

RIT-T: Terang Supply Area – Project Assessment Conclusions Report

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Executive summary

Powercor Australia Ltd (Powercor) is a regulated Victorian electricity distribution network service provider (**DNSP**). We supply electricity across 64 per cent of Victoria from the western suburbs of Melbourne through central and western regional Victoria to the South Australian and New South Wales borders, servicing 945,000 customer connections. The network consists of more than 602,760 poles and over 77,438 kilometres of overhead lines and underground cables. Electricity is received via 138 sub-transmission lines at 155 zone substations, where it is transformed from sub-transmission voltages down to distribution voltages.

We aim to maintain service levels at the lowest possible cost for our customers. Achieving this requires assessment of options and development of plans that maximise the present value of net economic benefit. Where relevant, this includes preparation of, and consultation on, regulatory investment tests.

The regulatory investment test for transmission (**RIT-T**) is an economic cost-benefit test and consultation process used to assess and rank potential investments capable of meeting an identified need, in accordance with the requirements of clauses 5.15A and 5.16 of the *National Electricity Rules (NER)*¹. 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 identified need for this RIT-T is forecast transmission connection asset limitations at Terang Terminal Station (**TGTS**). TGTS is the major source of supply for the electricity distribution network in south-western Victoria. The limitations arise predominantly from forecast generation growth within the broader Terang supply area, impacting the reliability of supply to our customers.

In Victoria, the distributors have responsibility for planning and directing augmentation of the transmission connection assets that connect their distribution systems to the Victorian shared transmission system. This RIT-T is being undertaken by us (as the lead proponent of this RIT-T), in accordance with the requirements of the NER and section 4.4 of the *RIT-T Application Guidelines*².

This project assessment conclusions report (**PACR**) is the final stage of the RIT-T consultation process. This report confirms the preferred option to address the identified need for the Terang supply area.

Identified need

The identified need for this RIT-T is to maintain electricity supply reliability and mitigate growth in expected unserved energy (**EUE**) for customers serviced by TGTS.

TGTS is a 220/66 kV terminal station owned and operated by AusNet Transmission Group. The geographic area supplied by TGTS spans south-western Victoria from the South Australian border through Hamilton and as far east as Colac and Winchelsea. It serves towns along the Great Ocean Road and the major coastal city of Warrnambool.

TGTS serves 64,681 customers and is a major collector of power from grid-connected renewable generation in the area, particularly wind farms. A total of 489 MW of embedded generation capacity is installed or committed to be installed across the sub-transmission and distribution systems connected to TGTS. It consists of 346 MW of installed and 72 MW of committed large-scale embedded wind generation, and 71 MW of installed small-scale residential and commercial rooftop solar panels.

TGTS has a single 125 MVA transformer and a 150 MVA transformer. It has a system normal (**N**) rating of 275 MVA and a single contingency (**N-1**) rating of 125 MVA.

The maximum demand on TGTS is forecast to remain around 180 MVA over the next ten years. There is a total of 28 MVA of emergency load transfer capacity away from TGTS under maximum demand conditions. The load transfer mitigates only a part of the load-at-risk, hence there is residual load-at-risk at maximum demand under single contingency conditions. Whilst the maximum demand is forecast to continue to breach its (N-1) rating, it is forecast to remain within its (N) rating for the entire period.

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

² [Regulatory investment test for transmission Application guidelines](#), Version 6, Australian Energy Regulator (AER), November 2024.

The minimum demand on TGTS is already very negative, with a reverse power magnitude of 145 MVA. This will increase to around 200 MVA this year and increase by 12 MVA annually every year thereafter for the next ten years. Whilst there are runback schemes on the connected generation in place to protect the transformers at TGTS in the event of reverse-power overload, they are insufficient in their response time when the reverse power exceeds the 187.5 MVA emergency rating under a single contingency condition. To address this limitation, the TGTS transformers are protected with a fast-acting reverse power tripping scheme. It sequentially opens each TGTS sub-transmission circuit breaker under reverse power flow, until the overload is removed. This tripping results in simultaneous disconnection of both generation and customer load. Consequently there is load-at-risk at minimum demand under single contingency conditions. Whilst the minimum demand is forecast to breach its (N-1) emergency rating from 2027, it is forecast to remain within its (N) rating for the entire period.

Due to these forecast capacity limitations at TGTS, the level of EUE is forecast to grow rapidly, deteriorating supply reliability for our customers within the Terang supply area. We have identified that addressing this identified need through reducing the EUE with a prudent level of investment in a network, or non-network solution, will result in a positive net economic benefit. Without intervention, reverse power conditions at TGTS will increasingly trigger protection schemes, resulting in widespread customer outages.

Credible options

The options considered in this PACR to address the identified need include:

- **Option 1** – do nothing (base case)
- **Option 2** – non-network solution
- **Option 3** – install a third transformer (225 MVA) at TGTS and
- **Option 4** – upgrade the 125 MVA transformer to 150 MVA at TGTS.

All the identified network options are credible options. No non-network proposals were received during the *Terang supply area RIT-T project specification consultation report (PSCR)* consultation period. Therefore Option 2 is not considered a credible option for the purposes of this RIT-T in addressing the identified need.

Initial analysis for the PSCR identified Option 3 as the preferred network option at a total cost of \$30 million (real, 2025) by 2028-29. Given this assessment (confirmed by this PACR), we have elected to proceed directly to the PACR stage because:

- the estimated capital cost of that option to address the identified need in this RIT-T is less than the \$54 million threshold³ for mandatory publication of a PADR
- no submissions were received on the PSCR to identify a credible non-network option and
- there is no material change in the identified need, credible options, or input assumptions.

Assessment approach

We have applied the *RIT-T Application Guidelines (Guidelines)* to analyse and rank the economic cost and benefits of each investment options considered in this RIT-T across a range of reasonable scenarios. The robustness of the ranking and optimal timing of options has been investigated through sensitivity analysis involving variations of assumptions around the base case. None of the options considered have a material impact on wholesale market costs. Consequently no market simulation studies have been conducted for this RIT-T.

Options assessment

The preferred option is the one which maximises the present value of the net economic benefit, weighted across a set of reasonable state-of-the-world scenarios. A summary of the 20-year cost-benefit analysis for each credible option and each scenario is provided in Table 1.

³ [AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test](#), Australian Energy Regulator (AER), November 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	Ranking
	25%	50%	25%	100%	
1	0	0	0	0	3
3	4,926	41,805	124,518	53,263	1
4	546	3,446	60,020	16,864	2

Option 3 has the highest present value of net economic benefits for all credible scenarios including the weighted scenario. It is therefore the highest ranked option.

An assessment was undertaken to determine the optimal timing of Option 3. It was identified that whilst the benefits start to exceed the annualised investment cost of the option from 2026-27, the two-year lead time required to deliver this option sets the practical timing to be 2028-29.

A sensitivity study was undertaken to test the robustness of the economic viability and timing of Option 3 to credible changes in key parameters. Under all credible sensitivities, the net present value of benefits remains positive and the timing remains unchanged.

Conclusion

Option 3 is the preferred option as it maximises the present value of net economic benefits under all credible scenarios, including the weighted scenario.

Option 3 (Install a third transformer at TGTS) involves installing a new 220/66 kV 225 MVA transformer (designated B3) and third 66 kV bus, raising the N rating to 500 MVA, the N-1 rating to 275 MVA and the reverse-power emergency rating to 375 MVA. Once in service, it removes the EUE associated with the identified need.

This preferred option is found to have positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver \$53.26 million (real, 2025) in present value net economic benefits over the analysis period. The estimated capital cost of this option is \$30 million (real, 2025) with an identified timing of 2028-29.

This option satisfies the requirements of the RIT-T under clause 5.16.4 of the NER.

Next steps

This PACR concludes the consultation process for the Terang supply area RIT-T.

In accordance with clause 5.16B of the NER, eligible parties may, within 30 days of publication of this PACR, give written notice to the Australian Energy Regulator (**AER**) disputing the conclusions of this PACR in accordance with clause 5.16B of the NER. The dispute notice must set out the grounds for the dispute. A copy of the dispute notice must also be provided to us at the same time with “**Terang Supply Area RIT-T**” titled in the subject header to ritdenquiries@powercor.com.au.

We will proceed to implement the preferred option if there are no dispute notices within 30 days of the publication of this PACR.

