AusNet

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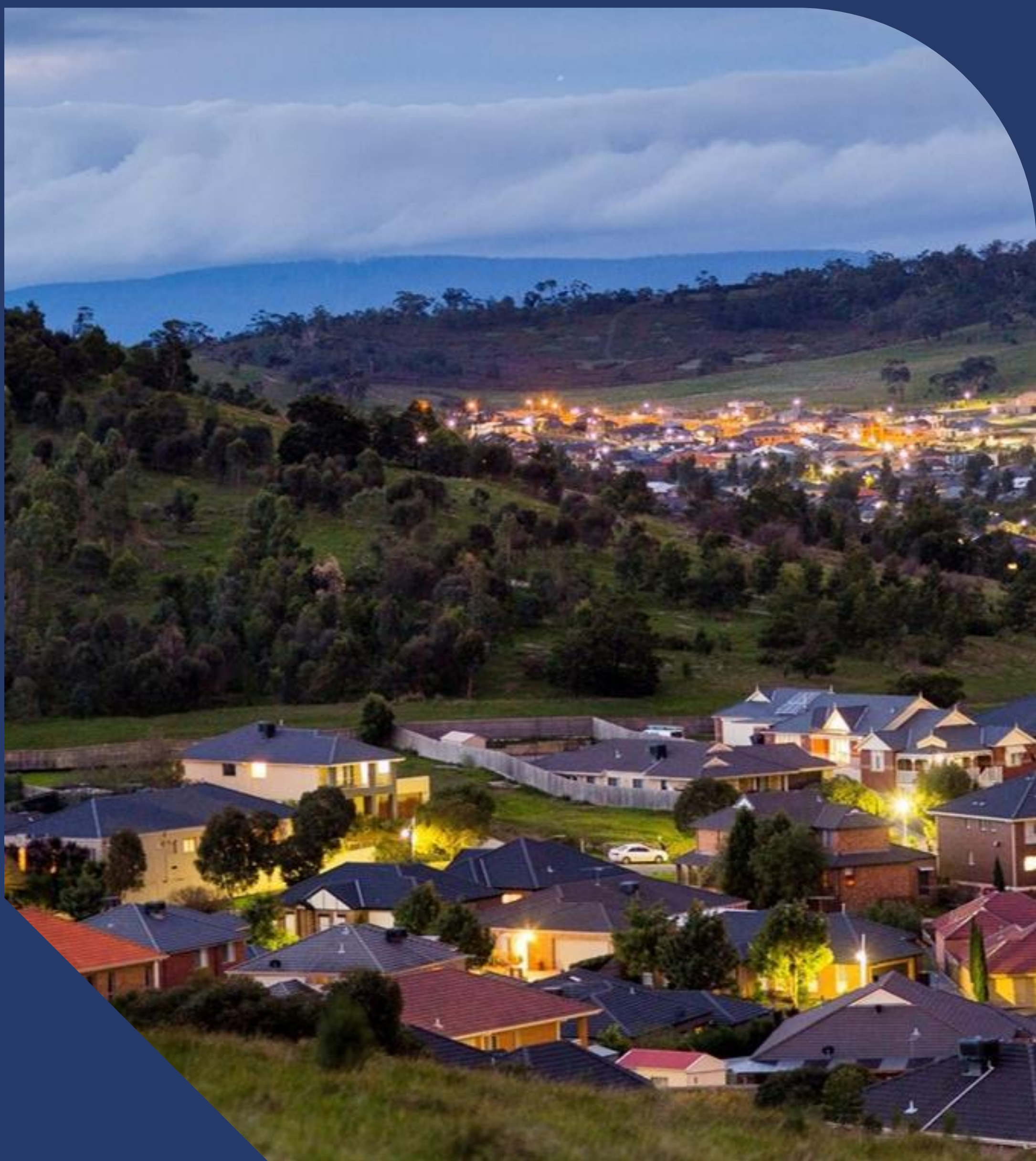
Maintaining supply reliability in the Cranbourne supply area

RIT-T Project Assessment Draft Report

Friday, 6 June 2025



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Important notice

Purpose

AusNet and United Energy have prepared this project assessment draft report (PADR) in accordance with clause 5.16.4 of the National Electricity Rules (NER). This PADR is the second stage of the *Cranbourne Supply Area* Regulatory Investment Test for Transmission (RIT-T) consultation process, relating to maintaining supply reliability in the Cranbourne supply area.

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Executive summary

AusNet and United Energy are regulated Victorian Distribution Network Service Providers (DNSPs) that supply electricity distribution services to more than 809,000 and 727,000 customers respectively. AusNet's electricity distribution network services eastern regional Victoria and the outer northern and eastern Melbourne metropolitan area. United Energy's electricity distribution network services the east and south-east Melbourne metropolitan area and the Mornington Peninsula.

As expected by our customers and required by the various regulatory instruments that we operate under, AusNet and United Energy 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 Cranbourne Terminal Station (CBTS) in excess of the trigger threshold of $8 million[1], and is therefore subject to a regulatory investment test for transmission (RIT-T). CBTS supplies electricity to parts of the AusNet and United Energy (the lead proponent of this RIT-T) electricity distribution networks.

AusNet and United Energy are undertaking a RIT-T process to evaluate options to maintain reliability of supply in the Cranbourne supply area. Options investigated in this RIT-T aim to mitigate the risk of a deterioration in power supply reliability from the transmission connection assets at CBTS that service the Cranbourne supply area.

Our RIT-T analysis shows that it is no longer economically viable to continue to service peak electricity demand using the existing installed capacity of transmission connection assets at CBTS. The supply reliability risk quantified by the expected unserved energy (EUE), has increased to a level where investment to increase capacity for the area offers a more economical alternative to the status-quo, based on the value that consumers place on supply reliability.

In October 2024, AusNet and United Energy published the project specification consultation report (PSCR), which represented the first stage of this RIT-T process in accordance with clause 5.16 of the National Electricity Rules (NER)[2] and section 4.2 of the RIT-T Application Guidelines[3]. The PCSR identified that the preferred *network* option to address the supply reliability need at CBTS, is likely to be the installation of a fourth 150 MVA 220/66 kV transformer at CBTS.

During the PSCR consultation period, no non-network proposals or submissions were received from interested stakeholders. As a consequence and given the capital cost of the preferred network option is greater than the trigger threshold of $54 million[4] for publication of a project assessment draft report (PADR), AusNet and United Energy have now prepared this PADR in accordance with clause 5.16 of the NER and section 4.3 of the RIT-T Application Guidelines. The PADR is the second stage of the RIT-T process and incorporates the assessment results of the credible options, providing draft conclusions on the proposed preferred option for addressing the identified need in the Cranbourne supply area.

This PADR proposes the preferred option and its optimal timing, being the installation of a fourth 150 MVA 220/66 kV transformer at CBTS at an estimated capital cost of $56.0 million (real, 2025) by 2026-27, as the option that satisfies the requirements of the RIT-T.

Identified need

The identified need for this RIT-T is to deliver market benefits by maintaining electricity supply reliability and reducing expected unserved energy (EUE) for those customers supplied from CBTS.

CBTS is owned and operated by AusNet and is located in Cranbourne in Melbourne's outer south eastern suburbs in Victoria. It was commissioned in 2005 and serves as the main transmission connection point for distribution of electricity to customers to those parts within the AusNet and United Energy distribution service areas incorporating the Cranbourne supply area.

CBTS supplies electricity to more than 198,000 customers, with residential customers consuming 49.5 per cent of the total annual energy supplied from CBTS, closely followed by commercial customers at 42.1 per cent. The geographic coverage of the area supplied by the transmission connection assets at CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west.

Electricity demand at CBTS has been amongst the fastest growing in Victoria, and CBTS has reached its full capacity. The summer peak demand at CBTS increased by 172 MVA between 2007-08 and 2019-20, equivalent to an average annual growth rate of 4.1 per cent. In 2023-24, the summer maximum demand on CBTS reached 503.2 MW (519.4 MVA), which is the historical maximum for this terminal station.

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[1] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER).
[2] National Electricity Rules, version 227, Australian Energy Market Commission (AEMC), 2025.
[3] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.
[4] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER).

The summer cyclic rating of CBTS with all plant in service is 553 MVA at 35°C and 540 MVA at 40°C. This rating is expected to be exceeded in 2025-26 for the POE50 and the POE10 forecast summer maximum demands[5]. The summer cyclic rating of CBTS with one of its three transformers out of service, reduces to 369 MVA at 35°C and 360 MVA at 40°C and this rating is expected to be exceeded every year from now.

The maximum demand growth in the CBTS 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 development of light industrial areas; 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 for customers in the Cranbourne supply area. Due to the strong demand growth in the area and the high utilisation of CBTS at maximum demand, the level of EUE resulting from capacity limitations at CBTS is forecast to grow, deteriorating supply reliability for our customers.

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 net economic benefit. The need for this investment has been foreshadowed in the 2024 Transmission Connection Planning Report (TCPR)[6], published jointly by the Victorian DNSPs.

Potential credible options

The PSCR presented options designed to address the identified need for continuing to reliably meet the electricity demand requirements of customers within the Cranbourne supply area. The credible options considered were:

- Option 1 - Do Nothing;
- Option 2 - Non-network or SAPS solution;
- Option 3 - Install fourth 220/66 kV transformer at CBTS;
- Option 4 - Install two 50 MVAR 66 kV capacitor banks at CBTS (followed by Option 3);
- Option 5 - Establish two new 22 kV feeders to offload CBTS (followed by Option 3); and
- Option 6 - Establish a new 220/66 kV terminal station.

All of the network options identified in the PSCR are assessed in this PADR, however Option 6 was considered but not progressed on the basis that it cost prohibitive and cannot meet the identified need in time, given no site has been procured to accommodate the new terminal station.

No non-network proposals were received during the Cranbourne supply area RIT-T PSCR consultation, therefore Option 2 is not considered to be a credible option for the purposes of this PADR.

Assessment approach

AusNet and United Energy applied the AER's RIT-T Application Guidelines to analyse and rank the economic cost and benefits of the investment options considered in this RIT-T across a range of reasonable scenarios. The robustness of the ranking and optimal timing of options have been investigated through sensitivity analysis that involve variations of assumptions around the values used in the base case. None of the options considered propose to make a material impact on wholesale market costs and hence no market simulation studies have been conducted for this RIT-T.

Options assessment and draft conclusion

The preferred option is that option which maximises the present value of the net economic benefit, weighted across a set of reasonable state-of-the-world scenarios.

A cost-benefit economic evaluation assessment was undertaken for this PADR, and a summary of the net present value analysis for each option and each scenario is provided in Table 1.

[5] 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.
[6] Transmission Connection Planning Report, Victorian Distribution Network Service Providers, 2024.

Table 1 – Calculated present value of net economic benefits relative to base case ($ million, real 2025)

OPTION	LOW SCENARIO	CENTRAL SCENARIO	HIGH SCENARIO	WEIGHTED SCENARIO	
Weighting	**35%**	**50%**	**15%**	**100%**	**Rank**
Option 1	0	0	0	0	5
Option 3	135	1,109	2,801	1,022	1
Option 4	128	1,108	2,812	1,021	2
Option 5	128	1,108	2,811	1,020	3
Option 6	(14)	961	2,648	873	4

The RIT-T analysis has concluded that the proposed preferred option to address the identified need is Option 3 (Install a fourth 150 MVA 220/66 kV transformer at CBTS). This proposed preferred option is found to have positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver $1,022 million in present value net economic benefits over the lifecycle. The estimated capital cost of this option is $56.0 million ±30 per cent (real, 2025) with an optimum timing of 2026-27. This option satisfies the requirements of the RIT-T.

Submissions

AusNet and United Energy invite written submissions and enquires on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "***Cranbourne Supply Area RIT-T***", and directed to both:

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The consultation on this PADR is open for 6 weeks, consistent with the NER requirements[7]. Submissions are due on or before 18th July 2025.

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

- a summary of, and commentary on, the submissions on the PADR;
- the matters detailed in the PADR; and
- confirming the preferred option to meet the identified need.

Publication of that report will conclude the RIT-T consultation.

AusNet and United Energy intend on publishing the PACR in the third quarter of 2025.

[7] NER, clause 5.16.4(r).

1. Introduction

AusNet and United Energy are regulated Victorian Distribution Network Service Providers (DNSPs) that supply electricity distribution services to more than 809,000 and 727,000 customers respectively. AusNet's electricity distribution network services eastern regional Victoria and the outer northern and eastern Melbourne metropolitan area. United Energy's electricity distribution network services the east and south-east Melbourne metropolitan area and the Mornington Peninsula.

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 the 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)[8] and is summarised in Figure 18 of Appendix A of this document.

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[9]. AusNet and United Energy are undertaking this RIT-T to evaluate options to maintain reliability of supply in the Cranbourne 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 Cranbourne Terminal Station (CBTS). The capital cost of credible options (including the preferred network option) to address this identified need within the Cranbourne supply area is above the RIT-T cost threshold and so has triggered the requirement for a RIT-T.

In October 2024, AusNet and United Energy published the project specification consultation report (PSCR), which represented the first stage of this RIT-T process in accordance with clause 5.16 of the NER and section 4.2 of the RIT-T Application Guidelines[10]. The PCSR identified that the preferred *network* option to address the supply reliability need at CBTS, is likely to be the installation of a fourth 150 MVA 220/66 kV transformer at CBTS, that would be confirmed during the RIT-T process. The need for this investment has been foreshadowed in the 2024 Transmission Connection Planning Report (TCPR)[11], published jointly by the Victorian DNSPs.

During the PSCR consultation period, no non-network proposals or submissions were received from interested stakeholders.

We have now published this project assessment draft report (PADR), representing the second stage of the *Cranbourne Supply Area RIT-T* consultation process in accordance with clause 5.16 of the NER and section 4.3 of the RIT-T Application Guidelines.

