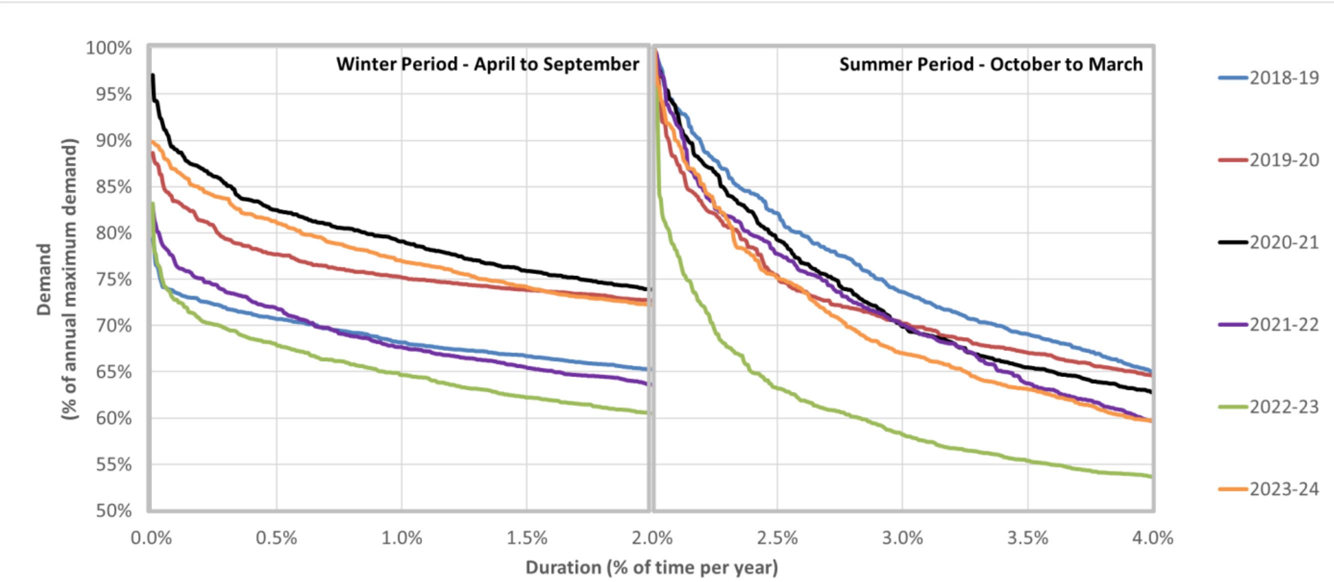
It is assumed load transfer capability will be maintained over the forecasting period.

3.2.4. Annual load profile

In calculating annual load profiles, consideration is made of underlying load and embedded generation contributions to the net load profile as observed at SMTS in the following charts. Underlying load is used as the basis on which to calculate EUE for this report.

The load-duration curves for SMTS over several recent years are shown in Figure 8 for peak demand periods, and in Figure 9 for the entire year.

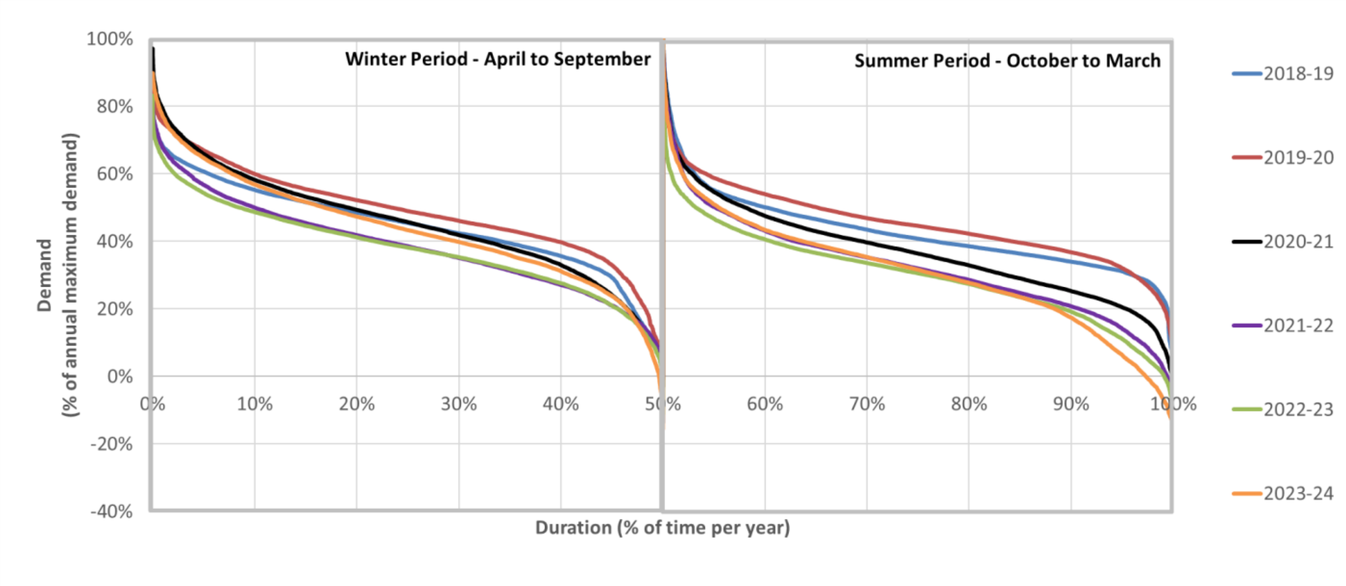
Figure 8: Load-duration profile for SMTS – peak demand