Terms and definitions

Table 2: Terms and definitions

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CB	Circuit Breaker
DNSP	Distribution Network Service Provider (distributor)
EUE	Expected Unserved Energy
hr pa	Hours per annum
IASR	Inputs, Assumptions and Scenarios Report
kV	Kilo-Volts
MD / mD	Maximum Demand / Minimum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System Normal Condition
N-1	Single Contingency Condition
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
O&M	Operating and Maintenance
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
POE	Probability of Exceedance
PSCR	Project Specification Consultation Report
REFCL	Rapid Earth Fault Current Limiter
RIT-T	Regulatory Investment Test for Transmission
TCPR	Transmission Connection Planning Report
TGTS	Terang Terminal Station
VCR	Value of Customer Reliability

Term	Definition
Annualised cost	The constant annual amount that has the same present value as the capital cost of an option (spread over its economic life) plus the ongoing annual operating and maintenance costs.
Capital cost	The one-off expenditure required to design, procure, construct and commission a network asset or solution.
Credible option	An option that addresses the identified need, is commercially and technically feasible, and can be implemented in sufficient time to meet the identified need.
Contingency condition ('N-1')	An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Distributor (DNSP)	A distribution network service provider.
Energy-at-risk	The energy at risk of not being supplied if a contingency occurs, and/or under system normal operating conditions (if applicable).
Expected unserved energy (EUE)	The probability-weighted average annual energy not supplied, accounting for load-transfer capability, outage rates, repair times and the likelihood of demand conditions. EUE is valued using the locational value of customer reliability (VCR).
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs, or under system normal operating conditions (if applicable).
Load-duration profile	A curve showing the proportion of time that demand (or reverse-power flow) exceeds any given level over a year. It is used to convert load-at-risk and time-at-risk into expected unserved energy (EUE).
Maximum Demand (MD)	The highest amount of (forecast) net electrical power demand (forward power) for a particular season (summer and/or winter) and year.
Minimum Demand (mD)	If positive, the lowest amount of (forecast) net electrical power demand (forward power). If negative, the highest amount of (forecast) net electrical power generation (reverse power). For a particular season (summer and/or winter) and year.
Network	Refers to the system of physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements in response to an identified need on the network.
Network capacity	Refers to the network's capability to transfer electricity to customers.

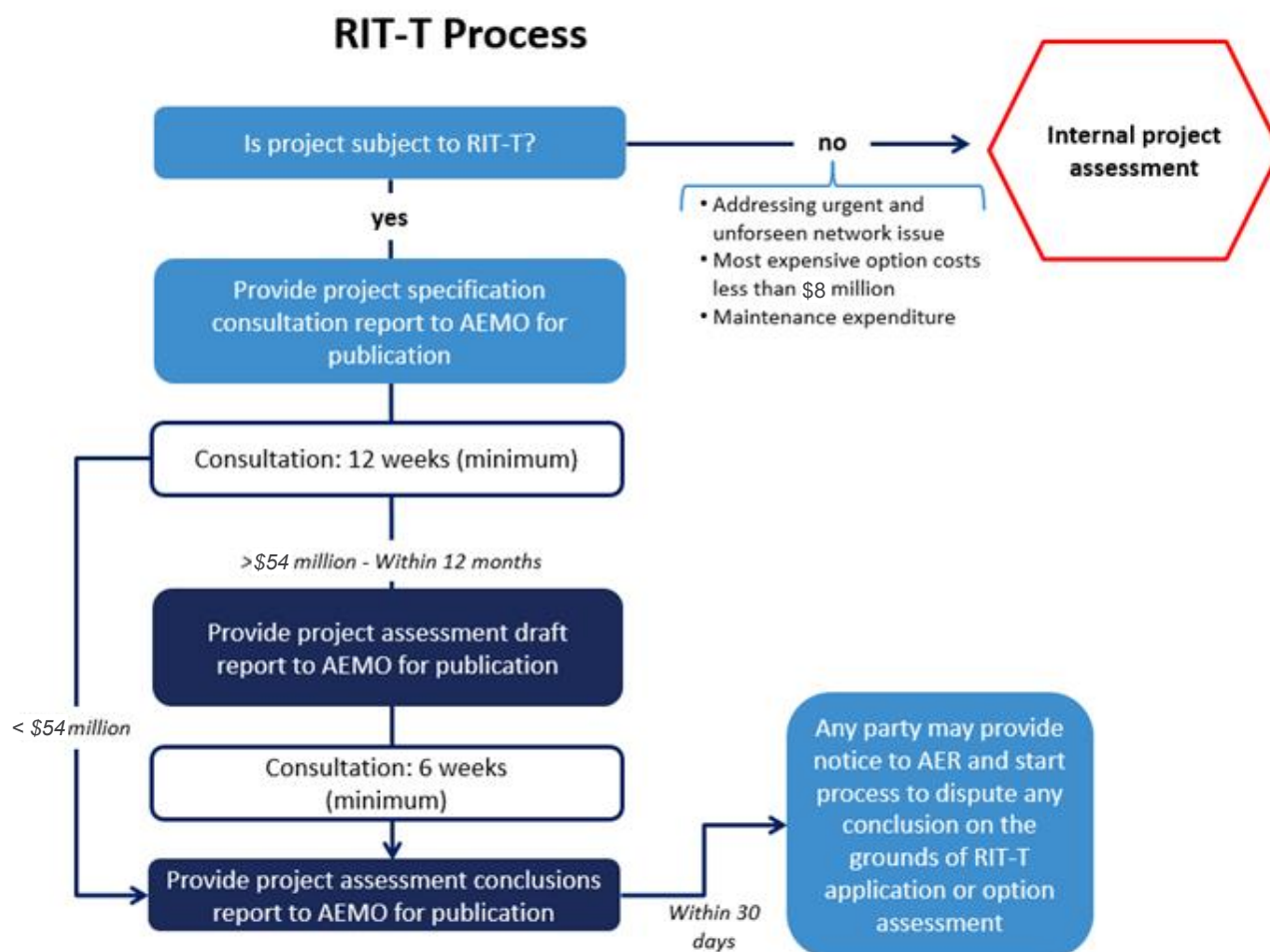
Term	Definition
Non-network option	Any measure to vary peak demand and/or vary local or distributed generation/supply options to support an identified need of the network.
Operating (and Maintenance) cost (O&M)	The ongoing annual cost of operating and maintaining a network after it has been commissioned.
Probability of Exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year. POE50 is the demand expected to be exceeded every second year. POE10 is the demand expected to be exceeded once in ten years.
Regulatory Investment Test for Transmission (RIT-T)	An economic viability test and consultation process that establishes consistent, clear and efficient planning processes for assessing and consulting on transmission network investments over a prescribed limit.
Reverse-power	Power flowing from the distribution system into the transmission system, resulting in negative minimum demand.
Reverse-power emergency rating	The short-term thermal rating of a terminal station under reverse-power (generation export) conditions that is monitored by a fast-acting protection scheme.
Runback scheme	An automatic control scheme that rapidly reduces the output of connected generation when a network limit is approached or exceeded, in order to protect network assets.
Social licence	The ongoing acceptance and approval of a project by local communities and stakeholders. Social-licence costs cover engagement, consultation and related activities required to obtain and maintain that acceptance.
System Normal condition ('N')	The condition where no network assets are under maintenance or forced outage, and the network is operating in a normal configuration.
Terminal Station	A substation facility that houses transmission connection assets, connecting the distribution network to the Victorian transmission system.
Terminal Value	The residual economic value of an asset at the end of the assessment period, reflecting the remaining portion of its technical life. It is included so that long-lived capital costs are not fully written off within the assessment window.
Transmission Connection Asset	Transmission assets within a terminal station that are under the planning responsibility of the distributors (DNSPs) connected to those assets.
Value of Customer Reliability (VCR)	Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).

1. Introduction

We are a regulated Victorian electricity distribution network service provider serving 64 per cent of Victoria spanning from the western suburbs of Melbourne through central and western regional Victoria to the South Australian and New South Wales borders. We serve 945,000 customer connections. The network consists of more than 602,760 poles and over 77,438 kilometres of overhead lines and underground cables. Electricity is received via 138 sub-transmission lines at 155 zone substations, where it is transformed from sub-transmission voltages down to distribution voltages.

The RIT-T is an economic cost-benefit test and consultation process used to assess and rank potential investments capable of meeting an identified need, in accordance with the requirements of clauses 5.15A and 5.16 of the NER⁴. 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 is summarised in Figure 1.

Figure 1: RIT-T process



⁴ [National Electricity Rules](#), Version 253, Australian Energy Market Commission (AEMC), 2026.

The RIT-T applies 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 greater than \$8 million⁵.

We are undertaking this RIT-T to evaluate options to maintain reliability of supply in the Terang supply area (the identified need). Options investigated aim to mitigate the risk of growing EUE, resulting in a forecast deterioration of power supply reliability, from the transmission connection assets at TGTS. The capital cost of credible options to address this identified need are above the RIT-T cost threshold, triggering the requirement for a RIT-T.

PSCR for the first stage of the Terang supply area RIT-T consultation was published in June 2026. During the period of consultation, no non-network proposals or submissions were received from interested stakeholders. Consequently, Option 2 from the PSCR (i.e., non-network solutions) is no longer considered a credible option for the purposes of this RIT-T in addressing the identified need.

Given that

- the estimated capital cost of that option to address the identified need in this RIT-T is less than the \$54 million threshold⁶ for mandatory publication of a PADR
- no submissions were received on the PSCR to identify a credible non-network option and
- there is no material change in the identified need, credible options, or input assumptions,

we have elected not to publish a PADR and instead proceed to publish this PACR.

The PACR is the final stage of the Terang supply area RIT-T consultation process, in accordance with section 4.4 of the Guidelines.

The structure of this PACR is as follows:

- **Chapter 2** describes the identified need seeking to be addressed
- **Chapter 3** identifies credible options that aim to address the identified need
- **Chapter 4** provides a summary and commentary on the consultations to date
- **Chapter 5** presents the scope, costs and residual risks of the credible options
- **Chapter 6** details the assessment approach and assumptions employed for this RIT-T assessment, as well as the materiality of specific categories of market benefits
- **Chapter 7** presents the results of the cost-benefit analysis for each option and identifies the preferred option and its optimal timing, along with scenario and sensitivity analysis results to confirm the robustness of the preferred option to credible changes in assumptions and
- **Chapter 8** presents the conclusions of this PACR, details of the preferred option, and next steps.