The structure of this PADR is as follows:

- **Chapter 2** describes the identified need that AusNet and United Energy are seeking to address, which is in relation to the CBTS capacity limitations;
- **Chapter 3** identifies credible options that aim to address the identified need;
- **Chapter 4** provides a summary and commentary on the submissions to the PSCR;
- **Chapter 5** details the assumptions that AusNet and United Energy have employed for this RIT-T assessment;
- **Chapter 6** presents the scope, costs and benefits of the credible options;
- **Chapter 7** details the assessment approach that AusNet and United Energy have employed for this RIT-T assessment, as well as the materiality of specific categories of market benefits;
- **Chapter 8** presents the results of the net present value analysis for each option and identifies the proposed preferred option and its optimal timing, along with scenario and sensitivity analysis results to confirm the robustness of the proposed preferred option to credible changes in assumptions; and
- **Chapter 9** presents the conclusions of the PADR, details of the proposed preferred option, and next steps.

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[8] National Electricity Rules, version 227, Australian Energy Market Commission (AEMC), 2025.
[9] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER).
[10] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.
[11] Transmission Connection Planning Report, Victorian Distribution Network Service Providers, 2024.

2. Description of the identified need

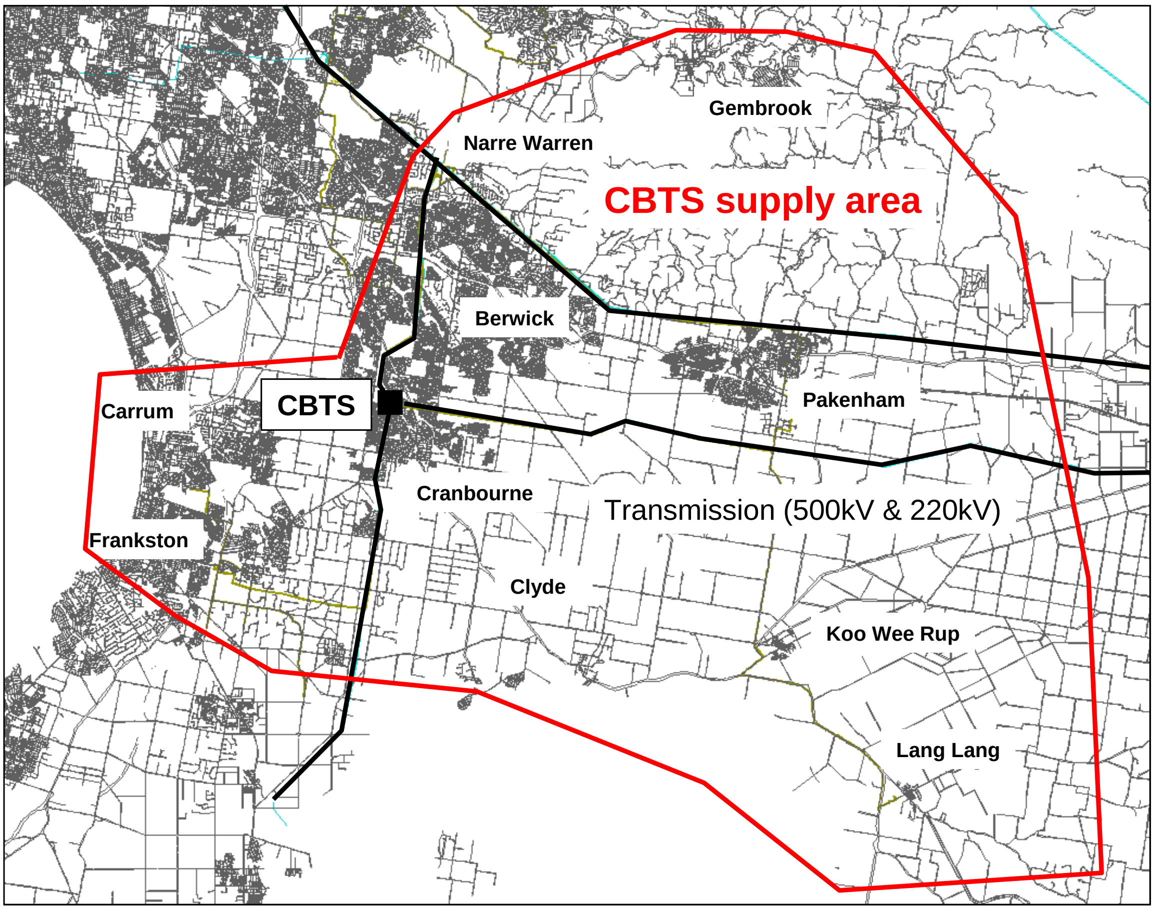
This chapter discusses the role of Cranbourne Terminal Station (CBTS) in providing electricity network services and the identified need associated with its current and forecast capacity limitations. Quantification of the risk and costs associated with the forecast increase in expected unserved energy (EUE) for the status-quo is also presented.

2.1. Cranbourne supply area

CBTS is the only terminal station that supplies the Cranbourne area and its surrounds. CBTS was originally established with two 150 MVA 220/66 kV transformers as a new terminal station in 2005 to reinforce the electricity network for the Cranbourne supply area, serviced by East Rowville Terminal Station (ERTS) at the time. In 2009, a third 150 MVA 220/66 kV transformer was commissioned at CBTS to supply further growth of electricity demand in the area which has subsequently materialised.

The geographic coverage of the Cranbourne supply area serviced by CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west, as shown in Figure 1. The electricity distribution networks for this area are the responsibility of both AusNet (63%) and United Energy (37%), based on annual energy supplied.

Figure 1: Cranbourne terminal station (CBTS) supply area



2.1.1. Customer demand for electricity

More than 198,000 customers[12] rely on CBTS for their electricity supply. Growth in customer numbers in the supply area has been substantial over the last several years, given CBTS services Melbourne's outer south-eastern growth corridor. Customer number growth has averaged at 5,600 additional customers per annum since 2014, an average annual increase of 3.6 per cent.

Residential customers consume 49.5 per cent of the total annual energy supplied from CBTS as listed in Table 2. This is closely followed by commercial customers, consuming 42.1 per cent of the total annual energy supplied.

Table 2: CBTS net energy consumption composition

CUSTOMER TYPE	SHARE OF CONSUMPTION (%)
Residential	49.5
Commercial	42.1
Industrial	6.1
Agricultural	2.4
Total	100

CBTS is a summer-peaking terminal station. Electricity demand at CBTS has been amongst the fastest growing in Victoria, and CBTS has reached its full capacity. The summer peak demand at CBTS increased by 172 MVA between 2007-08 and 2019-20, equivalent to an average annual growth rate of 4.1 per cent. In 2023-24, the summer maximum demand on CBTS reached 503.2 MW (519.4 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 601 MVA and 563 MVA respectively. Section 5.2.2 provides an overview of the maximum demand forecasts that underpin the identified need.

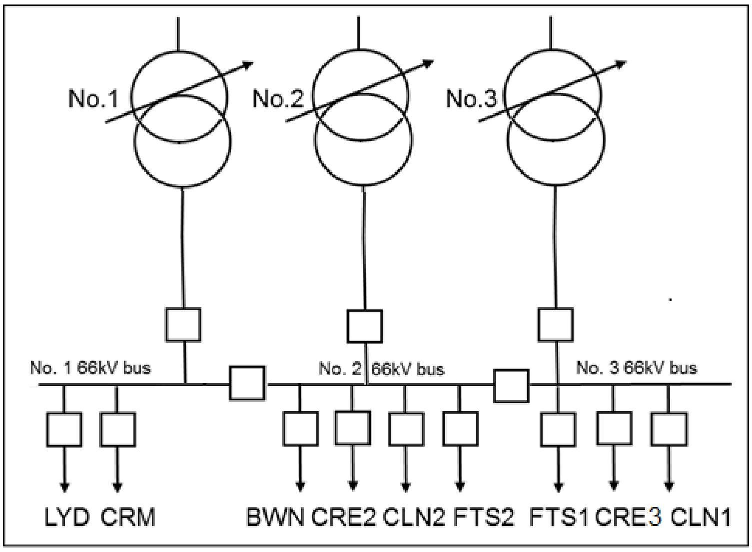
2.1.2. Electricity network servicing the supply area

CBTS currently has three parallel 150 MVA 220/66 kV transformers and three 66 kV buses. A simplified single line diagram of CBTS is provided in Figure 2.

The summer cyclic rating of CBTS with all plant in service is 553 MVA at 35°C and 540 MVA at 40°C. This rating is expected to be exceeded in 2025-26 for the POE50 and POE10 forecast summer maximum demands[13].

The summer cyclic rating of CBTS with one of its three transformers out of service, reduces to 369 MVA at 35°C and 360 MVA at 40°C and this rating is expected to be exceeded every year from now.

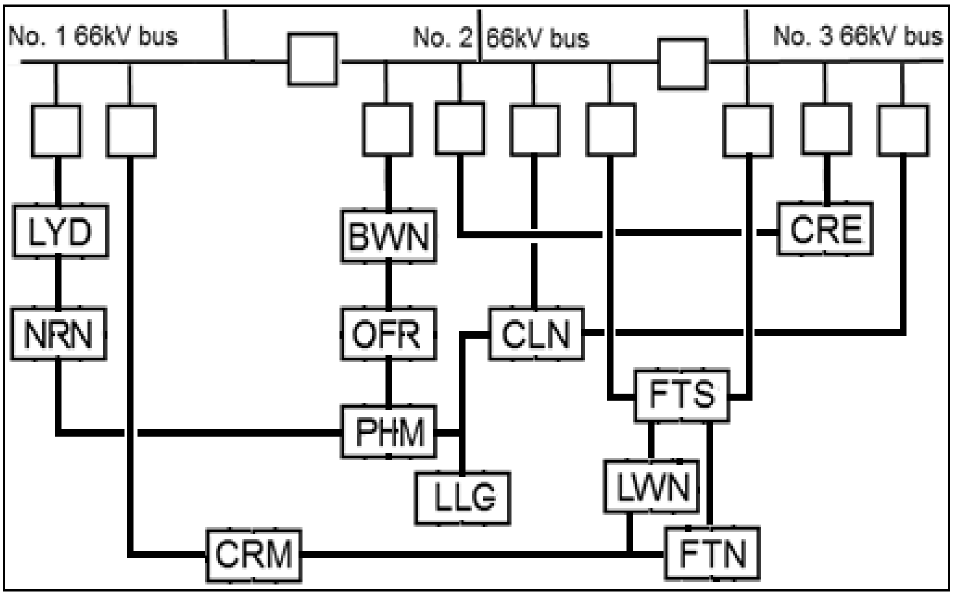
Figure 2: CBTS existing transmission connection assets single line diagram



[12] Total CBTS customer numbers in 2023-24.
[13] 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.

CBTS has nine 66 kV sub-transmission line exits supplying eight AusNet zone substations, Cranbourne (CRE), Lysterfield (LYD), Narre Warren (NRN), Pakenham (PHM), Officer (OFR), Berwick North (BWN), Lang Lang (LLG) and Clyde North (CLN), and three United Energy zone substations, Carrum (CRM), Langwarrin (LWN) and Frankston (FTN) in a loop via Frankston Terminal Station (FTS), which is only a 66 kV switching station with no transformation capacity. This is shown schematically in Figure 3.

Figure 3: CBTS existing sub-transmission network schematic diagram



As of 2024, about 380.2 MW of embedded generation capacity is installed on the distribution systems serviced by CBTS, including:

- about 244.8 MW of rooftop solar PV installed on the AusNet distribution system and about 105.2 MW of rooftop solar PV installed on the United Energy distribution system. This includes all the residential and small commercial rooftop PV systems that are smaller than 1 MW; and
- 30.2 MW capacity of large-scale embedded generation installed on the United Energy distribution system.

2.2. Identified need

There is forecast to be insufficient capacity to supply the forecast maximum demand at CBTS with the existing transmission connection assets that are in place under system normal conditions by 2025-26. Under single contingency conditions, there is already load at risk based on POE50 and POE10 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 Cranbourne supply area, and inhibit the connection of new customers.

The maximum demand growth in the CBTS 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 development of light industrial areas; and
- electrification of gas and transport sectors of society, associated with the energy transition.

The identified need is to deliver market benefits from reduced expected unserved energy (EUE) by maintaining electricity supply reliability for customers supplied from CBTS.

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 CBTS - 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 CBTS. The underlying maximum demand forecasts are shown in section 5.2.2.

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

YEAR[14]	POE10		POE50		PROBABILITY WEIGHTED[15]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	47.3	9	0.0	0	22.7	1.00
2026	61.2	11	9.6	1	67.4	2.98
2027	75.6	13	24.8	2	151.4	6.70
2028	92.1	16	40.2	2	264.2	11.70
2029	108.3	19	55.8	5	378.9	16.78
2030	123.6	22	71.0	9	527.6	23.37
2031	140.8	26	87.0	14	757.5	33.55
2032	159.5	29	104.3	19	1,068.8	47.25
2033	178.8	32	122.4	28	1,468.4	65.84
2034	196.5	35	138.7	36	1,956.2	86.64

There is forecast to be insufficient capacity to supply the growing demand at CBTS from 2025-26 under system normal ("N") operating conditions for a POE10 and POE50 forecast summer maximum demand.

By 2026-27 the 'N' EUE is estimated to be 151.42 MWh and have a value to consumers of around $6.70 million (real, 2025). The risk rises rapidly thereafter with an 'N' EUE in 2033-34 of approximately 1,956.2 MWh with a value of $86.64 million (real, 2025).

Table 4 provides a summary of the forecast "N-1" single contingency condition capacity limitations at CBTS (i.e., excluding the "N" system normal limitations presented above). The underlying maximum demand forecasts are shown in section 5.2.2.

[14] Financial year ending 30th June.
[15] 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.