[32] Financial year ending 30th June.

The shape of the curves in Figure 8 are strongly 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 the largest differences observed between the 2020-21 and 2019-20 summers.

Figure 9: Load-duration profile for SMTS – annual

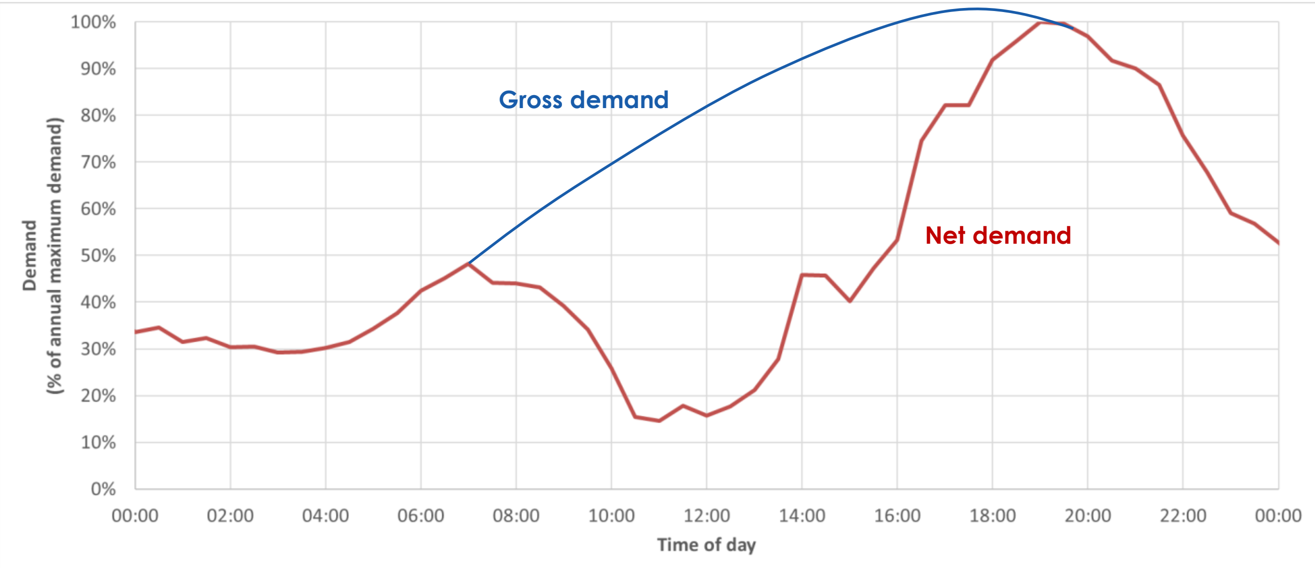


The shape of the net load curves in Figure 9 is influenced by the level of distributed roof-top PV, with more recent years tapering off rapidly (sharper peak, lower trough) compared to the more historical summers, and compared with the underlying load estimate.

About 180 MW of rooftop solar PV is installed on the AusNet distribution system and about 68 MW of rooftop solar PV is installed on the JEN distribution system connected to SMTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW. A total of 247.2 MW capacity of large-scale embedded generation is installed on the AusNet and JEN sub-transmission and distribution systems connected to SMTS.

The daily load profile at SMTS during the summer peak demand day is shown in Figure 10.

Figure 10: Peak demand daily load profile for SMTS (summer season)



3.2.5. Network asset reliability

Table 9 provides a summary of the SMTS transformer reliability information used in the EUE analysis.

Table 9: SMTS transformer reliability information[33]

POWER TRANSFORMER	VALUE	INTERPRETATION
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)	2.6 months	On average, 2.6 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 2.6/12 = 0.22% of the time, or 19 hours per year.

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

4. Technical characteristics NNO options 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 in the form of network support services, to alleviate the forecast capacity limitations at SMTS.[34] 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 SMTS.