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

⁶ [AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test](#), Australian Energy Regulator (AER), November 2024.

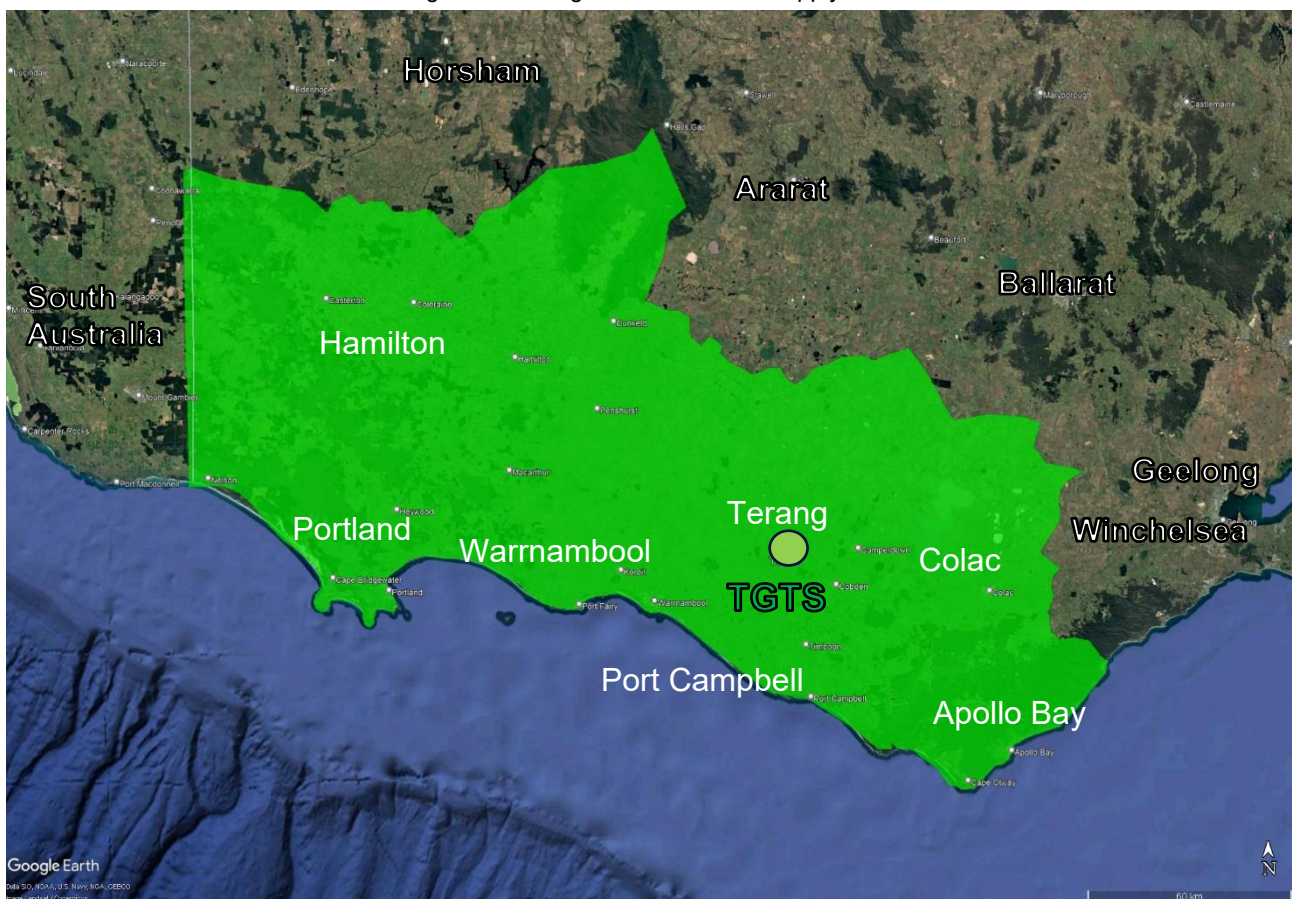
2. Description of the identified need

This chapter discusses the role of TGTS in providing electricity network services to the Terang supply area, and the identified need associated with its current and forecast capacity limitations. Quantification of the risk and costs associated with the forecast increase in EUE in the base case (i.e., the status-quo where no investment is undertaken) is also presented.

2.1 Supply area

The network limitations relevant to the identified need of this RIT-T relates to forecast capacity limitations at TGTS. TGTS is a 220/66 kV terminal station owned and operated by AusNet Transmission Group. It is physically located in Terang. It serves as the main transmission connection point for distribution of electricity to customers within the Terang supply area. Figure 2 illustrates the supply area (highlighted in green) and surrounding areas, relative to the location of TGTS.

Figure 2: Terang Terminal Station supply area

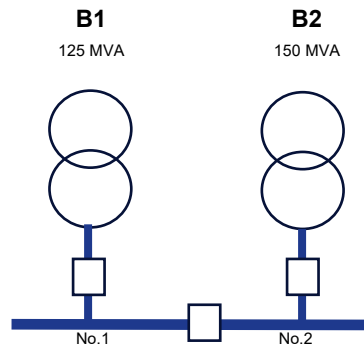


The geographic coverage of the area supplied by TGTS spans south-western Victoria from the South Australian border through Hamilton as far east as Colac and Winchelsea, including towns along the Great Ocean Road and the major coastal city of Warrnambool.

TGTS supplies electricity to more than 64,681 customers. It is also a major collector of power from grid-connected renewable generation, particularly wind farms. A total of 489 MW of embedded generation capacity is installed or committed to be installed on the sub-transmission and distribution systems connected to TGTS. It consists of 346 MW of installed and 72 MW of committed large-scale embedded wind generation, and 71 MW of installed small-scale residential and commercial rooftop solar panels.

TGTS has a single 125 MVA transformer and one 150 MVA transformer, with a system normal (N) rating of 275 MVA and a single contingency (N-1) rating of 125 MVA. This is illustrated in Figure 3.

Figure 3: TGTS transmission connection assets simplified single line diagram



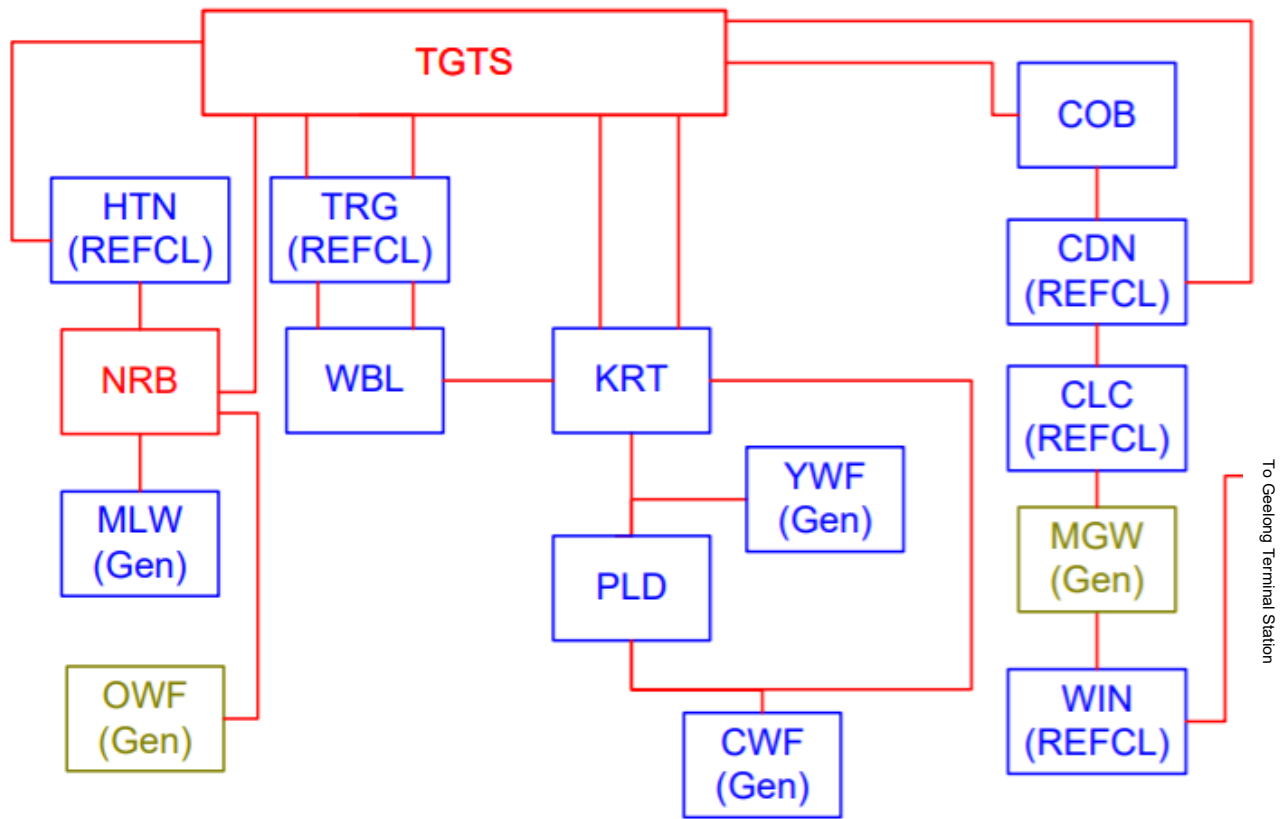
The maximum demand on TGTS is forecast to remain around 180 MVA over the next ten years. There is a total of 28 MVA of emergency load transfer capacity away from TGTS under maximum demand conditions. The load transfer mitigates only a part of the load-at-risk, hence there is residual load-at-risk at maximum demand under single contingency conditions. Whilst the maximum demand is forecast to continue to breach its (N-1) rating, it is forecast to remain within its (N) rating for the entire period.