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

YEAR[16]	POE10		POE50		PROBABILITY WEIGHTED[17]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	180.0	107	180.8	132	16.0	0.71
2026	180.0	151	184.0	161	19.6	0.87
2027	180.0	222	184.0	223	25.2	1.12
2028	180.0	307	184.0	303	33.5	1.48
2029	180.0	383	184.0	388	43.9	1.95
2030	180.0	480	184.0	482	56.7	2.51
2031	180.0	581	184.0	615	72.8	3.23
2032	180.0	726	184.0	764	94.4	4.18
2033	180.0	870	184.0	948	120.3	5.33
2034	180.0	1,031	184.0	1,156	149.4	6.62

The historical and forecast maximum demand under a transformer outage ("N-1") has exceeded the cyclic rating of CBTS every year since 2011-12, with levels of "N-1" load-at-risk during peak loading periods reaching the full transformer capacity of 184 MVA from 2025-26 for a POE50 forecast maximum demand. For an outage of one 220/66 kV transformer at CBTS, there will be insufficient capacity at this terminal station to supply all demand at the POE10 forecast maximum demand for about 151 hours in 2025-26, and 161 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, contributing to an expected unavailability per transformer per annum of 0.22 per cent.

CBTS has load transfer capability available at both the 22 kV distribution feeder level and at the 66 kV sub-transmission level. This capability allows AusNet and United Energy to manage risk in the short-term, by transferring load away from CBTS to surrounding terminal stations using spare capacity available through each distribution network.

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 19.6 MWh in 2025-26. This EUE is estimated to have a value to consumers of around $0.87 million (real, 2025). By 2026-27 this increases to 25.2 MWh and $1.12 million (real, 2025), and by 2033-34 this increases to 149.4 MWh and $6.62 million (real, 2025).

The estimates of EUE and its financial value assume 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 $44,292/MWh.

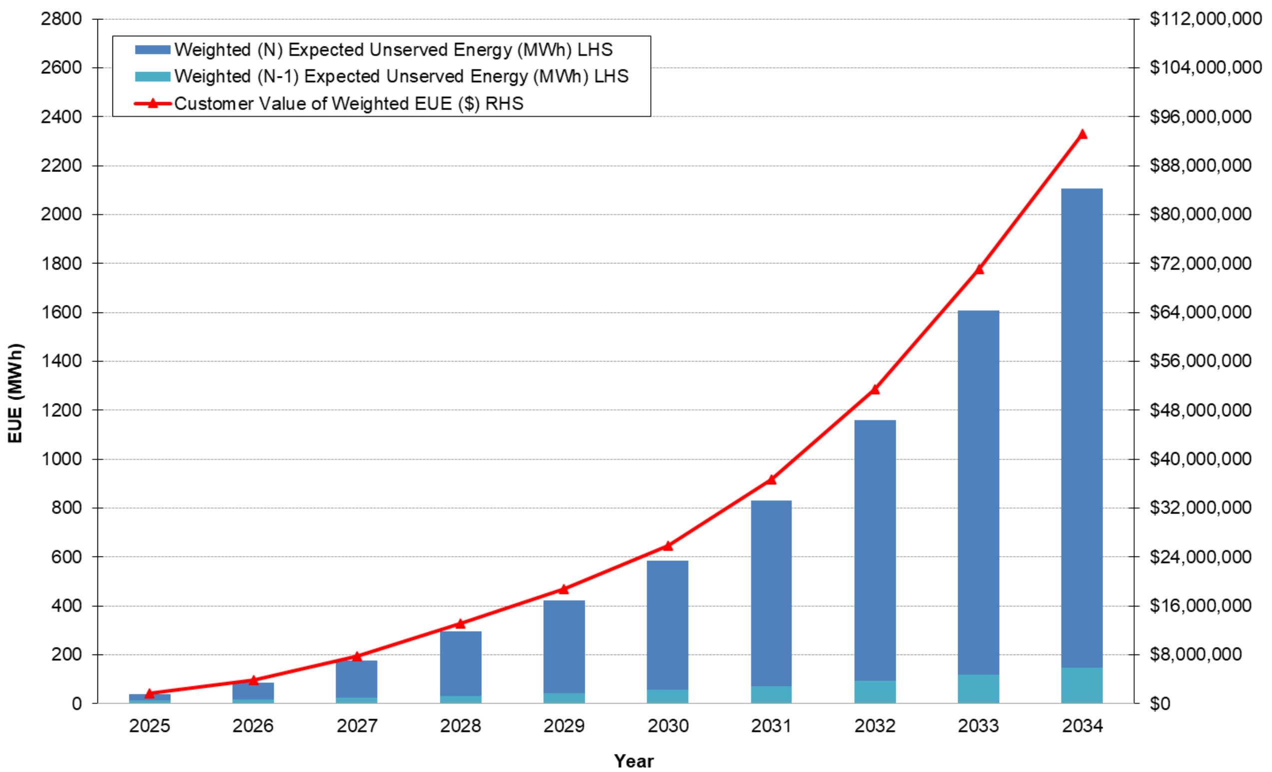
The key elements of the "Do Nothing" supply reliability risk under the status-quo are shown in Table 5 and Figure 4 for both "N" and "N-1" conditions, including the risk-reduction effects of available load transfer capability.

[16] Financial year ending 30th June.
[17] 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.

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

YEAR[18]	PROBABILITY WEIGHTED[19]		YEAR	PROBABILITY WEIGHTED	
	EUE (MWh)	EUE Cost ($ million)		EUE (MWh)	EUE Cost ($ million)
2025	38.6	1.71	**2030**	584	25.9
2026	86.9	3.85	**2031**	830	36.8
2027	177	7.82	**2032**	1,161	51.4
2028	298	13.2	**2033**	1,607	71.2
2029	423	18.7	**2034**	2,106	93.3

Figure 4: CBTS EUE risk costs (taking account of available load transfer capability)



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

By undertaking one of the options identified in this RIT-T, AusNet and United Energy will be able to avoid this projected deterioration in supply reliability for the Cranbourne supply area.

[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.

3. Credible options assessed

This chapter identifies credible options that aim to address the identified need.

The credible options assessed to address the identified need for the Cranbourne supply area include:

- **Option 1 - Do nothing (base case)** continues to supply customers serviced by CBTS without any intervention (apart from load transfer options – i.e., the status-quo) to manage increasing EUE levels. It is used as a comparison case to which all other credible options will be compared, to identify the option that maximises the present value of net economic benefit;
- **Option 3 - Install a fourth 150 MVA 220/66 kV transformer at CBTS** to increase the thermal capacity of the CBTS transmission connection assets to address the identified need. There is already provision to accommodate a fourth transformer at CBTS, and would involve a fourth 66 kV bus and rearrangements of the existing 66 kV sub-transmission feeders within the terminal station;
- **Option 4 - Install two 50 MVAr 66 kV capacitor banks at CBTS** (followed by Option 3) to reduce the net maximum demand on CBTS to address the identified need. There is provision to accommodate capacitor banks at CBTS, and would involve extension of the 66 kV buses within the terminal station; and
- **Option 5 - Establish new 22 kV distribution feeders to offload CBTS** (followed by Option 3) in order to maintain the maximum demand on CBTS within its "N" rating and to maintain its present load transfer capability to address the identified need. There is opportunity to establish new 22 kV distribution feeders from United Energy's Mordialloc and Frankston South zone substations, located just outside of the supply area, to offload CBTS.

The following options were considered but not progressed as credible options in this PADR:

- **Option 2 - Non-network or SAPS solutions** is to contract network support services, within the distribution networks serviced by CBTS, to reduce the net maximum demand on CBTS and address the identified need. Network support services could include services such as voluntary load reduction (e.g., demand response), aggregated distributed energy resources (e.g., virtual power plants), or larger-scale dispatchable embedded storage and/or generation resources;
- **Option 6 - Establish a new 220/66 kV terminal station in the Pakenham area** (site yet to be identified) to reduce the maximum demand on CBTS, transferring load to the new terminal station by re-arranging the existing sub-transmission network, thereby addressing the identified need. This is the most expensive credible option.

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

The PSCR flagged Option 3 as the preferred *network* option that maximises the net market benefits, to be confirmed in this PADR.

4. Submissions to the consultation

This chapter provides a summary of, and commentary on, the submissions to the PSCR consultation.

In October 2024, AusNet and United Energy published the project specification consultation report (PSCR), being the first stage of this RIT-T process, which provided an opportunity for non-network providers to submit proposals for alternative solutions to address the identified need.

During this period of consultation on the PSCR, no non-network proposals or submissions were received from interested stakeholders.

As a consequence, Option 2 from the PSCR (i.e., non-network or SAPS solutions) is no longer considered a credible option for the purposes of this PADR in addressing the identified need of the Cranbourne supply area.

Furthermore, as the capital cost of the preferred network option is greater than the trigger threshold of $54 million[20] for publication of a project assessment draft report, we are undertaking a second round of consultation for this RIT-T by publishing this PADR.

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

5. Assumptions used in identifying the identified need

This chapter details the assumptions used in identifying the identified need.

First, we set out the probabilistic planning approach applied by AusNet and United Energy in planning the network, in the context of our overall approach to the net present value (NPV) analysis under the RIT-T. Chapter 7 then provides further detail on key assumptions that AusNet and United Energy have adopted for this stage of the RIT-T.

5.1. Overview of approach to the NPV analysis

Consistent with the RIT-T NER requirements[21], cost benefit analysis guidelines[22] and RIT-T application guidelines[23], AusNet and United Energy 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 7.

In planning the network, AusNet and United Energy 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 United Energy have taken 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 of this 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.

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.

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[21] Regulatory investment test for transmission, Australian Energy Regulator, 21 November 2024.
[22] Cost Benefit Analysis guideline, Australian Energy Regulator, 21 November 2024.
[23] RIT-T application guideline, Australian Energy Regulator, 21 November 2024.

5.2. 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) information.

5.2.1. Network asset ratings

The capability of the transmission connection assets at CBTS is limited by the thermal cyclic rating of its three parallel 220/66 kV 150 MVA transformers. Table 6 provides a summary of the capability of CBTS for "N" and "N-1" conditions during summer and winter (maximum demand) seasons.

Table 6: CBTS thermal capacity cyclic ratings (MVA)

SEASON	EXISTING	
	"N"	"N-1"
Summer 35 Degrees Celsius	553	369
Summer 40 Degrees Celsius	540	360
Winter 15 Degrees Celsius	630	413

Section 6.3 shows how these thermal capacity ratings would be expected to increase following the implementation of the proposed preferred *network* option.

5.2.2. Forecast maximum demand

The forecast maximum demand at CBTS 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[24]. Table 7 provides a summary of the forecast maximum demand for CBTS during summer and winter (maximum demand) seasons.

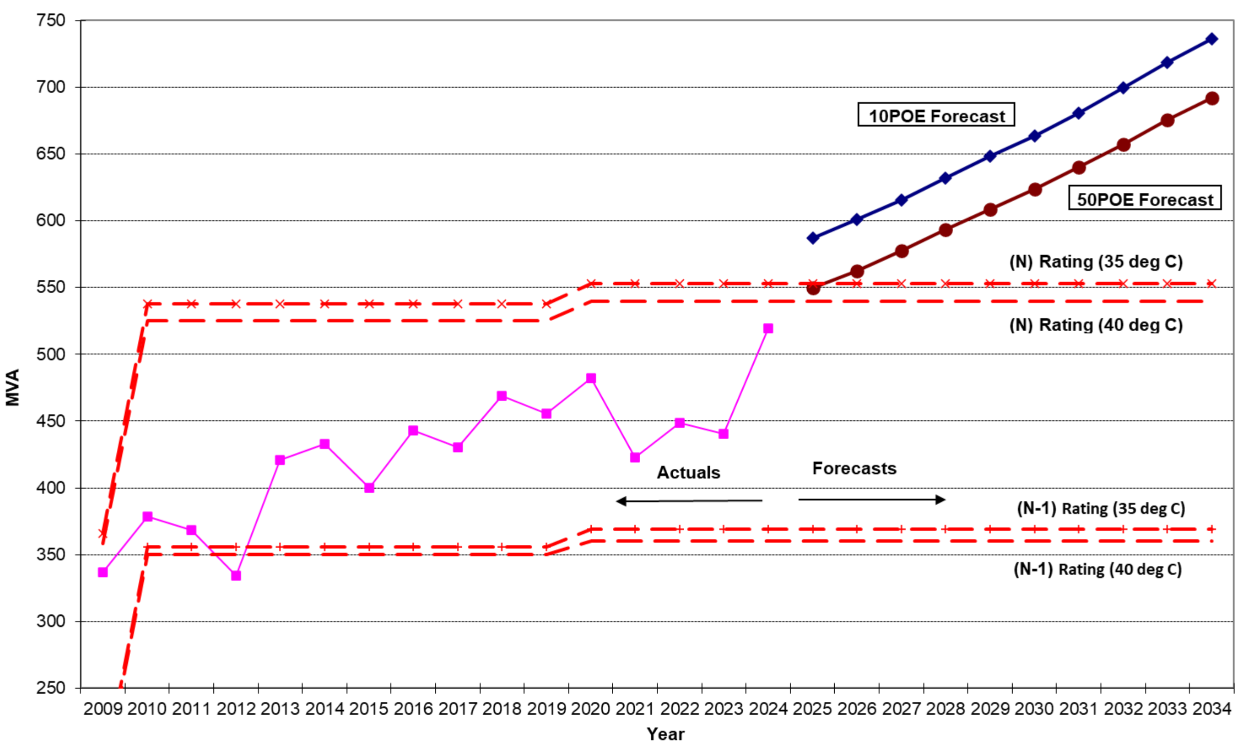
[24] Victorian electricity demand is sensitive to ambient temperature. Maximum demand forecasts are therefore based on expected demand during extreme temperature that could occur once every ten years (POE10) and during average conditions that could occur every second year (POE50).

Table 7: CBTS forecast maximum demand (MVA)

YEAR[25]	MAXIMUM DEMAND SEASON AND POE			
	Summer POE10	Winter POE10	Summer POE50	Winter POE50
2025	587	435	550	407
2026	601	449	563	431
2027	616	464	578	447
2028	632	482	593	463
2029	648	500	609	481
2030	664	516	624	496
2031	681	532	640	512
2032	699	548	657	528
2033	719	566	675	545
2034	736	583	692	562

Figure 5 shows the POE10 and the POE50 forecasts maximum demand for CBTS during summer periods relative to its capacity.