4.1. Performance requirements

Initial analysis by AusNet and JEN has identified that, Option 3 (Install fourth 220/66 kV transformer at SMTS) is likely to be the preferred *network* option with an annualised cost of $3.7 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 5 and Figure 5 (being the combined values from Table 3 and Table 4), the EUE risk exceeds the annualised cost of the preferred *network* option in the summer of 2026-27, which represents the optimum date that a network support service needs to be in place to defer the preferred *network* option. The latest acceptable date being summer of 2027-28, to match that possible with 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 minimum amount of network support that AusNet and JEN are seeking from a non-network or SAPS option by summer 2027-28, is 25 MW[35]. It should however be noted that for this level of support, the amount a network support provider could claim is very little since the residual cost of EUE would only be marginally below the annualised deferral cost of the preferred *network* option.

To claim the majority of the maximum available annual payment from summer 2027-28, a network support option will be required to mitigate all load at risk for POE10 in Table 4 post-contingent. This post-contingent network support requirement is forecast to increase from 227.6 MW for up to 2,903 hours in 2027-28 (255.0 MWh pa probability weighted), up to 250.0 MW for up to 5,690 hours by 2033-34 (1,845.6 MWh pa probability weighted).

To claim all of the maximum available annual payment from summer 2027-28, a network support option will also be required to mitigate all of the load at risk for POE10 in Table 3 pre-contingent. This pre-contingent requirement is forecast to increase from 0.0 MW for up to 0 hours in 2027-28 (0.0 MWh pa probability weighted), up to 186.5 MW for up to 100 hours by 2033-34 (665.2 MWh pa probability weighted).

The maximum demand load curve in Figure 10 above, shows that the demand at SMTS typically remains high between 5:00pm and 10:00pm. Any pre-contingent network support solution will therefore typically need to be capable of operating continuously over this period, until the demand declines. Any post-contingent network support solution will need to be capable of operating continuously, during high demand periods when there is insufficient spare capacity in neighbouring distribution feeders, until the faulted asset is repaired or replaced, or the demand declines.

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 within the areas shown by Figure 1 and Figure 2.

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34 NER, clause 5.16.4(b)(3); AER, Regulatory investment test for transmission, Application guidelines, November 2024, section 4.2.
35 227.6 MW in 2028 – 202.6 MW in 2027 = 25 MW.

4.2. 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 AusNet and JEN 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)
    - 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 AusNet and JEN 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. AusNet Industry Engagement Strategy.
2. JEN Industry Engagement Guideline.

5. Description of potential credible options

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

- Option 1 – Do nothing (base case);
- Option 2 – Non-network or SAPS solution;
- Option 3 – Install fourth 220/66 kV transformer at SMTS;
- Option 4 – Install 3rd & 4th 220/66 kV transformers at SMTS;
- Option 5 – Establish two new feeders to offload SMTS (followed by Option 3); and
- Option 6 – Establish a new 220/66 kV Donnybrook terminal station (DBTS).

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. Option 5 and 6 are considered in this PSCR but unlikely to be progressed on the basis that they are either not technically credible, cost prohibitive or cannot meet the identified need in time.

5.1. Option 1 – Do nothing

The "Do-nothing" option continues to supply customers serviced by SMTS without any investment to manage increasing EUE levels, utilising only the available load transfer capability to manage the risk (i.e., status quo).

This option is expected to lead to significant supply interruptions and deteriorating supply reliability under both "N" (system normal) and "N-1" (single contingency) conditions at times of peak demand, because of capacity shortfalls at SMTS.

As detailed in Table 5 for the supply reliability risk associated with the combined "N" and "N-1" conditions, the value of the EUE risk associated with the "Do nothing" option (also shown in Figure 5), is forecast to increase from $1.97 million in 2025-26 to $103.7 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.

5.2. Option 2 – Non-network or SAPS solutions

Non-network or SAPS solutions contracted to provide network support services from within the distribution or sub-transmission networks serviced by SMTS, are targeted at reducing the net maximum demand on SMTS (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 storage and/or generation resources.

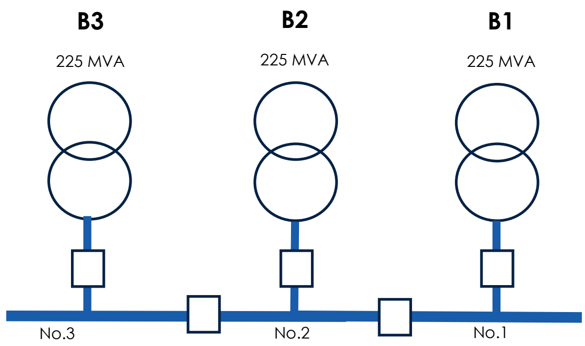
Chapter 4 details the required technical characteristics as well as the maximum fees available to a non-network or SAPS service provider, based on the current preferred *network* option. Network support may also be combined with suitable network augmentation options to defer or reduce the scope of a credible network option.

AusNet and JEN 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.