The minimum demand on TGTS is already very negative, with a reverse power magnitude of 145 MVA. This is expected to increase to around 200 MVA this year and 12 MVA annually thereafter for the next ten years. Whilst there are runback schemes on the connected generation in place to protect the transformers at TGTS in the event of reverse-power overload, they are insufficient in their response time when the reverse power exceeds the 187.5 MVA emergency rating under a single contingency condition. To address this limitation TGTS transformers are protected with a fast-acting reverse power tripping scheme. It sequentially opens each TGTS sub-transmission circuit breaker under reverse power flow, until the overload is removed. This tripping results in simultaneous disconnection of both generation and customer load. Hence there is load-at-risk at minimum demand under single contingency conditions. Whilst the minimum demand is forecast to breach its (N-1) emergency rating from 2027, it is forecast to remain within its (N) rating for the entire period.

Section 6.2.2 provides an overview of the maximum and minimum demand forecasts used in this RIT-T.

The 66 kV sub-transmission networks connected to TGTS is at risk of tripping from the fast-acting reverse power protection scheme, as illustrated in Figure 4, which shows their connecting zone substations and wind farms.

Figure 4: TGTS 66 kV sub-transmission networks simplified single line diagram



2.2 Identified need

From 2027, we expect a capacity shortfall at TGTS to accommodate the forecast maximum and forecast minimum demands with the existing transmission connection assets under single contingency conditions. This is the case under both the 10 per cent (**POE10**) and 50 per cent (**POE50**) probability of exceedance demand forecasts.

The amount of customer energy at risk of involuntary load shedding is will increase as the exposure time for arming the reverse power protection scheme increases due to falling minimum demand. This is likely to lead to a significant deterioration in supply reliability for customers within the Terang supply area.

The identified need for this RIT-T is to maintain electricity supply reliability and mitigate growth in EUE for customers serviced by TGTS.

We have identified that addressing the identified need by reducing the EUE with a prudent level of investment in a network or non-network solution, will result in a positive net economic benefit. Without intervention, reverse power conditions at TGTS will increasingly trigger protection schemes, resulting in widespread customer outages.

2.2.1 Maximum demand risks

Table 3 summarises the forecast maximum demand capacity limitations at TGTS after emergency load transfers. The network asset ratings and forecast demands used to derive these limitations are provided in sections 6.2.1 and 6.2.2 respectively.

Table 3: Forecast maximum demand capacity limitations at TGTS (after emergency transfers)

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Customer load-at-risk - maximum demand above 'N-1' rating (MVA)										
Summer POE10	31	27	23	22	20	19	19	19	19	18
Summer POE50	8	8	6	4	2	1	2	3	3	2
Winter POE10	36	34	34	34	34	35	37	38	39	38
Winter POE50	26	25	25	25	25	26	29	30	30	30
Time-at-risk - maximum demand above 'N-1' rating (hr pa)										
Summer POE10	41	28	18	13	11	10	10	11	10	9
Summer POE50	2	2	1	1	0	0	0	1	1	0
Winter POE10	654	563	565	566	560	620	715	776	782	763
Winter POE50	345	293	299	298	300	350	422	467	471	470

2.2.2 Minimum demand risks

Table 4 summarises the forecast minimum demand capacity limitations at TGTS. The network asset ratings and forecast demands used to derive these limitations are provided in sections 6.2.1 and 6.2.2 respectively.

Table 4: Forecast minimum demand capacity limitations at TGTS

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reverse power overload - minimum demand below 'N-1' emergency rating (MVA)										
Summer POE10	0	15	26	32	39	46	52	56	63	69
Summer POE50	0	0	13	18	24	31	36	42	48	55
Winter POE10	0	21	24	27	30	34	37	41	45	51
Winter POE50	0	7	9	12	16	19	23	26	30	34
Customer load-at-risk - minimum demand below 'N-1' emergency rating (MVA)										
Summer POE10	0	97	95	94	93	92	93	93	93	92
Summer POE50	0	0	89	88	87	87	87	87	87	87
Winter POE10	0	118	118	118	118	119	120	121	121	121
Winter POE50	0	113	113	113	113	114	115	116	116	116

Time-at-risk - minimum demand below 'N-1' emergency rating (hr pa)										
Summer POE10	0	115	167	204	246	285	317	347	384	425
Summer POE50	0	0	240	268	301	341	368	396	424	464
Winter POE10	0	601	637	672	715	753	795	834	885	945
Winter POE50	0	431	446	470	502	530	555	580	607	638

2.2.3 Total value of risk

Annual EUE is calculated by combining the forecast load-at-risk and time-at-risk profiles (from Table 3 and Table 4) with the relevant load-duration profiles, asset outage rates and outage durations, while accounting for available load transfer capability and the probability weighting of the demand scenarios.

The value of EUE is derived by multiplying the level of EUE by an estimate of the locational value of customer reliability (**VCR**). We have adopted the AER's updated estimate of VCR⁷ discussed further in section 6.3.1. The EUE components and the total value of the maximum and minimum demand capacity limitation risk is presented in Table 5, representing the do nothing risk without addressing the identified need.

Table 5: Forecast capacity limitations at TGTS (after emergency transfers)

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Maximum demand EUE (MWh)	29.9	25.1	26.2	27.1	28.0	34.4	45.5	54.7	57.4	58.3
Minimum demand EUE (MWh)	0.0	51.8	73.3	79.2	85.5	85.9	107.1	107.8	107.9	113.4
Total EUE ⁸ (MWh)	29.9	76.9	99.4	106.3	113.5	120.3	152.6	162.5	165.3	171.7
Value of EUE (\$k) ⁹	1,147	2,951	3,819	4,081	4,357	4,620	5,860	6,241	6,349	6,594

The EUE is estimated to have a value to consumers of around \$4.1 million (real, 2025) by 2029, rising to \$6.6 million by 2035. The maximum and minimum demand components of the EUE are shown in Figure 5 and Figure 6 respectively.

⁷ [Values of Customer Reliability](#), Australian Energy Regulator (AER), December 2025.

⁸ The total EUE is the summation of the EUE contribution for both minimum and maximum demand limitations, considering the demand profile and seasonal ratings throughout the year.

⁹ Real 2025. A 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE, also considering the risk reduction provided by the available load transfer capabilities and the likelihood of the operating conditions. This weighting is consistently used by the Victorian DNSPs in its TCPR

Figure 5: TGTS weighted maximum demand EUE component (with emergency transfers applied)