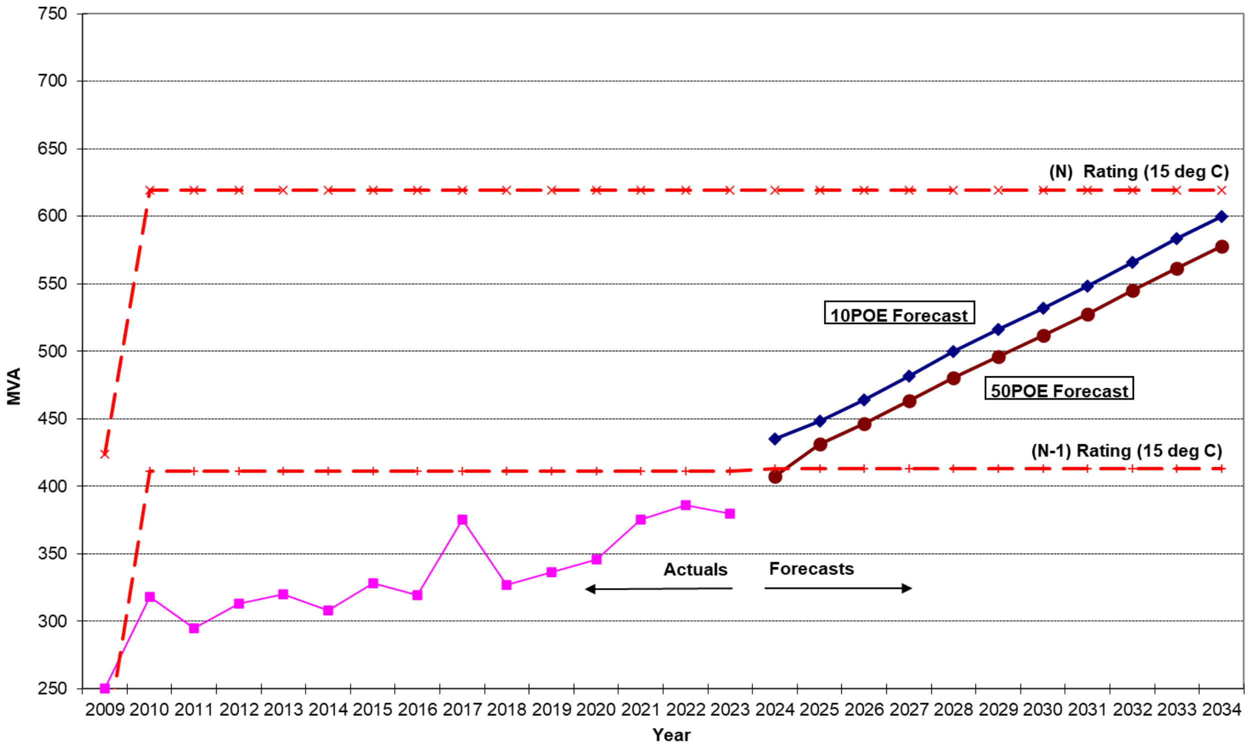
Figure 5: Summer period maximum demand forecasts for CBTS



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

Figure 6 shows the POE10 and the POE50 forecast maximum demand for CBTS during winter periods relative to its capacity.

Figure 6: Winter period maximum demand forecasts for CBTS



The maximum demand growth in the CBTS 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 development of light industrial areas; and
- electrification of gas and transport sectors of society, associated with the energy transition.

The maximum demand forecasts used in this PADR were prepared in early 2025.

5.2.3. Load transfer capability

Based on the present POE10 maximum demand, there is the capacity to transfer 81 MVA of load to East Rowville Terminal Station (ERTS) via the sub-transmission network without overloading ERTS. It does come with significant operational risks though because it would require AusNet to split its meshed sub-transmission network into radial lines, and would therefore only be utilised to manage the risk of an “N-1” post-contingency overload at CBTS – that is, an interruption to supply will occur before the transfer can be enacted. To manage “N” overload risk at CBTS, there is 13 MVA of 22 kV distribution feeder transfers available on the AusNet distribution network from CBTS to ERTS.

Furthermore, there is the capacity to transfer 100 MVA of load to Tyabb Terminal Station (TBTS) and 79 MVA to Heatherton Terminal Station (HTS) via the sub-transmission network without overloading TBTS and HTS. Again, it does come with significant operational risks because it would require United Energy to split its meshed sub-transmission network into radial lines, and would therefore only be utilised to manage the risk of an “N-1” post-contingency overload at CBTS. To manage “N” overload risk at CBTS, there is 22 MVA of 22 kV distribution feeder transfers available on the United Energy distribution network from CBTS – to ERTS, HTS and TBTS.

The total combined 66 kV sub-transmission line transfer capability to manage the “N-1” post-contingency risk in 2024-25 was 260 MVA. This is limited by the ratings of the sub-transmission lines providing the transfer capacity.

The total combined 22 kV distribution feeder transfer capability to manage the “N” risk in 2024-25 was 35 MVA. This is limited by the peak utilisation on the adjacent distribution feeders providing the transfer capacity, and will therefore deteriorate over time as utilisation on these feeders increase.

Table 8 provides a summary of the forecast load transfer capability away from CBTS to minimise EUE.

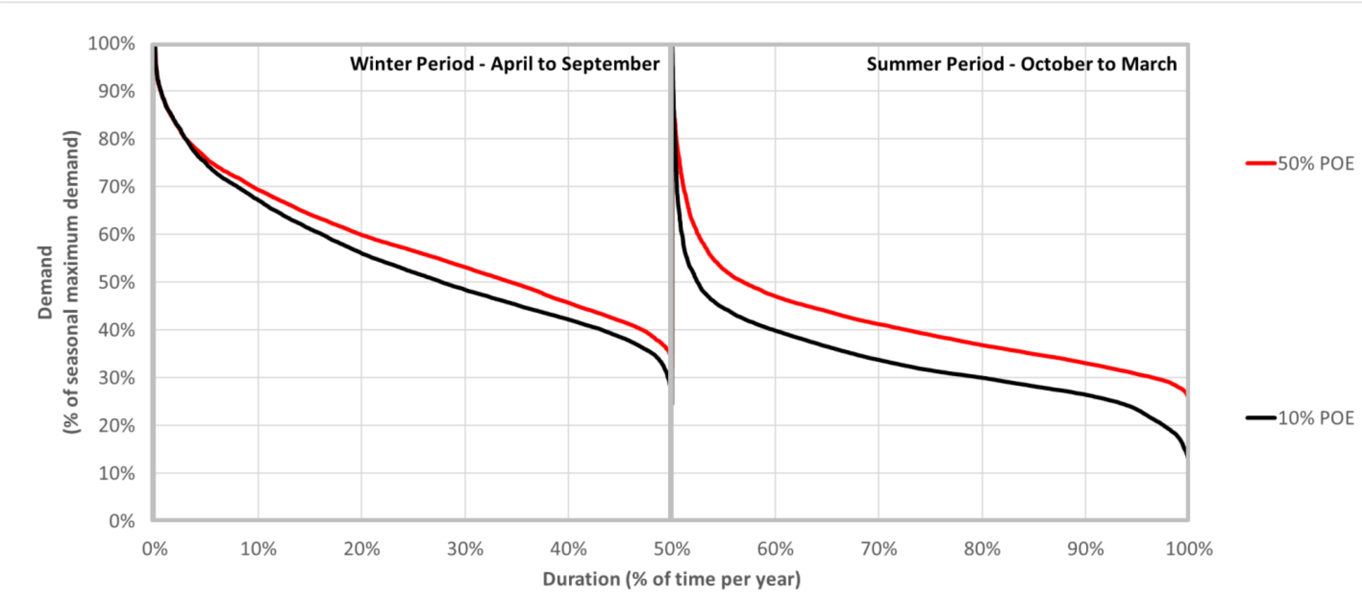
Table 8: CBTS available transfer capability (MVA)

YEAR[26]	LOAD TRANSFER CAPABILITY (MVA)	
	Distribution to manage "N" risk	Sub-Transmission to manage "N-1" risk[27]
2025	35	260
2026	25	260
2027	15	260
2028	5	260
2029	0	260
2030	0	260
2031	0	260
2032	0	260
2033	0	260
2034	0	260

5.2.4. 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 CBTS. Underlying load is used as the basis on which to calculate EUE for this report. The underlying load-duration curves for CBTS for POE10 and POE50 maximum demands are shown in Figure 7. The shape of the curves are strongly influenced by the coincidence of extreme ambient temperature on working weekdays and the number of times this occurs in any one year.

Figure 7: Load-duration profile for CBTS

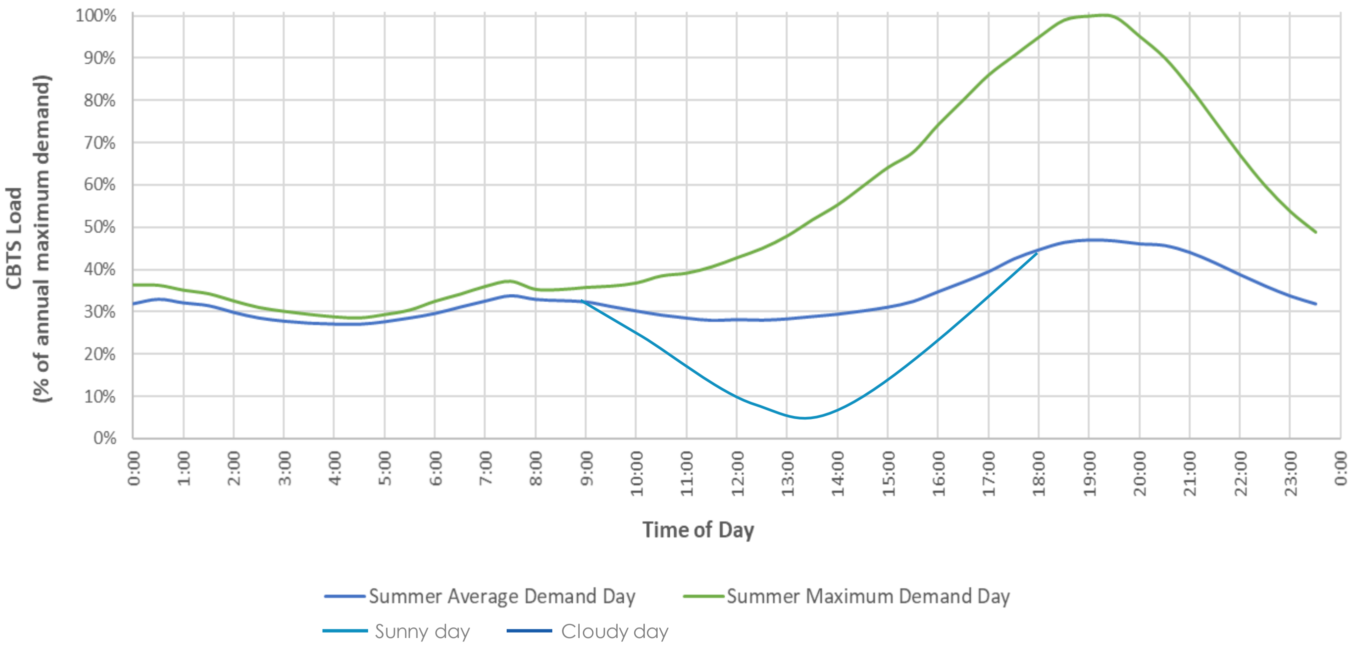


[26] Financial year ending 30th June.
[27] Sub-transmission level transfers are only available for use under "N-1" post-contingency conditions due to topology limitations within the sub-transmission networks. Therefore, an outage will be experienced prior to implementing the transfers.

Approximately 244.8 MW of rooftop solar PV is now installed on the AusNet distribution system and about 105.2 MW of rooftop solar PV is installed on the United Energy distribution system connected to CBTS. This includes all the residential and small commercial rooftop PV systems smaller than 1 MW. In addition, there is 30.2 MW capacity of large-scale embedded generation installed on the United Energy distribution system connected to CBTS.

The typical net daily load profiles at CBTS during the summer season are shown in Figure 8.

Figure 8: Daily load profile for CBTS (summer season)



5.2.5. Network asset reliability

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

Table 9: CBTS transformer reliability information[28]

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.

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

6. Credible options costs and benefits

This chapter presents the scope, costs and benefits of the credible options.

6.1. Option 1 – Do nothing

The "Do nothing" option continues to supply customers serviced by CBTS without any investments to manage increasing EUE levels, utilising only the available load transfer capability to manage the risk (i.e., the 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 CBTS.

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 4), is forecast to increase from $1.71 million in 2024-25 to $7.82 million in 2026-27, to $93.3 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 implemented under the "Do nothing" option, the "Do nothing" option is considered a zero-cost and zero-benefit option.

6.2. Option 2 – Non-network or SAPS solutions

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

In October 2024, AusNet and United Energy published the project specification consultation report (PSCR), being the first stage of this RIT-T process which provided an opportunity for non-network providers to submit proposals for alternative solutions to address the identified need.