5.3. Option 3 - Install a 3rd 220/66 kV transformer at SMTS

This option involves installing a third 220/66 kV 225 MVA transformer at SMTS to increase the thermal capacity ratings of the transmission connection assets at this terminal station. There is already provision in the original design of the terminal station to accommodate a third transformer. A simplified single line diagram of the augmented transmission connection assets at SMTS is shown in Figure 11.

Figure 11: SMTS proposed transmission connection assets single line diagram (Option 3)



The scope of work required for this option includes:

- Supply and install one high impedance 220/66 kV 225 MVA transformer (to be installed in between existing B1 and B3, including fire walls).
- Add two, three-phase, series 220 kV reactors to the existing B1 and B3 transformers.
- Add three new 220 kV circuit breakers and associated equipment in Bay S of the 220 kV switchyard.
- Add automatic control scheme to switch the new transformer to the other 220 kV Bus if the normal bus is affected by a protection operation (220 kV auto-close scheme).
- Add 66 kV connection to the No.2 66 kV bus via new circuit breaker and associated equipment.
- Relocate 150 MVA 220/66 kV metro spare transformer to new bunded area adjacent to F Trans spare unit.
- Install and modify protection, monitoring and control equipment.

This option meets the identified need by alleviating the load at risk and removing nearly all the EUE at SMTS over the medium term, after installation of the third transformer at SMTS.

Based on an initial assessment, this option maximises the net market benefits and is therefore likely to be the preferred *network* option.

The estimated capital cost of this network option is $43.56 million (real, 2025) which has present value of $38.5 million and an annualised cost of $3.7 million (includes $0.4 million of operating and maintenance costs). Based on this annualised cost and the EUE costs in Table 5, the optimal timing for commissioning the third transformer is before summer 2026-27. With a construction timetable of two to three years, the timing is 2027-28.

The expected SMTS thermal capacity ratings following the implementation of Option 3 are shown in Table 10, below.

Table 10: SMTS thermal capacity rating if Option 3 is implemented (MVA)

SEASON	B123	
	"N"	"N-1"
Summer 35 Degrees Celsius	795	530
Summer 40 Degrees Celsius	750	500
Winter 15 Degrees Celsius	882	588

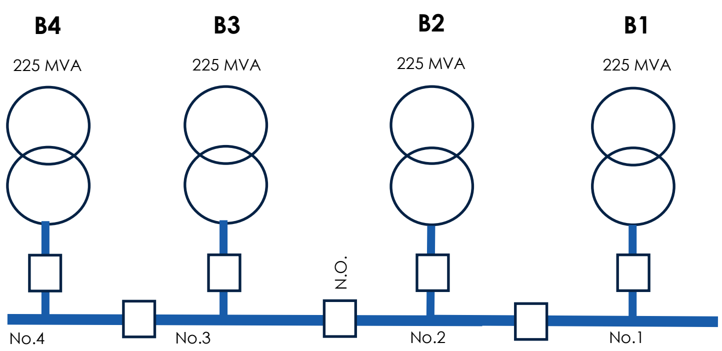
This option is not likely to have a material inter-network impact.

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

5.4. Option 4 - Install 3rd & 4th 220/66 kV transformers at SMTS

This option involves installing a third and fourth 220/66 kV 225 MVA transformers at SMTS to increase the thermal capacity ratings of the transmission connection assets at this terminal station. There is already provision in the original design of the terminal station to accommodate a third and fourth transformer. A simplified single line diagram of the augmented transmission connection assets at SMTS is shown in Figure 12.

Figure 12: SMTS proposed transmission connection assets single line diagram (Option 4)



The scope of work required for this option includes:

- Supply and install two high impedance 220/66 kV 225 MVA transformers.
- Add two, three-phase, series 220 kV reactors to the existing B1 and B3 transformers.
- Add three new 220 kV circuit breakers and associated equipment in Bay S of the 220 kV switchyard.
- Add automatic control scheme.
- Add 66 kV bus augmentations.
- Relocate 150 MVA 220/66 kV metro spare transformer to new bunded area adjacent to F Trans spare unit.
- Install and modify protection, monitoring and control equipment.
- 66 kV feeder bay reallocations.

This option meets the identified need by alleviating the load at risk and removing all the EUE at SMTS, after installation of the third and fourth transformers at SMTS, over the next ten years.

The estimated capital cost of this network option is $ 55.5 million (real, 2025) which has present value of $49.1 million and an annualised cost of $4.7 million (includes $0.5 million of operating and maintenance costs). Based on this annualised cost and the EUE costs in Table 5, the optimal timing for commissioning the third and fourth transformers is before summer 2026-27. With a construction timetable of three years, the timing is 2027-28.

The expected SMTS thermal capacity ratings following the implementation of Option 4 are shown in Table 11, below.