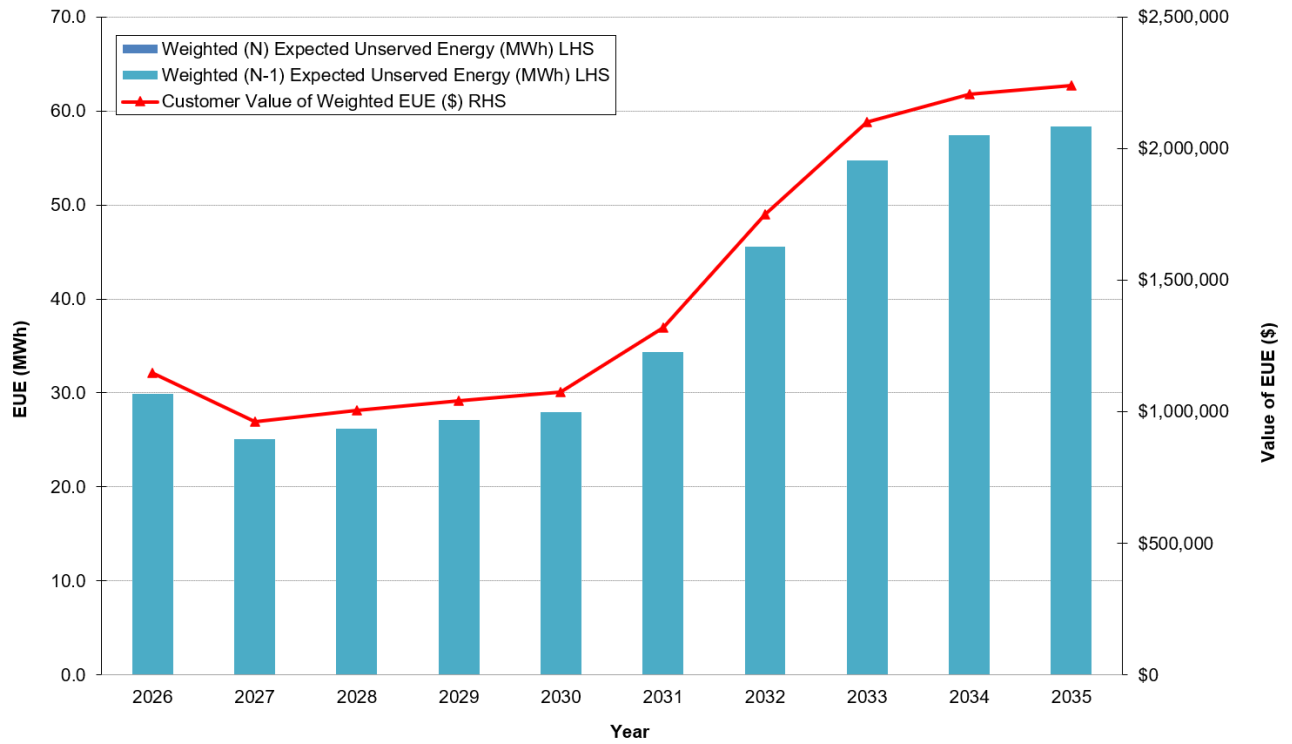
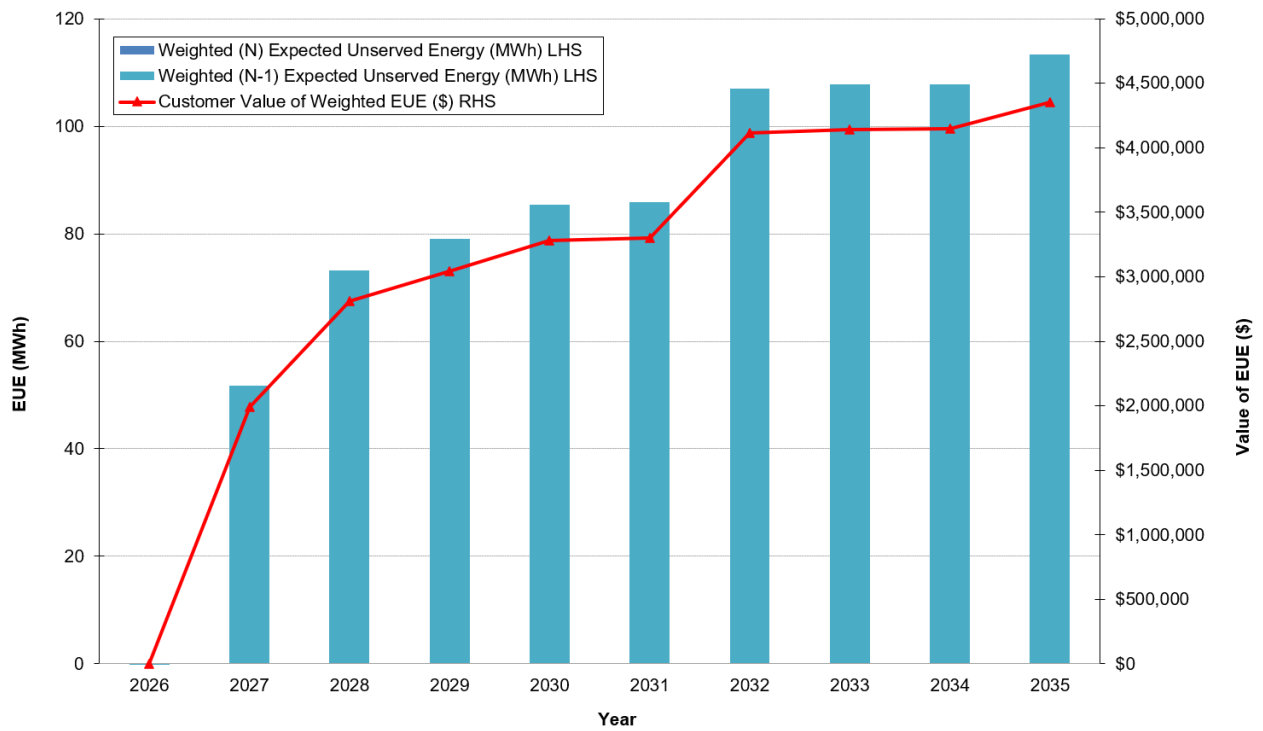


Figure 6: TGTS weighted minimum demand EUE component



3. Credible options assessed

This chapter identifies and describes the credible options aimed at addressing the identified need.

The credible options considered include:

- **Option 1** – do nothing (base case) continues to supply customers serviced by TGTS 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 2** – non-network solutions is a contract for network support services within the sub-transmission and distribution networks serviced by TGTS, to vary the net demand on TGTS to address the identified need. Network support services could include services such as voluntary load dispatch (e.g. demand response), aggregated distributed energy resources (e.g. virtual power plants), or larger-scale dispatchable embedded storage and/or generation resources
- **Option 3** – install a third 220/66 kV transformer (225 MVA) with a third 66 kV bus at TGTS to increase the thermal capacity of the TGTS transmission connection assets to address the identified need. There is provision to accommodate this transformer at TGTS and
- **Option 4** – upgrade the 220/66 kV 125 MVA transformer to 150 MVA at TGTS to increase the thermal capacity of the TGTS transmission connection assets to partially address the identified need. There is provision to accommodate this transformer at TGTS.

The assessment uses Option 1 as the base case against which other options are assessed.

Options 2, 3 and 4 could address the identified need, at least in part. The different options will all result in lower EUE than in the base case. The extent of the reduction varies across the options due to the differences in the additional thermal capacity ratings they provide.

Following the PSCR consultation not identifying a credible non-network solution, Option 2 is not progressed as a credible option. Option 3 and 4 now remain the only options assessed in this PACR.

4. Submissions to the consultations

This chapter provides a summary of, and commentary on, the submissions to consultations to date for the Terang supply area RIT-T.

In June 2026 we published the PSCR for the Terang supply area RIT-T, being the first stage consultation of this RIT-T process. This consultation provided an opportunity for non-network providers and other stakeholders to submit proposals for alternative solutions to address the identified need.

During this period of consultation no non-network proposals or submissions were received from interested stakeholders. Consequently Option 2 from the PSCR is no longer considered a credible option for the purposes of this RIT-T.

Given that

- the estimated capital cost of that option to address the identified need in this RIT-T is less than the \$54 million threshold¹⁰ for mandatory publication of a PADR
- no submissions were received on the PSCR to identify a credible non-network option and
- there is no material change in the identified need, credible options, or input assumptions,

we have elected not to publish a PADR for consultation and instead proceed directly to the PACR stage.

¹⁰ [AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test](#), Australian Energy Regulator (AER), November 2024.

5. Credible options costs and benefits

This chapter presents the scope, costs, residual risks and benefits of the base case and credible options assessed in this PACR.

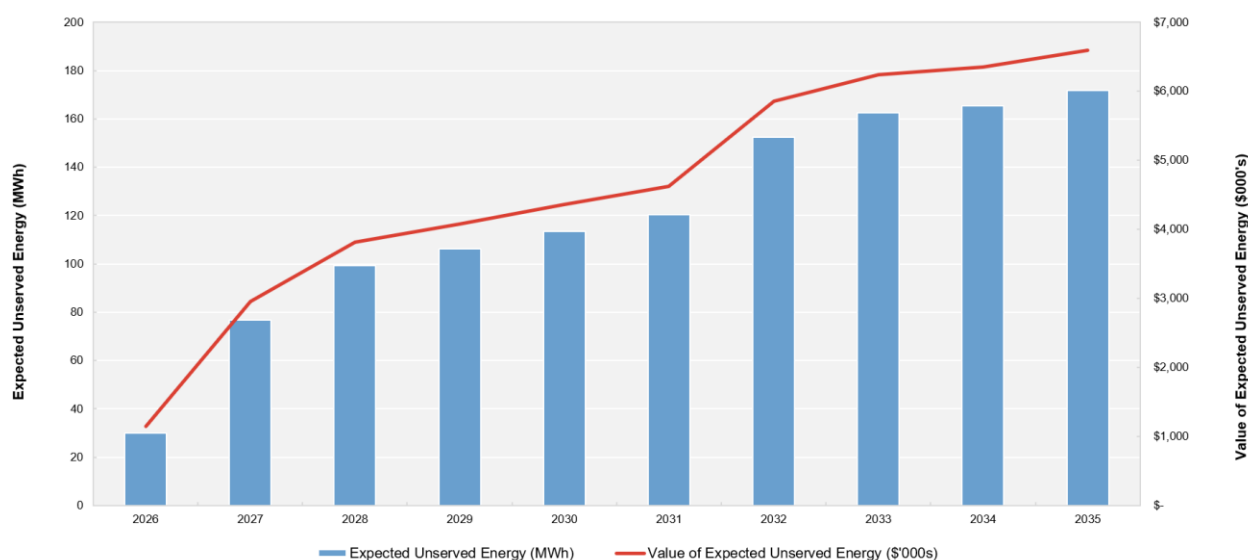
5.1 Option 1 – Do nothing (base case)

The do nothing option continues to supply customers serviced by TGTS without any intervention to manage increasing EUE levels (i.e., status quo).

This option leads to significant supply interruptions and unserved energy under single contingency (N-1) conditions at times of maximum and minimum demand, because of capacity shortfalls at TGTS.

As detailed in Table 5 for the supply reliability risk associated with the TGTS capacity limitations, the value of the EUE risk for the do nothing option (using the components shown in Figure 5 and Figure 6), is forecast to increase from \$1.1 million in 2026 to \$6.6 million by 2035 (real, 2025), as illustrated in Figure 7.

Figure 7: Do nothing total risk costs (Option 1)



In the context of this RIT-T, the do nothing option is the base case against which all other credible options will be considered, to identify the option that maximises the present value of net economic benefit. Since no incremental expenditure is undertaken under the do nothing option, it is considered a zero-cost and zero-benefit option.