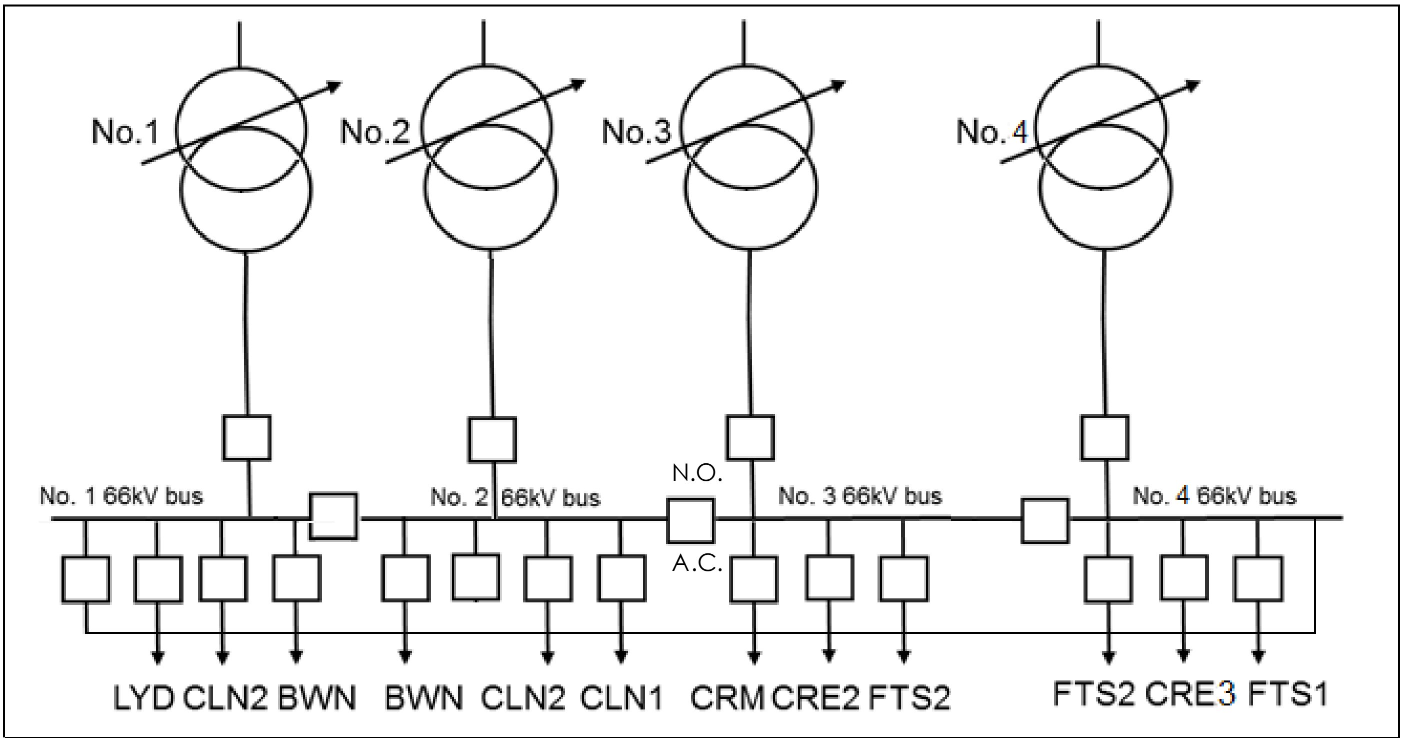
During this period of consultation on the PSCR, no non-network proposals or submissions were received from interested stakeholders.

As a consequence, this option has been considered but not progressed on the basis that it is not a credible option for the purposes of addressing the identified need for this RIT-T.

6.3. Option 3 - Install a 4th 220/66 kV transformer at CBTS

This option involves installing a fourth 150 MVA 220/66 kV 150 MVA transformer at CBTS 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 fourth transformer. The scope of works would also involve installing a fourth 66kV bus with a ring connection, and rearrangements of the existing 66 kV sub-transmission feeders within the terminal station to allow CBTS to operate with the 66 kV bus split into a B12 and a B34 group, so that maximum short circuit levels can be maintained within safe levels. The simplified single line diagram is shown in Figure 9.

Figure 9 – CBTS proposed transmission connection assets single line diagram (Option 3)



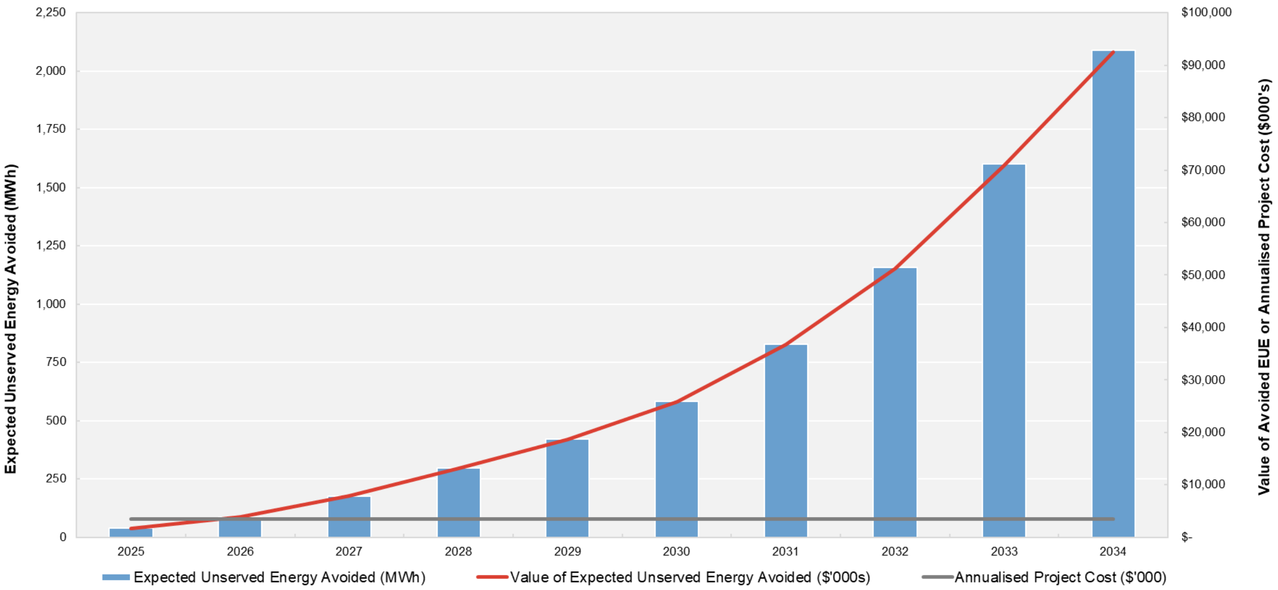
The scope of work required for this option includes:

- a new fourth 150 MVA 220/66 kV transformer to the west of the existing transformers, including firewalls;
- a new 220 kV circuit breaker, bay and rack;
- extending the No.1 66 kV bus with two new circuit breakers and establish a new No.4 66 kV bus with five new 66 kV circuit breakers;
- a neutral earth reactor at the new fourth transformer 66 kV neutral that matches the neutral earth reactors at all existing transformers;
- a new auto-reclose scheme, which will provide for parallel operation of three transformers in the event of a transformer or bus outage;
- a new 66 kV ring bus to link the No.1 and No.4 66 kV bus;
- relocation of AusNet and United Energy 66 kV feeder exits as shown in Figure 9 with BWN, LYD, CLN loops on 1-2 bus (B12) group and CRE, FTS, CRM on 3-4 bus (B34) group. Three feeders (BWN, CLN2 and FTS2) are to be double switched; and
- replacement of line protection at CRE and CLN to match new line double-switched protection at CBTS.

The estimated capital cost of this network option is $56.0 million (real, 2025) which has a present value of $55.1 million and an annualised cost of $3.4 million (includes $0.5 million of operating and maintenance costs per annum).

The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing for the fourth transformer of summer 2025-26. This is shown in Figure 10.

Figure 10 – Option 3 optimal timing based on avoided risks and annualised costs



This option has a typical construction timetable of approximately two to three years. However with an expedited construction plan, the works can be completed by summer 2026-27.

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.

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

Table 10: CBTS thermal capacity cyclic ratings if Option 3 is implemented (MVA)

SEASON	POST OPTION 3	
	"N"	"N-1"
Summer 35 Degrees Celsius	369 B12 369 B34	553
Summer 40 Degrees Celsius	360 B12 360 B34	540
Winter 15 Degrees Celsius	413 B12 413 B34	630

Table 11 lists the forecast "N" system normal limitations at CBTS with Option 3 in service, based on its optimum timing.

Table 11 - CBTS capacity limitations with Option 3 in service (EUE for "N" condition)

YEAR[29]	POE10		POE50		PROBABILITY WEIGHTED[30]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*47.3*	*9*	*0.0*	*0*	*22.7*	*1.00*
2026	*61.2*	*11*	*9.6*	*1*	*67.4*	*2.98*
2027[31]	*0.0*	*0*	*0.0*	*0*	*0.0*	*0.00*
2028	0.0	0	0.0	0	0.0	0.00
2029	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00
2033	0.0	0	0.0	0	0.0	0.00
2034	16.5	3	0.0	0	9.4	0.42

Table 12 lists the forecast "N-1" contingency limitations at CBTS (i.e., excluding the "N" system normal limitations presented above) with Option 3 in service, based on its optimum timing.

Table 12 - CBTS capacity limitations with Option 3 in service (EUE for "N-1" condition)

YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*180.0*	*107*	*180.8*	*132*	*16.0*	*0.71*
2026	*180.0*	*151*	*184.0*	*161*	*19.6*	*0.87*
2027[32]	*75.6*	*13*	*24.8*	*2*	*0.6*	*0.03*
2028	92.1	16	40.2	2	0.9	0.04
2029	108.3	19	55.8	5	1.2	0.06
2030	123.6	22	71.0	9	1.7	0.08
2031	140.8	26	87.0	14	2.5	0.11
2032	159.5	29	104.3	19	3.5	0.16
2033	178.8	32	122.4	28	4.9	0.22
2034	180.0	35	138.7	36	6.4	0.28

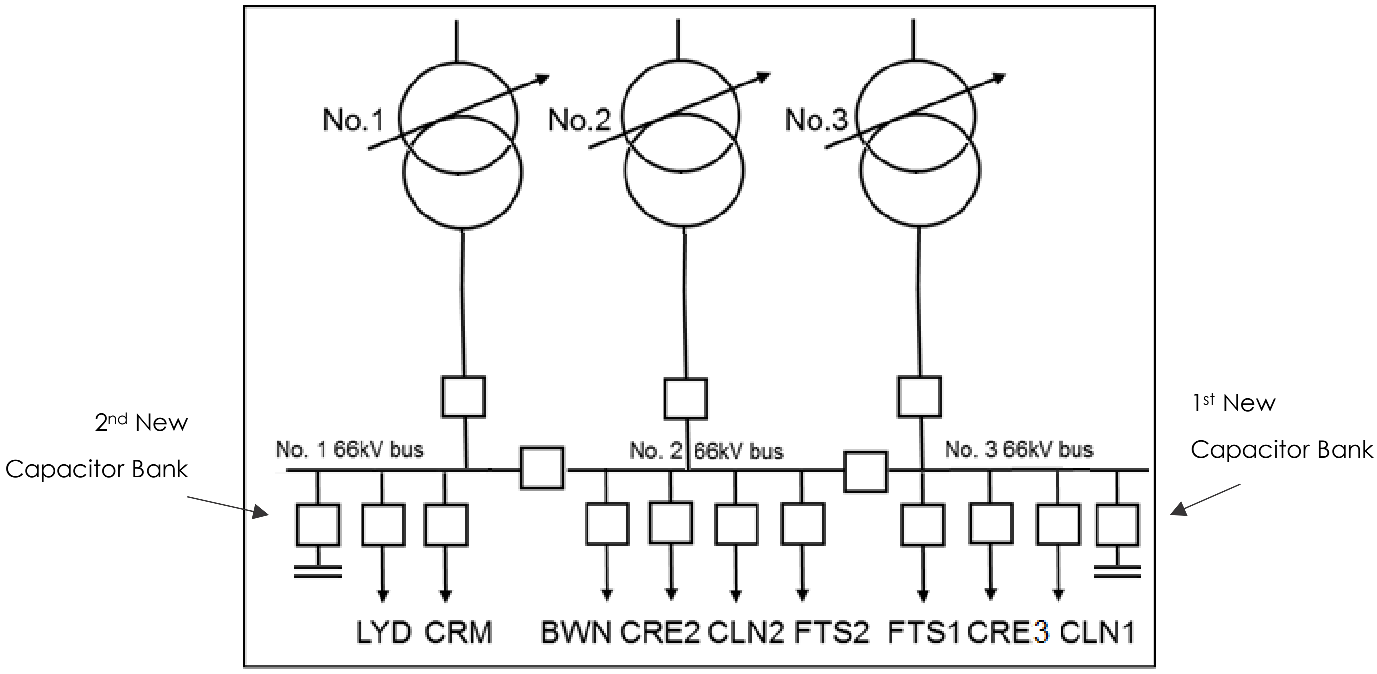
This option meets the identified need by alleviating the load at risk and removing a majority of the EUE at CBTS, after installation of the fourth transformer at CBTS, over the next ten years.

[29] Financial year ending 30th June.
[30] 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.
[31] Fourth transformer in service.
[32] Fourth transformer in service.

6.4. Option 4 - Install two 50 MVAr 66 kV capacitor banks

This option involves installing two 50 MVAR 66 kV capacitor banks to reduce the net maximum demand on CBTS and delay the identified need, followed by Option 3. There is provision to accommodate capacitor banks at CBTS and this would involve extension of the existing 66 kV buses within the terminal station as shown in Figure 11.

Figure 11 – CBTS proposed transmission connection assets single line diagram (Option 4)



Currently, CBTS operates at a power factor of approximately 0.97 lagging in summer and does not have any 66 kV capacitor banks. Two switched 50 MVAR 66 kV capacitor banks installed will reduce POE10 maximum demand by approximately 15 MVA and may defer the preferred network option (Option 3) by one year given the average growth rate is around this level.

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.

The estimated incremental capital cost of the two capacitor banks is $9.0 million (real, 2025), bringing the total capital cost of this option to $65.0 million. The total present value capital cost of this network option, including the deferred installation of the fourth transformer, is $61.2 million, and has an annualised cost of $4.0 million (includes $0.6 million of operating and maintenance costs per annum).

The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentations), provides an optimal timing for the fourth transformer of summer 2026-27 as shown in Figure 12.

This option has a typical construction timetable of two to three years, therefore the earliest possible commissioning is 2027-28, with the two new 66 kV capacitor banks in service by 2026-27 providing the one-year deferral of the transformer.