Table 11: SMTS thermal capacity rating if Option 4 is implemented (MVA)

SEASON	B12		B34	
	"N"	"N-1"	"N"	"N-1"
Summer 35 Degrees Celsius	530	265	530	265
Summer 40 Degrees Celsius	500	250	500	250
Winter 15 Degrees Celsius	588	294	588	294

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 substation. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

5.5. Option 5 - Establish two new 10 MVA feeders to offload SMTS, followed by Option 3

<u>This option has been considered but will likely not be progressed on the basis that it may not be technically feasible.</u>

This option involves establishing two new 22 kV 10 MVA distribution feeders to increase the transfer capacity away from SMTS and reduce the post-contingent EUE exposure at SMTS.

Table 12 provides a summary of the new feeder opportunities and the increase in transfer capability provided to SMTS by each of those feeders, considering the available spare capacity on their upstream assets and the maximum demand on the feeders being transferred.

Table 12: New 22 kV distribution feeder opportunities to increase transfer capacity of SMTS

TO NEW FEEDER ZONE SUBSTATION	FROM SMTS ZONE SUBSTATION	TRANSFER CAPABILITY PROVIDED (MVA)
1st new feeder ex Eltham (ELM)	South Morang (SMG) part of SMG23, SMG31	10 MVA
2nd new feeder ex Eltham (ELM)	Doreen (DRN) part of DRN13, DRN23	10 MVA

The total increase in transfer capacity provided by this option is 20 MVA.

The estimated capital cost of the two new feeders is $20.0 million (real, 2025) which has present value of $18.3 million and an annualised cost of $1.6 million. Based on this annualised cost and the EUE costs in Table 5, the optimal timing for commissioning the new feeders being summer 2026-27, with a construction timetable of one to two years.

The total increase in transfer capacity provided by the two new feeders is 20 MVA, well below the load at risk. Hence investment in these feeders is unable to address the identified need on its own. With a maximum demand growth rate at SMTS being around the level of the additional transfer capacity provided, the two feeders are able to support the EUE risk in the lead up to implementing Option 3. Therefore, for the purposes of this RIT-T, this option is assumed to be undertaken with the Option 3.

The estimated capital cost of Option 5 is $63.56 million (real, 2025). This combined option meets the identified need by alleviating the supply capacity risk and removing nearly all the expected unserved energy over the next 10 years. The total present value capital cost of this combined network option is $56.6 million, and has an annualised cost of $5.5 million (includes $0.6 million of operating and maintenance costs), with the optimal timing for commissioning the new feeders being summer 2026-27 and the third transformer being summer 2027-28, with a construction timetable of two to three years.

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

Social licencing risks are considered moderate for this option as it only involves work within an existing established substation and standard overhead pole lines and underground cables within existing road reserves and easements. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

5.6. Option 6 - Establish a new 220/66 kV terminal station DBTS

<u>This option has been considered but will likely not be progressed on the basis that it is cost prohibitive and cannot meet the identified need in time.</u>

This option involves establishing a new two 220/66 kV 225 MVA transformers and two 500/220 kV 1,000 MVA transformers terminal station in the Donnybrook area (site owned by AusNet) to reduce the maximum demand on SMTS, transferring load to the new terminal station by re-arranging the existing sub-transmission network, thereby addressing the identified need. A possible solution would be to transfer 235 MVA of load as shown in Figure 13 and Figure 14.

Figure 13: Possible sub-transmission network schematic diagram (Option 6 - DBTS)

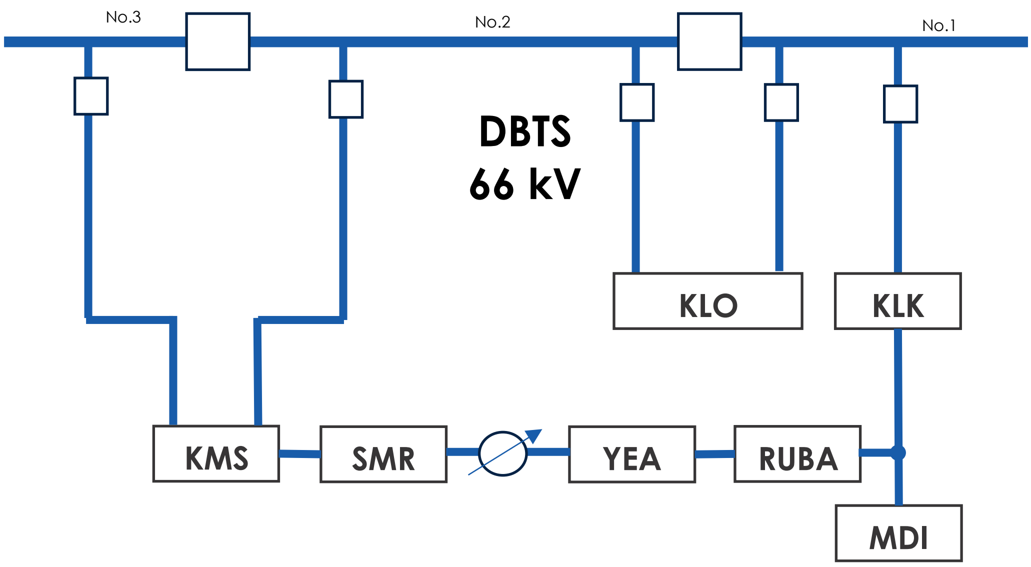


Figure 14: Possible sub-transmission network schematic diagram (Option 6 - SMTS)