5.2 Option 2 – Non-network solution

Credible non-network solutions may be contracted to provide network support services from within the distribution or sub-transmission networks serviced by TGTS to address the identified need (at least in part). Network support services could include services such as voluntary load dispatch (demand response), aggregated distributed energy resources (virtual power plants), or larger-scale dispatchable (or standby) embedded storage and/or generation resources.

In June 2026 we published a PSCR for the Terang supply area RIT-T. This consultation provided an opportunity for non-network providers and other stakeholders 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.

Consequently, 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.

5.3 Option 3 – Install a third transformer (225 MVA) at TGTS

This option involves installing a new 220/66 kV 225 MVA transformer (designated B3) as shown in Figure 8 to increase the capacity on TGTS to accommodate higher maximum demand and greater reverse power flows, thereby addressing the identified need in full.

Figure 8: TGTS transmission connection assets simplified single line diagram after Option 3

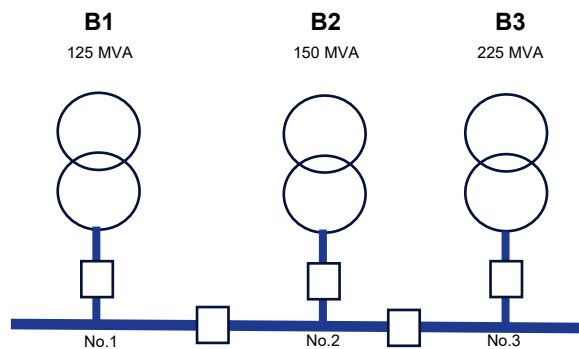


Table 6 provides a summary of the expected capability of TGTS for (N) and (N-1) conditions, following the completion of Option 3.

Table 6: TGTS capacity ratings (MVA) after Option 3

Condition	Option 3 rating (MVA)
System normal (N)	500
Single contingency (N-1)	275
Reverse power emergency (N-1)	375

The forecast demand at TGTS is expected to remain the same following completion of Option 3.

This option has a total estimated capital cost of \$30 million (real, 2025), which has a present value capital cost of \$25.8 million, and has an annualised cost of \$2.3 million (includes \$0.15 million of operating and maintenance costs).

Figure 9 compares the annualised cost of Option 3 with the annual value of avoided EUE risk. The crossover point (where avoided risk exceeds annualised cost) occurs in 2026-27. Allowing for a two-year design, procurement and construction program, the earliest practicable commissioning date is summer 2028-29.

This option once in service, meets the identified need by alleviating the supply capacity risk and removing all the EUE over the next ten years.

Figure 9: Optimal timing based on avoided risks and annualised costs (Option 3)

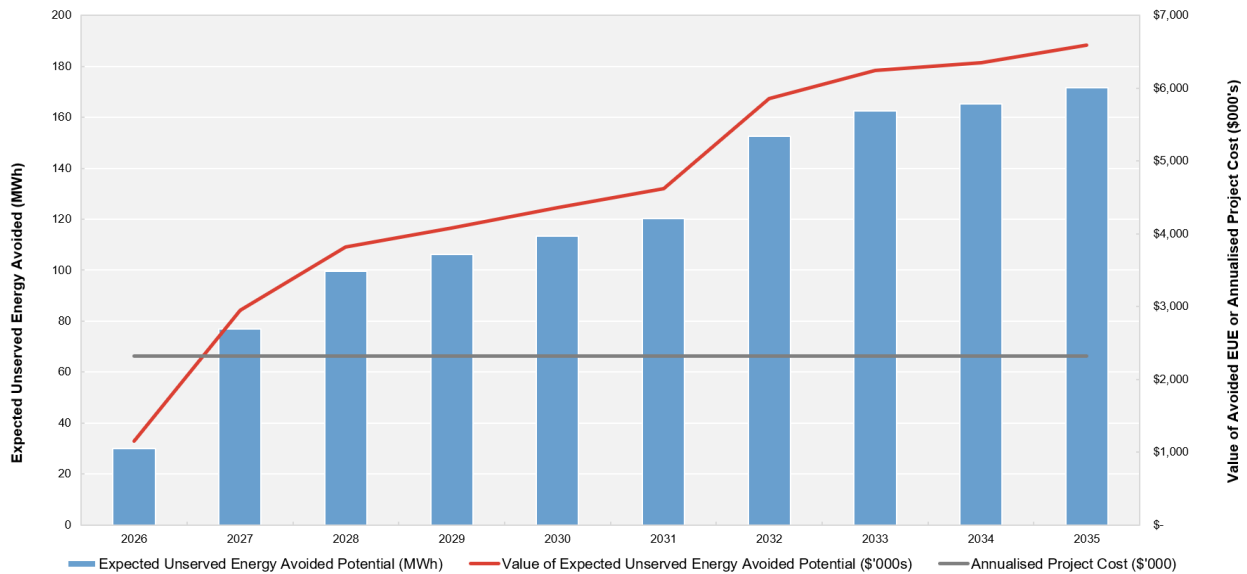


Table 7 lists the forecast residual EUE and its value at TGTS with Option 3 in service in 2028-29.

Table 7: Forecast residual risk at TGTS (Option 3)

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Maximum demand EUE (MWh)	29.9	25.1	26.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Minimum demand EUE (MWh)	0.0	51.8	73.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total EUE¹¹ (MWh)	29.9	76.9	99.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Value of EUE (\$k)¹²	1,147	2,951	3,819	0	0	0	0	0	0	0

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

Social licencing risks are considered minor as Option 3 only involves works contained within an existing substation. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

¹¹ The total EUE is the summation of the EUE contribution for both minimum and maximum demand limitations, considering the demand profile and seasonal ratings throughout the year.

¹² Real 2025. A 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE, also considering the risk reduction provided by the available load transfer capabilities and the likelihood of the operating conditions. This weighting is consistently used by the Victorian DNSPs in its TCPR

5.4 Option 4 – Upgrade the 125 MVA transformer to 150 MVA at TGTS

This option involves replacing the 125 MVA transformer with a new 220/66 kV 150 MVA transformer at TGTS to marginally increase the capacity on TGTS to accommodate somewhat higher maximum demand and greater reverse power flows as shown in Figure 10, thereby addressing the identified need in part.

Figure 10: TGTS transmission connection assets simplified single line diagram after Option 4

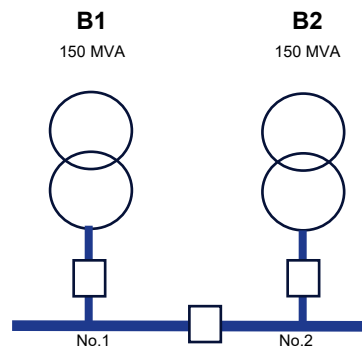


Table 8 provides a summary of the expected capability of TGTS for (N) and (N-1) conditions, following the completion of Option 4.

Table 8: TGTS capacity ratings (MVA) after Option 4

Condition	Option 4 rating (MVA)
System normal (N)	300
Single contingency (N-1)	150
Reverse power emergency (N-1)	200

The forecast demand at TGTS is expected to remain the same following completion of Option 4.

This option has a total estimated capital cost of \$30 million (real, 2025)¹³, which has a present value capital cost of \$25.8 million, and has an annualised cost of \$2.3 million (includes \$0.15 million of operating and maintenance costs).

Figure 11 compares the annualised cost of Option 4 with the annual value of avoided EUE risk. The crossover point (where avoided risk exceeds annualised cost) occurs in 2026-27. Allowing for a two-year design, procurement and construction programme, the earliest practicable commissioning date is summer 2028-29.

This option once in service, only meets the identified need in part by alleviating some of the supply capacity risk, removing some of the EUE over the next ten years.

¹³ Although the scope of Options 3 and 4 differs materially, the current preliminary cost estimates for both options are approximately \$30 million. This reflects the different equipment, installation, outage, civil, protection and associated works required for each option.

Figure 11: Optimal timing based on avoided risks and annualised costs (Option 4)

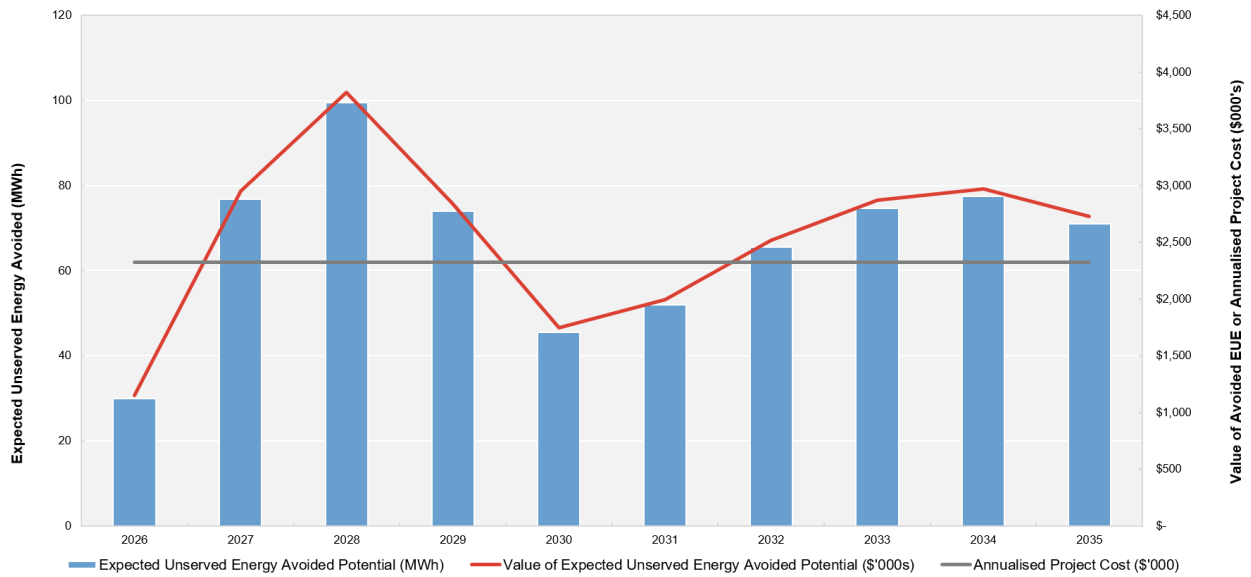


Table 9 lists the forecast residual EUE and its value at TGTS with Option 4 in service in 2028-29.