Figure 12 – Option 4 optimal timing based on avoided risks and annualised costs

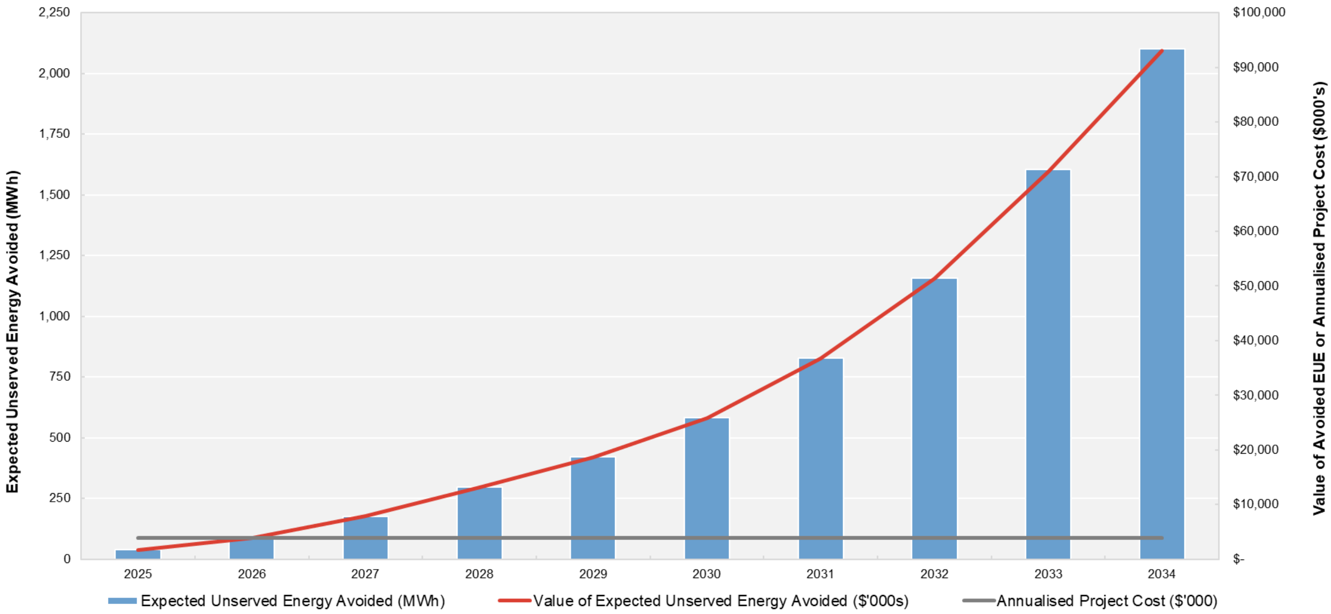


Table 13 lists the forecast "N" system normal limitations at CBTS with Option 4 in service, based on its optimum timing.

Table 13 - CBTS capacity limitations with Option 4 in service (EUE for "N" condition)

YEAR[33]	POE10		POE50		PROBABILITY WEIGHTED[34]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*47.3*	*9*	*0.0*	*0*	*22.7*	*1.00*
2026	*61.2*	*11*	*9.6*	*1*	*67.4*	*2.98*
2027[35]	*57.9*	*10*	*8.3*	*1*	*82.8*	*3.67*
2028[36]	0.0	0	0.0	0	0.0	0.00
2029	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00
2033	0.0	0	0.0	0	0.0	0.00
2034	0.0	0	0.0	0	0.0	0.00

[33] Financial year ending 30th June.
[34] 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.
[35] New 66 kV capacitor banks in service.
[36] Fourth transformer in service.

Table 14 lists the forecast "N-1" contingency limitations at CBTS (i.e., excluding the "N" system normal limitations presented above) with Option 4 in service, based on its optimum timing.

Table 14 - CBTS capacity limitations with Option 4 in service (EUE for "N-1" condition)

YEAR[37]	POE10		POE50		PROBABILITY WEIGHTED[38]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*180.0*	*107*	*180.8*	*132*	*16.0*	*0.71*
2026	*180.0*	*151*	*184.0*	*161*	*19.6*	*0.87*
2027[39]	180.0	191	184.0	187	20.7	0.92
2028[40]	74.2	13	23.4	2	0.5	0.02
2029	90.1	16	38.8	2	0.8	0.04
2030	105.2	19	53.8	4	1.2	0.05
2031	122.2	22	69.5	8	1.7	0.07
2032	140.6	26	86.6	14	2.5	0.11
2033	159.7	29	104.3	19	3.5	0.16
2034	177.2	32	120.4	27	4.7	0.21

This option meets the identified need by alleviating the load at risk and removing a majority of the EUE at CBTS, after installation of the fourth transformer at CBTS, over the next ten years.

[37] Financial year ending 30th June.
[38] 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.
[39] New 66 kV capacitor banks in service.
[40] Fourth transformer in service.

6.5. Option 5 - Establish new feeders to offload CBTS

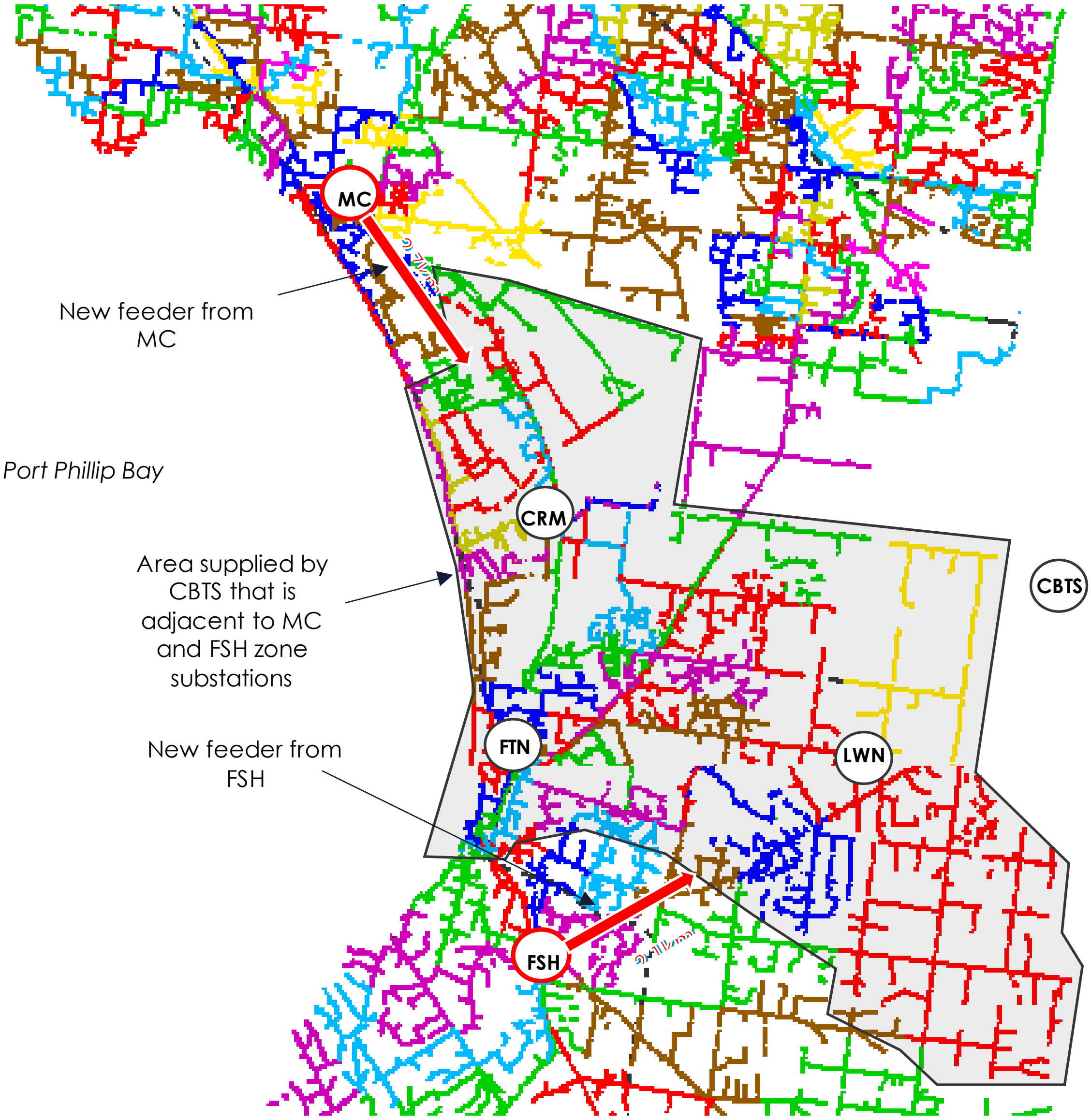
This option involves establishing two new 22 kV distribution feeders to offload CBTS in order to maintain the maximum demand on CBTS within its "N" rating and to maintain its present load transfer capability to address the identified need as shown in Figure 13, followed by Option 3.

There is opportunity to establish two new 22 kV distribution feeders from United Energy's Mordialloc (MC) and Frankston South (FSH) zone substations, located adjacent to the Cranbourne supply area. These zone substations, supplied by Heatherton Terminal Station (HTS) and Tyabb Terminal Station (TBTS) respectively, have spare capacity to offload parts of zone-substations CRM and LWN, which are both currently supplied from CBTS.

In total this option requires the establishment of 2.7 km of 22 kV underground cable for the new MC distribution feeder and 2.1 km of 22 kV underground cable for the new FSH feeder, as well as the zone substation works including new circuit breakers, protection and control equipment.

Establishing these two feeders will allow up to 26 MVA of load to be offloaded from CBTS and could defer the preferred network option (Option 3) by at least one year.

Figure 13 – Proposed new distribution feeders to offload CBTS (Option 5)



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 low profile power lines and underground cabling within existing road reserves and easements. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

The estimated incremental capital cost of the new 22 kV feeders is $9.5 million (real, 2025), bringing the total capital cost of this option to $65.5 million. The total present value capital cost of this network option, including the deferred installation of the fourth transformer, is $61.7 million, and has an annualised cost of $4.0 million (includes $0.6 million of operating and maintenance costs per annum).

The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing for the fourth transformer of summer 2026-27 as shown in Figure 14.

This option has a typical construction timetable of two to three years, therefore the earliest possible commissioning is 2027-28, with the two new 22 kV feeders in service by 2026-27 providing the one-year deferral of the transformer.

Figure 14 – Option 5 optimal timing based on avoided risks and annualised costs

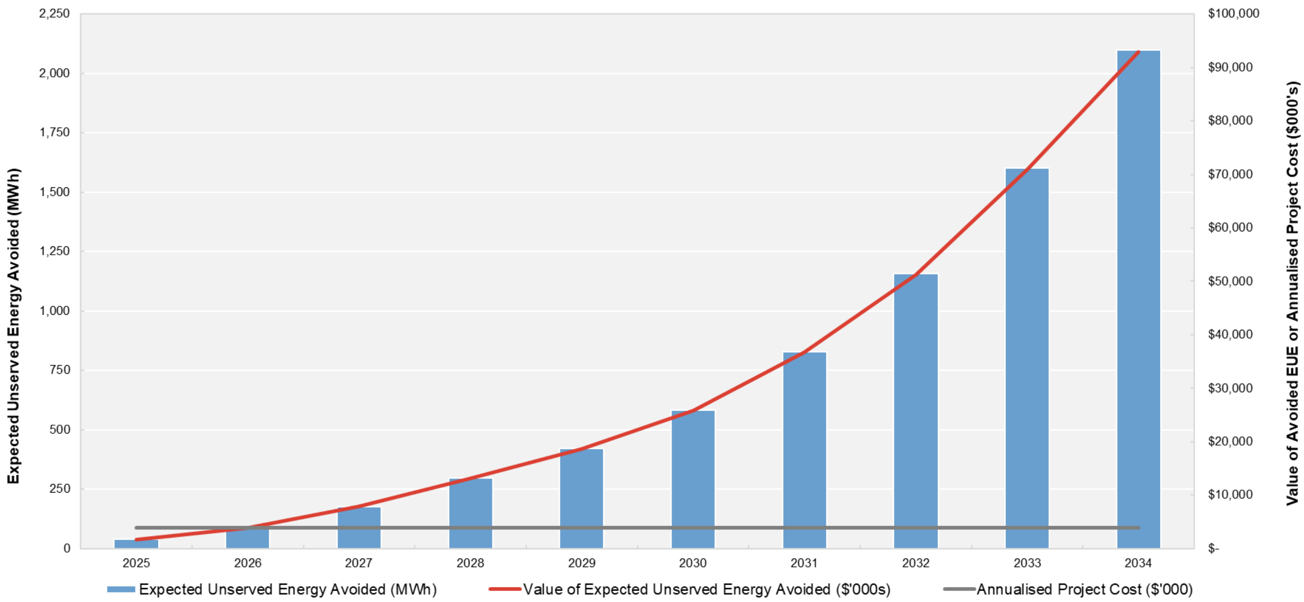


Table 15 lists the forecast "N" system normal limitations at CBTS with Option 5 in service, based on its optimum timing.

Table 16 lists the forecast "N-1" contingency limitations at CBTS (i.e., excluding the "N" system normal limitations presented above) with Option 5 in service, based on its optimum timing.