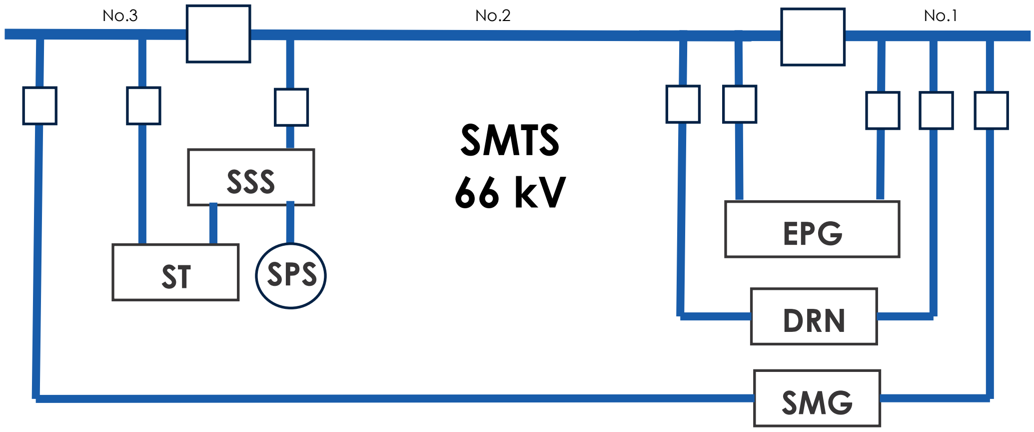


Figure 15: Land reserved for future Donnybrook terminal station geospatial diagram (Option 6)

This option is the most expensive option with a total estimated capital cost of $240 million (real, 2025) which, has a present value capital cost of $185.0 million, and has an annualised cost of $20.4 million (includes $1.2 million of operating and maintenance costs). Based on this annualised cost and the EUE costs in Table 5, the optimal timing for commissioning the new terminal station is before summer 2029-30, with a construction timetable of four to five years.

This option meets the identified need by alleviating the supply capacity risk and removing nearly all the expected unserved energy over the next 10 years. Nevertheless, there is significant EUE at risk in the lead up to this augmentation, given its long lead time.

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

The option involves work to establish a new terminal station, and standard overhead pole lines and underground cables within existing road reserves and new easements, to connect into the existing distribution network. Only existing 500 kV transmission line cut-ins through the designated site are required, with no new transmission lines or extensions required. Community consultation, social licencing and associated building, environmental, cultural heritage and planning permitting will be undertaken as part of this option in the years leading up to the construction works.

6. Proposed assessment methodology

This chapter discusses the proposed assessment methodology for the net present value (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.

6.1. Assessment parameters

6.1.1. 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. AusNet and JEN have applied locational VCR values based on the Australian Energy Regulator's (AER) Values of Customer Reliability Review published in December 2024[36].

Applying the AER's sector VCRs to terminal station level historical energy composition data from 2023-24, a SMTS VCR of $41,449/MWh was derived, as presented in Table 13.

Table 13: SMTS value of customer reliability

SECTOR	AER VCR ($/MWH)[37]	SMTS ENERGY CONSUMPTION BY SECTOR	SMTS WEIGHTED VCR ($/MWH)
Residential Suburban	55,100	32.4%	17,842
Residential Regional	38,900	16.7%	6,502
Commercial	34,390	36.4%	12,522
Industrial	33,490	12.1%	4,047
Agricultural	22,250	2.4%	535
Composite		**100%**	**41,449**

[36] Values of Customer Reliability, Australian Energy Regulator (AER) December 2024.
[37] AER 2024 published VCRs. Climate zone 6 applies at SMTS.

6.1.2. Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. A real, 7.0 per cent, commercial discount rate is used at SMTS, aligned with AEMO's 2023 inputs, assumptions and scenarios report[38] (IASR). For the sensitivities we use 10.5 per cent for the high bound, and 3.9 per cent for the low bound representing a regulatory discount rate.

6.1.3. Assessment period

It is necessary to apply a cost-benefit analysis assessment period commensurate with the options being evaluated to address the identified need. AusNet and JEN intend to undertake the RIT-T analysis over a 20-year period, with a terminal value included in the final year representing the net value of the asset over its remaining asset life. Monetised risks will be capped to their year 10 values from year 11 to the end of the evaluation period.

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 expected demand growth in the South Morang supply area intended to be addressed by the credible options in this RIT-T.