Table 9: Forecast residual risk at TGTS (Option 4)

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Maximum demand EUE (MWh)	29.9	25.1	26.2	0.1	0.1	0.1	0.3	0.4	0.5	0.4
Minimum demand EUE (MWh)	0.0	51.8	73.3	32.2	68.0	68.3	86.8	87.4	87.5	100.3
Total EUE ¹⁴ (MWh)	29.9	76.9	99.4	32.3	68.0	68.4	87.0	87.8	88.0	100.7
Value of EUE (\$k) ¹⁵	1,147	2,951	3,819	1,242	2,613	2,628	3,343	3,373	3,378	3,869

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

Social licencing risks are considered minor for this option as works are contained within the existing substation. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

¹⁴ The total EUE is the summation of the EUE contribution for both minimum and maximum demand limitations, considering the demand profile and seasonal ratings throughout the year.

¹⁵ Real 2025. A 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE, also considering the risk reduction provided by the available load transfer capabilities and the likelihood of the operating conditions. This weighting is consistently used by the Victorian DNSPs in its TCPR

6. Assessment approach

This chapter discusses the assessment methodology for the cost-benefit assessment of options under this RIT-T, which forms the key focus of this PACR in confirming the preferred option. This includes the:

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

6.1 Assessment method

Consistent with the RIT-T requirements¹⁶, cost benefit analysis guidelines¹⁷ and RIT-T application guidelines¹⁸, we have undertaken a cost-benefit analysis to evaluate and rank the net economic benefits of credible options. All options considered are assessed against a do nothing option.

In planning the network, we use 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 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:

- 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, we consider the potential cost of each credible option, and the reduction in reliability risk that each option provides, to identify whether the investment will result in a positive net economic benefit. This leads into the analysis that we have undertaken as part of the RIT-T process, 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,

¹⁶ [Regulatory investment test for transmission](#) Australian Energy Regulator (AER), Version 3, 21 November 2024.

¹⁷ [Cost Benefit Analysis guideline](#) Australian Energy Regulator (AER), Version 3, 21 November 2024.

¹⁸ [RIT-T application guidelines](#) Australian Energy Regulator (AER), Version 6, 21 November 2024.

conditions exist where some of the load cannot be supplied under rare (but credible) conditions, such as at times of maximum demand, or with a single network element out of service.

6.2 Input assumptions

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

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

6.2.1 Network asset ratings

The capability of the transmission connection assets at TGTS is limited by the thermal rating of its two 220/66 kV transformers. Table 10 provides a summary of the capability of TGTS for (N) and (N-1) conditions.

Table 10: TGTS capacity ratings (MVA)

Condition	Existing rating (MVA)
System normal (N)	275
Single contingency (N-1)	125
Reverse power emergency (N-1)	187.5

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

6.2.2 Forecast maximum demand

The forecast maximum demand at TGTS is specified according to POE10 and POE50 weather conditions¹⁹ during the summer and winter seasons. Table 11 and Table 12 provide summaries of the forecast maximum and minimum²⁰ demand for TGTS respectively. Values in red indicate that the (N-1) rating is exceeded, noting that in no years is the (N) rating exceeded.

¹⁹ Victorian electricity demand is sensitive to ambient temperature. Maximum demand forecasts are therefore based on demand during extreme temperature conditions that could occur once every ten years (POE10) and those that could occur every second year (POE50).

²⁰ The reverse power as measured by the reverse power protection scheme.

Table 11: TGTS forecast maximum demand (MVA)

TGTS	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer POE10	184	180	176	175	173	172	172	172	172	171
Summer POE50	161	161	159	157	155	154	155	156	156	155
Winter POE10	189	187	187	187	187	188	190	191	192	191
Winter POE50	179	178	178	178	178	179	182	183	183	183

Table 12: TGTS forecast reverse power demand (MVA)

TGTS	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer POE10	147	202	214	220	227	234	239	244	250	257
Summer POE50	130	183	200	206	212	219	224	229	235	242
Winter POE10	144	209	212	214	218	221	225	228	233	238
Winter POE50	127	194	196	199	203	207	210	214	217	222

Note, the reverse power values presented in this table are negative minimum demands.

Table 13 presents the assumed underlying demand load factor that is used in calculating the annual amount of underlying customer energy that is shed by the operation of the reverse power protection scheme.

Table 13: Load factor of average underlying demand (proportion of maximum demand)

TGTS	Load factor
Summer POE10	0.54
Summer POE50	0.56
Winter POE10	0.63
Winter POE50	0.64

6.2.3 Load transfer capability

There is 28 MVA of capacity to transfer load away from TGTS to other adjacent terminal stations through our network. There is no capacity to transfer generation away from TGTS.

6.2.4 Annual load profile

In calculating annual load profiles, we use historical demand and generation profiles to estimate the load profiles of the forecast underlying load and generation contributions as the basis on which to calculate EUE for this report.

The load-duration curves for TGTS are shown in Figure 12 and Figure 13 for maximum demand and reverse power peak periods respectively, for winter and summer seasons.

Figure 12: Load-duration profile for TGTS for maximum demand

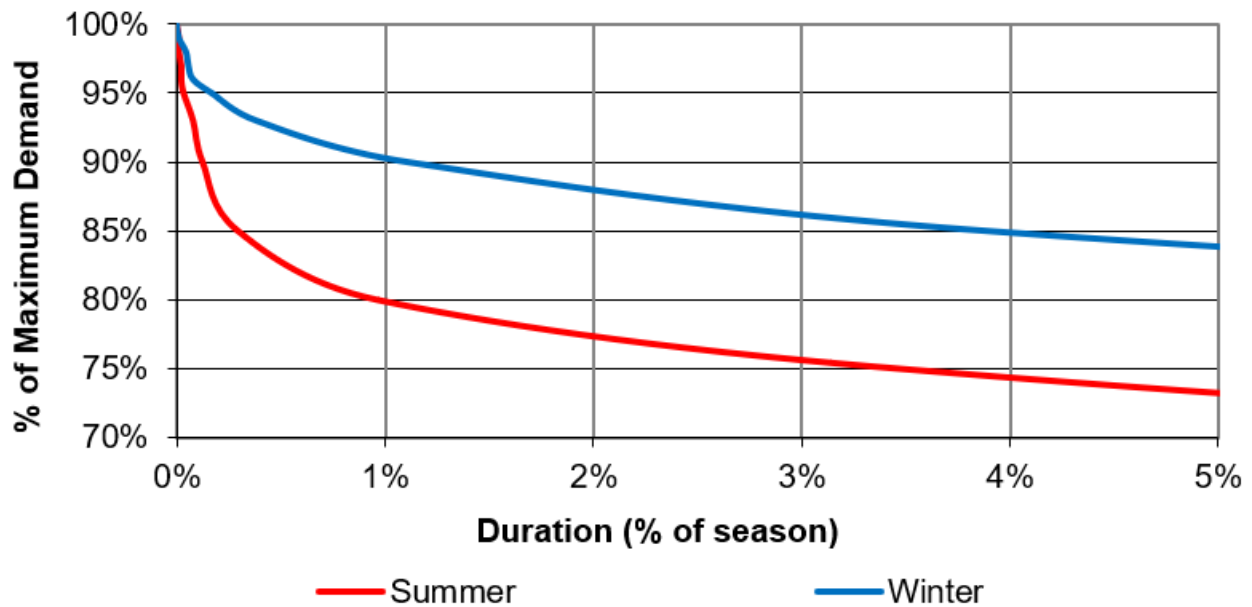
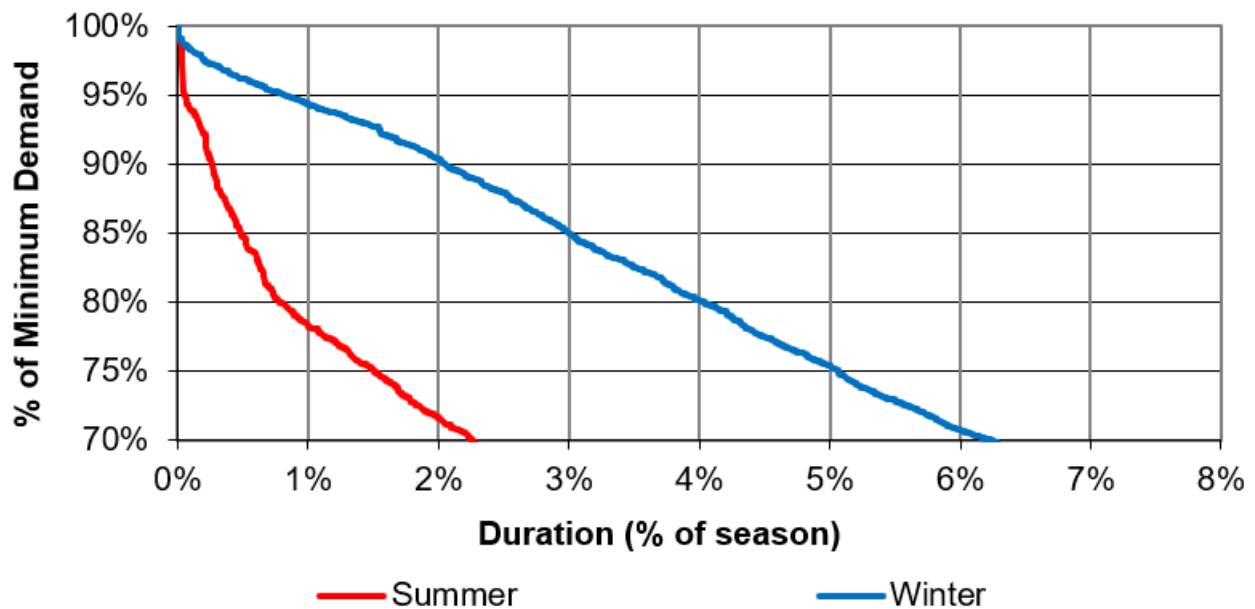