Table 15 - CBTS capacity limitations with Option 5 in service (EUE for "N" condition)

YEAR[41]	POE10		POE50		PROBABILITY WEIGHTED[42]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*47.3*	*9*	*0.0*	*0*	*22.7*	*1.00*
2026	*61.2*	*11*	9.6	*1*	*67.4*	2.98
2027[43]	75.6	13	24.8	2	69.3	3.07
2028[44]	0.0	0	0.0	0	0.0	0.00
2029	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00
2033	0.0	0	0.0	0	0.0	0.00
2034	16.5	3	0.0	0	0.8	0.03

Table 16 - CBTS capacity limitations with Option 5 in service (EUE for "N-1" condition)

YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*180.0*	*107*	*180.8*	*132*	*16.0*	*0.71*
2026	*180.0*	*151*	*184.0*	*161*	*19.6*	*0.87*
2027[45]	180.0	222	184.0	223	25.2	1.12
2028[46]	92.1	16	40.2	2	0.9	0.04
2029	108.3	19	55.8	5	1.2	0.06
2030	123.6	22	71.0	9	1.7	0.08
2031	140.8	26	87.0	14	2.5	0.11
2032	159.5	29	104.3	19	3.5	0.16
2033	178.8	32	122.4	28	4.9	0.22
2034	180.0	35	138.7	36	6.4	0.28

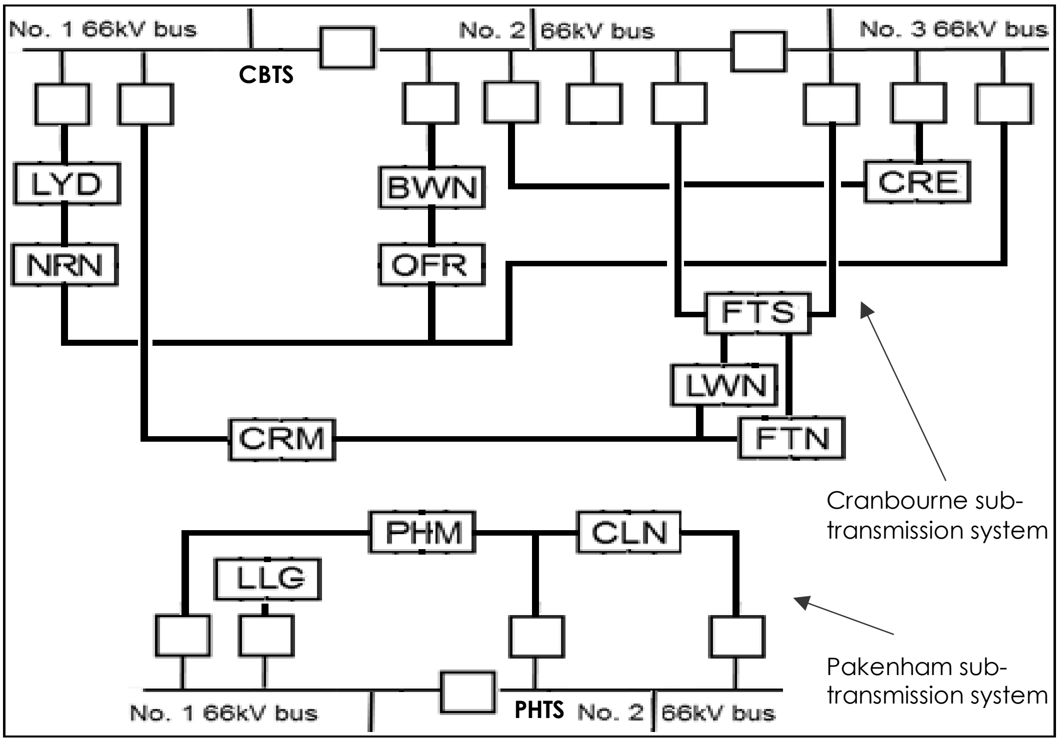
This option meets the identified need by alleviating the load at risk and removing a majority of the EUE at CBTS, after installation of the fourth transformer at CBTS, over the next ten years .

[41] Financial year ending 30th June.
[42] 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.
[43] New 22 kV feeders in service.
[44] Fourth transformer in service.
[45] New 22 kV feeders in service.
[46] Fourth transformer in service.

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

This option establishes a new 220/66 kV terminal station in the Pakenham area (site yet to be identified) to reduce the maximum demand on CBTS, 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 zone substations PHM, CLN and LLG to the new terminal station, as shown in Figure 15.

Figure 15 – Possible sub-transmission network schematic diagram (Option 6)



This option is by far the most expensive option with a total estimated capital cost of $250 million (real, 2025) which, has a present value capital cost of $211 million, and has an annualised cost of $14.4 million (includes $1.2 million of operating and maintenance costs per annum).

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

Social licencing risks are considered major for this option and will increase over time as the surrounding area becomes increasingly urbanised. The option involves work to procure land and establish a new terminal station, and establishing low profile power lines within existing road reserves and new easements, to connect into the existing distribution network. The site would be procured next to an existing transmission corridor, so that only existing transmission line cut-ins through the future site are required, with no new transmission lines or extensions required. Extensive community consultation 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.

The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing for the new terminal station of summer 2028-29 as shown in Figure 16.

Figure 16 – Option 6 optimal timing based on avoided risks and annualised costs

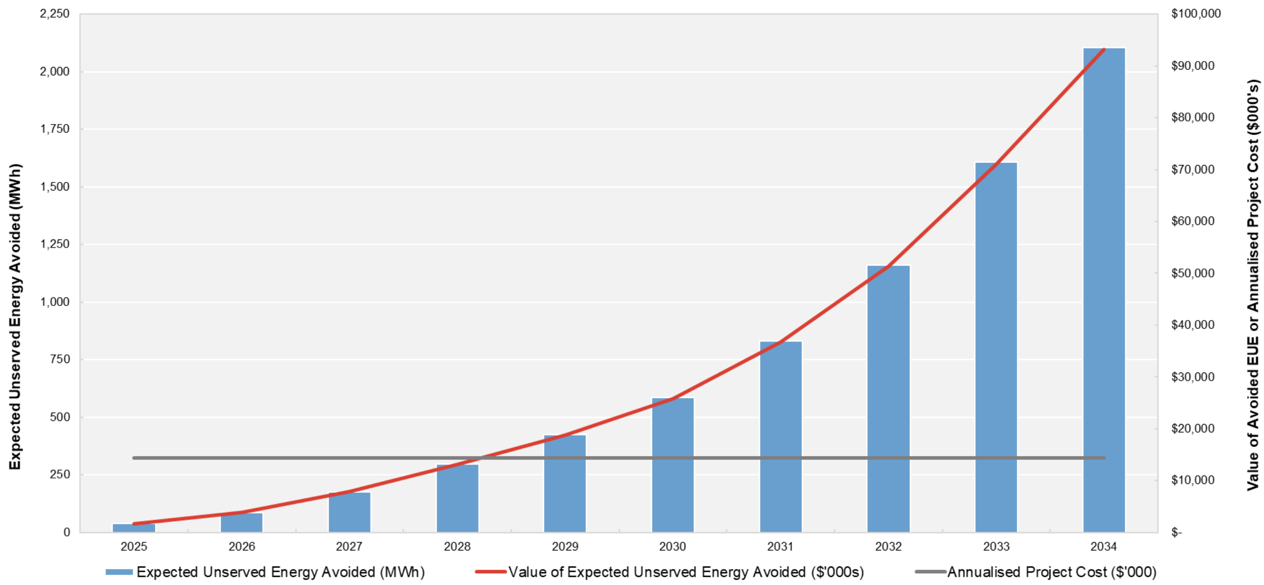


Table 17 lists the forecast "N" system normal limitations at CBTS with Option 6 in service, based on its optimum timing.

Table 17 - CBTS capacity limitations with Option 6 in service (EUE for "N" condition)

YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*47.3*	*9*	*0.0*	*0*	*22.7*	*1.00*
2026	*61.2*	*11*	*9.6*	*1*	*67.4*	*2.98*
2027	*75.6*	*13*	*24.8*	*2*	*151.4*	*6.70*
2028	*92.1*	*16*	*40.2*	*2*	*264.2*	*11.70*
2029[47]	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00
2033	0.0	0	0.0	0	0.0	0.00
2034	0.0	0	0.0	0	0.0	0.00

[47] New terminal station in service.

Table 18 lists the forecast "N-1" contingency limitations at CBTS with Option 6 in service, based on its optimum timing.

Table 18 - CBTS capacity limitations with Option 6 in service (EUE for "N-1" condition)

YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2025	*180.0*	*107*	*180.8*	*132*	*16.0*	*0.71*
2026	*180.0*	*151*	*184.0*	*161*	*19.6*	*0.87*
2027	*180.0*	*222*	*184.0*	*223*	*25.2*	*1.12*
2028	*180.0*	*307*	*184.0*	*303*	*33.5*	*1.48*
2029[48]	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00
2033	0.0	0	0.0	0	0.0	0.00
2034	0.0	0	0.0	0	0.0	0.00

When commissioned, this option meets the identified need by alleviating the supply capacity risk and removing all the expected unserved energy over the next 10 years. However there is significant unmitigated risk in the years prior.

This option has been considered but not progressed on the basis that it cost prohibitive and cannot meet the identified need in time, given the construction timetable for this option is four to five years and no site has been procured to accommodate the new terminal station.

[48] New terminal station in service.

7. Assessment methodology

This chapter discusses the 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.

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7.1. Assessment parameters

7.1.1. 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 United Energy have applied locational VCR values based on the Australian Energy Regulator's (AER) Values of Customer Reliability Review published in December 2024. Applying the AER's sector VCRs to terminal station level historical energy composition data from 2023-24, a CBTS VCR of $44,292/MWh was derived, as presented in Table 19.

Table 19: CBTS value of customer reliability

SECTOR	AER VCR ($/MWH)[49]	CBTS ENERGY CONSUMPTION BY SECTOR	CBTS WEIGHTED VCR ($/MWH)
Residential[50]	55,100	49.5%	27,253
Commercial	34,390	42.1%	14,474
Industrial	33,490	6.1%	2,040
Agricultural	22,250	2.4%	525
Composite		**100%**	**44,292**

7.1.2. Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. A real, 5.0 per cent, discount rate is applied at CBTS, as the central assumption to the cost-benefit assessments presented in this report.

The 7.0 per cent discount rate in AEMO's 2023 inputs, assumptions and scenarios report[51] (IASR) is used in the high bound sensitivity test in the PADR. For the low bound sensitivity test we use a 3.0 per cent discount rate.

7.1.3. Assessment period

It is necessary to apply a cost-benefit analysis assessment period commensurate with the options being evaluated to address the identified need. The RIT-T analysis has been undertaken over a 20-year period as the central assumption in this PADR, with a terminal value included in the final year representing the net value of the asset over its remaining asset life. Monetised risks are capped to their year 10 values from year 11 to the end of the evaluation period.

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[49] AER 2024 published VCRs. Climate zone 6 applies at CBTS.
[50] Suburban classification.
[51] 2023 Inputs, Assumptions and Scenarios Report, Table 31, AEMO July 2023.

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 Cranbourne supply area intended to be addressed by the credible options in this RIT-T.

7.1.4. Approach to estimating option costs

The costs for each option have been calculated by AusNet'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.

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

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

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

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

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

7.2. 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:[52]

- 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.

AusNet and United Energy estimate that the following classes of market benefits are unlikely to be material for any of the options considered in this RIT-T:

- **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).

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

- **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.

7.3. Sensitivity studies

The robustness of the investment decision is tested using the range of input assumptions described in Table 20. This analysis varies the assumptions used for the central case as detailed in section 5.2.

Table 20 - Input assumptions used for the sensitivity studies

PARAMETER	LOWER BOUND	CENTRAL CASE	HIGHER BOUND
Capital and Operating Costs	70% of the option's total cost	100% of the option's total cost	130% of the option's total cost
Maximum demand forecast	90% of TCPR 2024 maximum demand	100% of TCPR 2024 maximum demand	105% of TCPR 2024 maximum demand
Asset failure rate	80% of central	100% of central	120% of central
Value of customer reliability	80% of AER VCRs - site specific for CBTS	100% of AER VCRs - site specific for CBTS	120% of AER VCRs - site specific for CBTS
Discount rate	3.0% - regulatory discount rate	5.0% - commercial discount rate	7.0% - AEMO 2023 IASR
Asset life	20 years	45 years	60 years

7.4. Scenario modelling to address uncertainty

The RIT-T analysis is required to incorporate a number of different reasonable scenarios, which are used to estimate the benefits and rank options. The number and choice of reasonable scenarios must be appropriate to the credible options under consideration and reflect any variables or parameters that are likely to affect the ranking or sign of the net economic benefit of any credible option.

The assessment for this PADR was conducted under three future-state scenarios by choosing the parameters in Table 20 with high uncertainty, as follows:

- **Central scenario** - adopting the central assumptions in Table 20;
- **Low scenario** – adopting lower bound demand, failure rates and VCR; and
- **High scenario** – adopting higher bound demand, failure rates and VCR.

These are plausible scenarios which reflect different assumptions about the future energy landscape and other factors that are expected to affect the relative market benefits of the options considered. In Table 21, the reasoning for selecting these parameters is provided as well as the weighting applied to each future-state scenario to reflect the likelihood of each scenario, based on currently available information. A heavier weighting is applied to the low scenario compared to the high scenario to reflect the current uncertainty and volatility in the global economy and its potential moderating effect on electricity maximum demand growth.

Table 21 – Parameters with high uncertainty used for scenario modelling

PARAMETER	REASONING	LOW	CENTRAL	HIGH
Weighting		**35%**	**50%**	**15%**
Maximum demand forecast	Over the last decade there was significant uncertainty in forecasting maximum demand. Factors including economic growth, retail electricity prices, gas electrification and uptake of distributed energy resources (including rooftop solar, batteries and electric vehicles) have contributed to the uncertainty. Uncertainty is expected to remain high over the planning horizon in each of these areas.	Lower Bound	Central Case	Higher Bound
Asset failure rate	Transformers have a very high reliability and long technical life, meaning their forced outage rates are highly uncertain, being dependent on a range of technical and environmental operating factors. With increasing condition monitoring, changes in technology and climate change, historical failure rates may not be reflective of future performance.	Lower Bound	Central Case	Higher Bound
Value of customer reliability	Variability in the valuation of customer reliability between VCR surveys demonstrates a need to consider future changes in the VCR in the analysis. Furthermore, with the changes in the way customers are using electricity and adopting storage solutions, this is likely to impact the value that customers place on supply reliability.	Lower Bound	Central Case	Higher Bound

8. Options assessment

This chapter presents the results of the net present value analysis for each option and identifies the proposed preferred option and its optimal timing, along with scenario and sensitivity analysis results to confirm the robustness of the proposed preferred option to credible changes in assumptions.