6.2. Approach to estimating option costs

The costs for each option have been calculated by AusNet Transmission Group's cost estimation team based on recent similar project costs and scope. Costs are expected to be within ±30 per cent of the actual cost (except for option 4 which has an accuracy of ±50 per cent).

The costs presented in this PSCR 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.

38 2023 Inputs, Assumptions and Scenarios Report, Table 31, AEMO July 2023.

6.3. 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:[39]

- 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 shedding (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:

- **Changes in fuel consumption arising through different patterns of generation dispatch**, as the network is not normally interconnected to the extent that asset failures cannot be remediated by re-dispatch of generation and the wholesale market impact is expected to be the same.
- **Changes in costs for parties, other than the RIT-T proponent,** 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 changes in greenhouse gas emissions from changes in generation dispatch, renewable energy generation curtailment, or levels of SF_6 emissions from high-voltage switchgear, are considered to be negligible and unlikely to be a material class of market benefits for any of the credible options.
- **Change in network losses**, as changes in network losses are considered to be negligible in comparison to other market benefits considered in this RIT-T and unlikely to be a material class of market benefits for any of the credible options, nor change the ranking of options considered.
- **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 ancillary services costs**, as the options are not expected to impact on the demand for and supply of ancillary services.
- **Differences in the timing of expenditure**, as the timing of other unrelated expenditure is not expected to be impacted by the options considered in this assessment.
- **Avoided unrelated network expenditure**, as we do not expect the options to affect other proposed network expenditure.
- **Changes in safety costs**, as the identified need is not driven by network asset condition. Therefore, this market benefit was not quantified as it was not considered to be relevant with respect to differentiating between options that address the identified need.
- **Competition benefits**, as there is no competing generation affected by the limitations and risks being addressed by the options considered for this RIT-T.

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

7. Submissions and next steps

7.1. Request for submissions

AusNet and JEN invites written submissions and enquires on the matters set out in this PSCR from interested stakeholders.

All submissions and enquiries should be titled "***South Morang Supply Area RIT-T***" and directed to both:

Ali Kharrazi (AusNet)

Manager, Sub-Transmission Network Planning

Email: rittconsultations@ausnetservices.com.au

and

Hung Nguyen (JEN)

Network Planning Team Leader

Email: PlanningRequest@jemena.com.au

The consultation on this PSCR is open for 12 weeks, consistent with the NER requirements[40]. Submissions are due on or before 30th September 2025.

Submissions may be published on the Australian Energy Market Operator (AEMO), AusNet and JEN 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 PCSR consultation period, AusNet and JEN will, having regard to any submissions received on the PSCR, prepare and publish a project assessment draft report (PADR) including:

- A summary of, and commentary on, the submissions on the PSCR;
- A detailed market benefit assessment of the proposed credible options to address the identified need; and
- Identification of the proposed preferred option to meet the identified need.

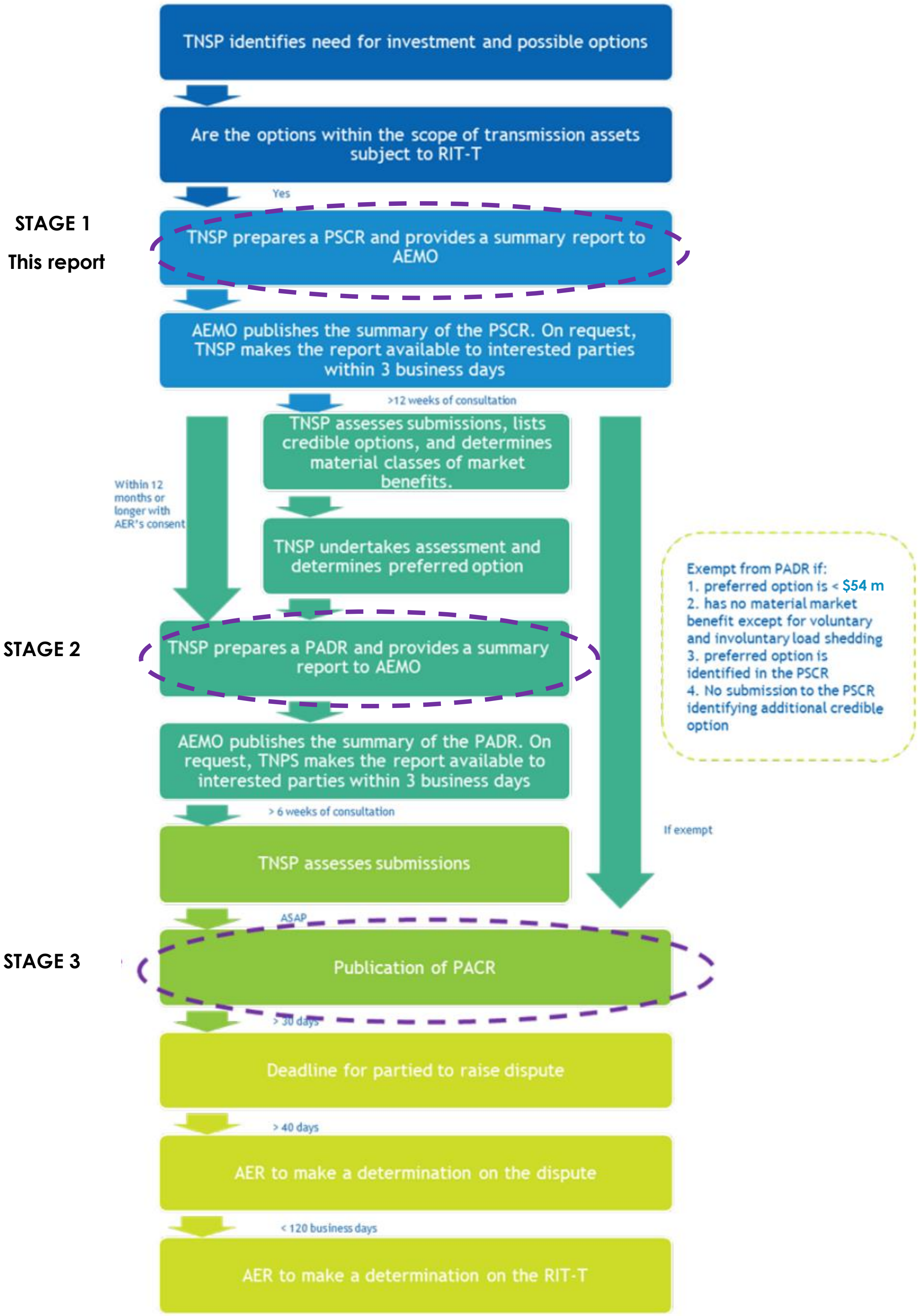
Publication of that report will trigger the second stage of consultation on this RIT-T.

AusNet and JEN intend on publishing the PADR in the fourth quarter of 2025.

[40] NER, clause 5.16.4(g).

A. RIT-T assessment and consultation process

Figure 16: RIT-T Process



B. RIT-T compliance checklist

This appendix sets out a checklist in Table 14 which demonstrates the compliance of this PSCR with the requirements of clause 5.16.4(b) of the NER version 230.

Table 14: 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 4
(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 5
(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.	

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

Table 15: AER guidelines PSCR compliance checklist

SUMMARY OF THE REQUIREMENTS:	CHAPTER
3.2.5 A RIT-T proponent must consider social licence issues in the identification of credible options. A RIT proponent should include information in its RIT reports about when and how social licence considerations have affected the identification and selection of credible options.	Chapter 5
3.4.3 The value of emissions reduction (VER), reported in dollars per tonne of emissions (CO_2 equivalent), is used to value emissions within a state of the world. A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.	Not applicable
3.5A.1 Where the estimated capital costs of the preferred option exceeds $103 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application: • outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T • for all credible options (including the preferred option), either – apply the cost estimate classification system published by the AACE, or – if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.	Chapter 6, if applicable
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 6
3.5 In the RIT-T, costs must include the following classes: Costs incurred in constructing or providing the credible option Operating and maintenance costs over the credible option's operating life Costs of complying with relevant laws, regulations and administrative requirements For, asset replacement projects or programs, there are costs resulting from removing and disposing of existing assets, which a RIT-T assessment should recognise. RIT-T proponents should include these costs in the costs of all credible options that require removing and disposing of retired assets. For completeness, the RIT-T proponent would exclude these costs from the 'BAU' base case.	Chapter 5
3.5.3 The RIT-T proponent is required to provide the basis for any social licence costs in its RIT-T reports and may choose to refer to best practice from a reputable, independent and verifiable source.	Chapter 5
3.6 RIT-T proponents are required to apply classes of market benefits consistently across all credible options.	Refer PADR

3.7.3 When calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to: • include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome: • direct emissions from generation • direct emissions other than from generation estimate the change in annual emissions (once identified in accordance with this Guideline) between the base case and the credible option, and multiplying this change by the annual VER to arrive at the annual benefit from changes in Australia's greenhouse gas emissions.	Not applicable
3.8.2 Where the estimated capital cost of the preferred option exceeds $103 million (as varied in accordance with an applicable cost threshold determination), a RIT-T proponent must undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.	Not applicable
3.9.4 If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and how the level or quantum of the contingency allowance was determined.	Not applicable
3.11.2 Where a concessional finance agreement is included, the RIT-T proponent is required to provide sufficient detail about the concessional finance agreement to justify an agreement's inclusion and such that it can articulate how the value of the concession is to or would be shared with consumers. If a proponent seeks to include an unexecuted concessional finance agreement in the RIT-T, they must undertake sensitivity testing for the scenario the agreement doesn't eventuate.	Not applicable
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 5, separately for each option

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