8.1. Gross market benefits

All the options considered in this RIT-T assessment address the identified need to varying extents resulting in differing levels of gross benefits relative to the "Do Nothing" base case. The estimated present value of gross market benefits of each option is presented in Table 22 based on their optimal timing.

Table 22 – Calculated present value of gross benefits relative to base case ($ million, real 2025)

OPTION	LOW SCENARIO	CENTRAL SCENARIO	HIGH SCENARIO
Option 1	0	0	0
Option 3	190	1,164	2,856
Option 4	189	1,169	2,873
Option 5	190	1,170	2,873
Option 6	197	1,172	2,859

8.2. Capital and operating costs

The estimated present value of capital, operating and maintenance costs of each option relative to the "Do Nothing" base case is presented in Table 23 based on their based on their optimal timing.

Table 23 – Calculated present value of capital and operating costs relative to base case ($ million, real 2025)

OPTION	LOW SCENARIO	CENTRAL SCENARIO	HIGH SCENARIO
Option 1	0	0	0
Option 3	(55.1)	(55.1)	(55.1)
Option 4	(61.2)	(61.2)	(61.2)
Option 5	(61.7)	(61.7)	(61.7)
Option 6	(211.1)	(211.1)	(211.1)

8.3. Present value of net economic benefits

The estimated present value of net economic benefits of each option relative to the "Do Nothing" base case, being the present value of gross benefits minus the present value of capital and operating costs, is presented in Table 24 based on their optimal timing.

Table 24 – Calculated present value of net economic benefits relative to base case ($ million, real 2025)

OPTION	LOW SCENARIO	CENTRAL SCENARIO	HIGH SCENARIO	WEIGHTED SCENARIO	
Weighting	**35%**	**50%**	**15%**	**100%**	**Rank**
Option 1	0	0	0	0	5
Option 3	135	1,109	2,801	1,022	1
Option 4	128	1,108	2,812	1,021	2
Option 5	128	1,108	2,811	1,020	3
Option 6	(14)	961	2,648	873	4

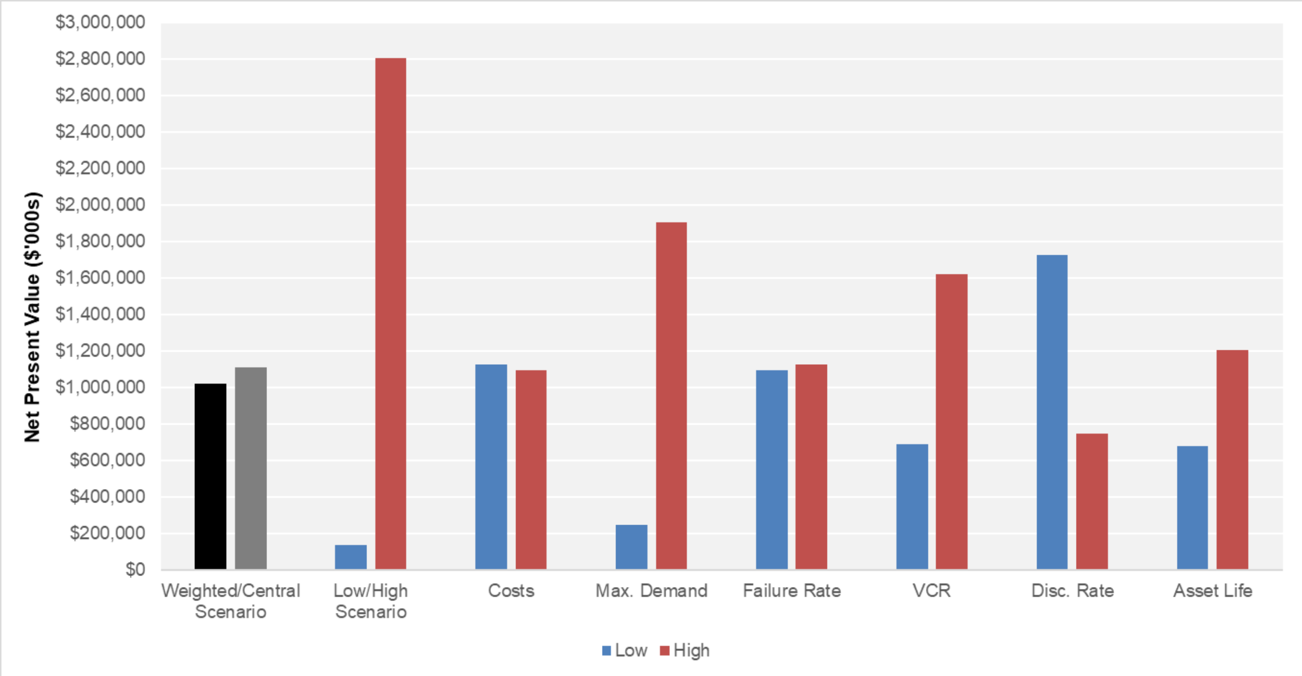
8.4. Proposed preferred option

Our analysis has found that Option 3 (i.e., Install fourth 220/66 kV transformer at CBTS) is the proposed preferred option as it is the option that maximises the present value of net market benefits under the weighted scenario.

AusNet and United Energy have assessed that the additional cost of investing in the network assets required for Options 4 and 5 to defer Option 3 is not warranted, given they do not provide net market benefits in excess of those of the proposed preferred option for the weighted scenario.

The robustness of the proposed preferred option's net economic benefits to credible variations in key parameters (in Table 20), is demonstrated in the sensitivity study results of Figure 17.

Figure 17 – NPV sensitivity analysis of the proposed preferred option ($ thousand, real 2025)



Under all credible sensitivities, the net present value of benefits remains positive for Option 3.

Option 3 satisfies the requirements of the RIT-T.

8.5. Optimal timing of the proposed preferred option

This section identifies and tests the robustness of the optimal timing of Option 3 for different assumptions of key parameters as detailed in Table 20. The changes in timing away from the optimal timing of 2025-26 for each of the sensitivities, noting that the practical timing is 2026-27, is presented in Table 25.

Table 25 - Sensitivity of the optimal timing with respect to variation of key parameters

PARAMETER	LOWER BOUND	HIGHER BOUND
Capital and Operating Costs	2025-26 (no change)	2026-27 (1 year later)
Maximum demand forecast	2029-30 (4 years later)	2025-26 (no change)
Asset failure rate	2025-26 (no change)	2025-26 (no change)
Value of customer reliability	2026-27 (1 year later)	2025-26 (no change)
Discount rate	2025-26 (no change)	2026-27 (1 year later)
Asset life	2025-26 (no change)	2025-26 (no change)

The timing of the proposed preferred option is robust, varying in timing by up to one year in all but one sensitivity. All but one sensitivity provide an optimal timing within the practical timing of 2026-27. The timing risk around the maximum demand lower bound sensitivity has been mitigated in this RIT-T by placing an elevated weighting on the low scenario as discussed in section 7.4.

9. Draft conclusion and next steps

This chapter presents the draft conclusions of the PADR, details the proposed preferred option, and next steps.

9.1. Draft conclusion

The cost-benefit assessment undertaken for this PADR confirms that Option 3 (i.e., Install fourth 220/66 kV transformer at CBTS) is the proposed preferred option to meet the identified need. Option 3 is the proposed preferred option in accordance with NER clause 5.16.1(b) because it is the credible option that maximises the net present value of the net economic benefit. It therefore satisfies the RIT-T.

This option involves installing a fourth 220/66 kV 150 MVA transformer at CBTS to increase the thermal capacity cyclic 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 fourth transformer. The scope of works would also involve installing a fourth 66 kV bus, and rearrangements of the existing 66 kV sub-transmission feeders within the terminal station to allow CBTS to operate with the 66 kV bus split into a B12 and a B34 group so that maximum short circuit levels can be maintained within safe levels.

This proposed preferred option is found to have positive net benefits under all scenarios investigated and on a weighted scenario basis will deliver $1,022 million in net economic benefits over its lifecycle. A sensitivity analysis was conducted on the net economic benefit to investigate the robustness of the conclusion to credible variations in key assumptions. It was identified that under all sensitivities, positive net benefits are maintained.

The optimal timing of the proposed preferred option (limited by the expedited construction lead time) is 2026-27 based on an estimated capital cost of $56.0 million (real, 2025) with annual operating and maintenance costs relating to this investment of approximately $0.5 million.

9.2. Next steps

AusNet and United Energy invites written submissions and enquires on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "***Cranbourne Supply Area RIT-T***", and directed to both:

Dasun De Silva (AusNet)

Senior Manager, Network Development & Planning

Email: dasun.desilva@ausnetservices.com.au

and

Richard Robson (United Energy)

Manager Sub-transmission Planning and Major Connections

Email: ricrobson@powercor.com.au

The consultation on this PADR is open for 6 weeks, consistent with the NER requirements[53]. Submissions are due on or before 18th July 2025.

[53] NER, clause 5.16.4(r).

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

Following conclusion of the PADR consultation period, AusNet and United Energy will, having regard to any submissions received on the PADR, prepare and publish a project assessment conclusions report (PACR) including:

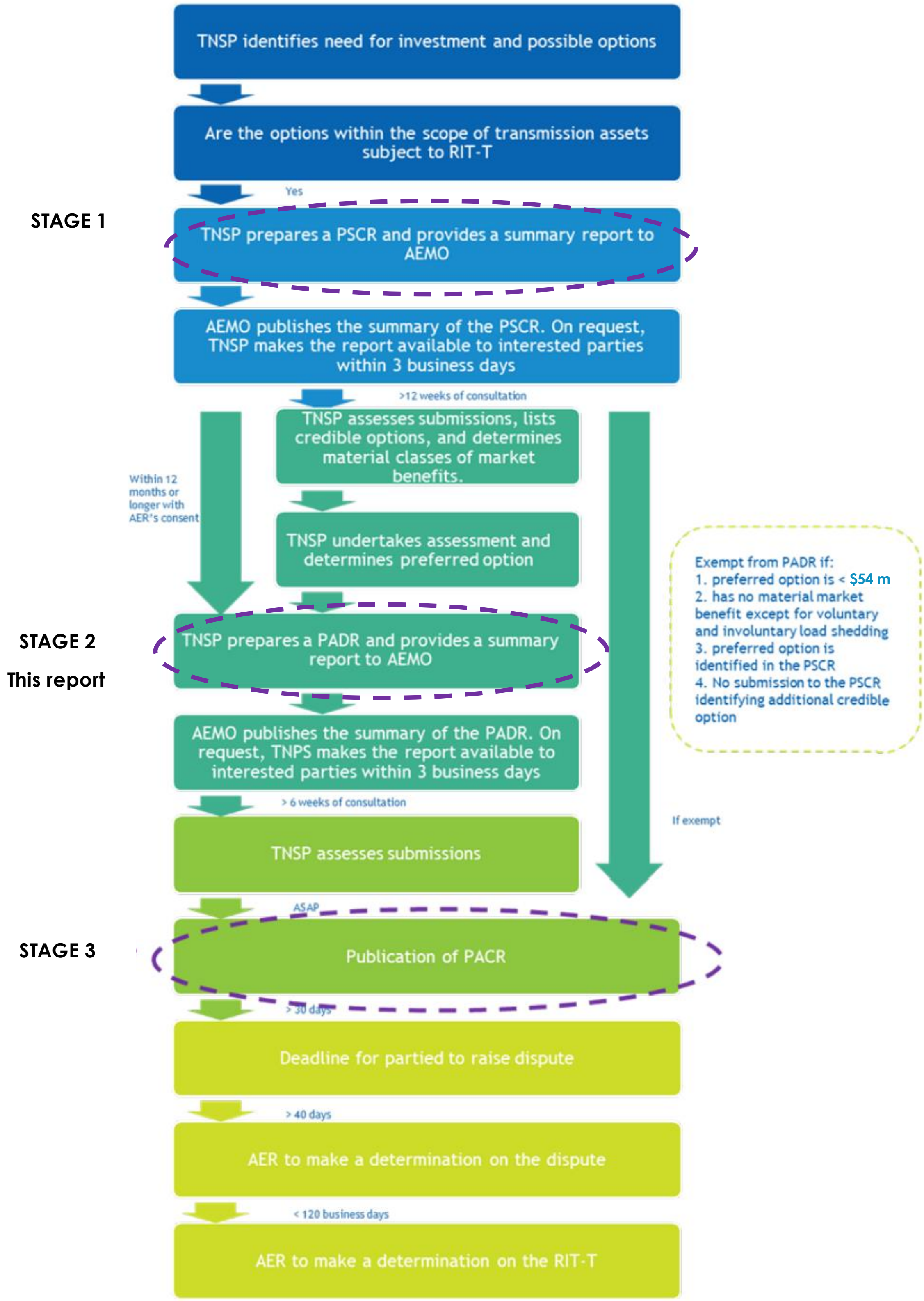
- a summary of, and commentary on, the submissions on the PADR;
- the matters detailed in the PADR; and
- confirming the preferred option to meet the identified need.

Publication of that report will conclude the RIT-T consultation.

AusNet and United Energy intend on publishing the PACR in the third quarter of 2025.

A. RIT-T assessment and consultation process

Figure 18: RIT-T Process



B. RIT-T compliance checklist

This appendix sets out a checklist in Table 26 which demonstrates the compliance of this PADR with the requirements of clause 5.16.4(k) of the NER version 227.

Table 26 – PADR RIT-T compliance checklist

A RIT-T PROPONENT MUST PREPARE A REPORT WHICH MUST INCLUDE:	CHAPTER
(1) a description of each credible option assessed;	Chapter 3
(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Chapter 4
(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	Chapter 6
(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	
(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Chapter 7
(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	
(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Chapter 8
(8) the identification of the proposed preferred option;	
(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i)details of the technical characteristics; (ii)the estimated construction timetable and commissioning date; (iii)if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv)a statement and the accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for transmission;	Chapter 9
(10) if each of the following apply to the RIT-T project: (i)the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and (ii)AEMO is not the sole RIT-T proponent, the RIT reopening triggers applying to the RIT-T project;	Not applicable

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