Figure 13: Load-duration profile for TGTS for reverse power



6.2.5 Network asset reliability

Table 14 provides a summary of the TGTS transformer reliability information used in the EUE analysis. The major failure rate condition (which has a long duration repair) dominates the maximum demand contribution to EUE, whereas the minor failure rate condition (which has a much higher frequency of occurrence) dominates the reverse power protection scheme's contribution to EUE.

Table 14: TGTS transformer reliability information²¹

Power Transformer Reliability Quantity	Value	Description
Major forced outage rate (failure rate)	1.0% per annum	A major outage is expected to occur once per 100 transformer-years. In a population of 100 terminal station transformers, expect one major failure of any one transformer per year.
Weighted average of major outage duration (repair time)	2.6 months	On average, 2.6 months is required to repair the transformer, during which time the transformer is not available for service.
Expected transformer unavailability due to a major outage per transformer-year	0.221%	On average, each transformer would be expected to be unavailable due to major outages for $0.01 \times 2.6/12 = 0.221\%$ of the time, or 19 hours per year.
Minor forced outage rate (failure rate)	1 per annum	A minor forced outage is expected to occur once per year.
Weighted average of minor outage duration (inspection time)	4 hours	On average, 4 hours is required to inspect the transformer, during which time the transformer is not available for service.
Expected transformer unavailability due to a minor outage per transformer-year	0.046%	On average, each transformer would be expected to be unavailable due to minor outages for $1 \times 4/8766 = 0.046\%$ of the time, or 4 hours per year.

6.3 Key assessment parameters

The key assessment parameters used in this RIT-T apply to the:

- value of customer reliability
- discount rate and
- assessment period.

6.3.1 Value of customer reliability

The cost of EUE is calculated using the VCR, which is an estimate of the value consumers place on having a reliable electricity supply. We have applied locational VCR values based on the estimates made by the AER in its revised *Values of Customer Reliability Review* published in December 2025²². Specifically, applying the AER's VCR estimates for different sectors (i.e., residential, commercial, industrial and agricultural) to terminal station level recent energy composition data, we have calculated the VCR for TGTS of \$38,403/MWh.

²¹ [Transmission Connection Planning Report](#) (TCPR), Section 4.7, Victorian DNSPs, December 2025.

²² [Values of Customer Reliability](#), Australian Energy Regulator (AER), December 2025.

6.3.2 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 TGTS, aligned with AEMO's *2025 inputs, assumptions and scenarios report (IASR)*²³.

For the sensitivity analysis we use 10.0 per cent for the high bound, and 4.69 per cent for the low bound (representing a regulatory discount rate).

6.3.3 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 cost-benefit analysis has been taken over a 20-year period, from 2026 to 2045, 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 to the end of the evaluation period.

We consider that the length of this assessment period considers the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. The assessment period accounts for the expected demand growth in the supply area intended to be addressed by the credible options in this RIT-T.

6.4 Approach to cost estimation for network options

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

The costs presented 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.

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.

Social licence costs have been included but are not expected to be material given the proposed works are contained within the existing terminal station site. The importance of allocating appropriate costs to social licence activities is supported by our established best practice in regulated electricity infrastructure delivery, as articulated in our *Commitment on Engagement and Land Access (document)*²⁴. The document recognises that effective, genuine stakeholder engagement is fundamental to gaining and maintaining a social licence to operate. This is particularly the case where projects impact landowners and local communities. Social licence is not incidental to project delivery; it is built through early, sustained engagement, collaboration, and the resolution of community concerns, with the objective of minimising negative impacts and maximising shared benefits. Our approach demonstrates that social licence activities require structured processes, dedicated engagement teams, negotiated land access arrangements, complaints handling mechanisms, and compliance with formal regulatory instruments. These measures are consistent with contemporary expectations of trust, credibility and legitimacy placed on regulated network service providers.

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

²³ [2025 Inputs, Assumptions and Scenarios Report](#), Table 31, Australian Energy Market Operator (AEMO), August 2025.

²⁴ [Powercor commitment on engagement and land access](#), Powercor Australia.

6.5 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 that²⁵:

- 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.

6.5.1 Material classes of market benefits

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 credible options considered in this RIT-T assessment.

6.5.2 Material benefits not considered material

We expect that the following classes of market benefits are unlikely to be material to the RIT-T assessment for any of the credible 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 voluntary load dispatch**, as no credible non-network option capable of providing the required service was identified, and therefore there is no material difference in voluntary load dispatch between the credible options assessed.
- **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.
- **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.
- **Changes in network losses**, as changes in network losses are 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.
- **Changes in ancillary services costs**, as the options are not expected to impact on the demand for and supply of ancillary services.
- **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 SF₆ emissions from high-voltage switchgear, are negligible and unlikely to be a material class of market benefits for any of the credible options.
- **Competition benefits**, as there is no competing generation affected by the limitations and risks being addressed by the options considered for this RIT-T.
- **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).
- **Any avoided penalty for not meeting any relevant government-imposed instruments**, as there have not been any penalties identified that would warrant consideration of these in this RIT-T.
- **Avoided unrelated network expenditure**, as we do not expect the options to affect other proposed network expenditure.

²⁵ [Regulatory Investment Test for Transmission](#), Version 3, paragraphs 7 and 11, Australian Energy Regulator (AER), November 2024.

- **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.

6.6 Sensitivity studies

The robustness of the investment decision is tested using the input assumptions described in Table 15. This analysis varies the assumptions used for the base case as detailed in sections 6.2 and 6.3.

Table 15: Input assumptions used for the sensitivity studies

Parameter	Lower bound	Base 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
Forecast maximum demand	95% of base case maximum demand	100% of base case maximum demand	105% of base case maximum demand
Forecast minimum demand	95% of base case minimum demand	100% of base case minimum demand	105% of base case minimum demand
Asset failure rate	80% of base	100% of base	120% of base
Value of customer reliability	80% of AER VCRs locational for TGTS	100% of AER VCRs locational for TGTS	120% of AER VCRs locational for TGTS
Discount rate	4.69% - regulatory discount rate	7.00% - commercial discount rate (IASR)	10.00% (IASR)
Asset life	20 years	45 years	60 years

6.7 Scenario modelling to address uncertainty

The RIT-T analysis is required to incorporate several 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 PACR was conducted under three future-state scenarios by choosing the parameters in Table 15 with high uncertainty, as follows:

- Central scenario – the base case assumptions in Table 15
- Low scenario – lower bound maximum and minimum demand, failure rates and VCR and
- High scenario – higher bound maximum and minimum 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 16, 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.

Table 16: Parameters with high uncertainty used for scenario modelling

Parameter	Low scenario	Central scenario	High scenario	Reasoning
	25%	50%	25%	
Forecast maximum demand	Lower bound	Base case	Higher bound	Over the last two decades 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.
Forecast minimum demand	Lower bound	Base case	Higher bound	Uncertainty exists in the number, size and timing of grid-scale generators forecast at this point of connection to the transmission network.
Asset failure rate	Lower bound	Base case	Higher bound	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.
Value of customer reliability	Lower Bound	Base Case	Higher Bound	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.

6.8 RIT-T reopening triggers

As the estimated capital costs of the credible options are below the \$103 million threshold²⁶, the RIT reopening trigger requirements in NER clause 5.16.4(k)(10) do not apply. Nevertheless, we propose the following project-specific triggers as prudent monitoring measures:

- an increase in the cost of the preferred option by more than 30 per cent or
- changes in the forecast maximum demand that would cause the preferred option identified by the RIT-T to be no longer the preferred option or
- a non-preferred network credible option present value real cost decrease of 25 per cent or more or
- the preferred option is unable to be delivered for any reason, to address the identified need.

²⁶ [AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test](#), Australian Energy Regulator (AER), November 2024.

7. Options assessment

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

7.1 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 benefits of each option is presented in Table 17 based on their identified timing.

Table 17: Calculated present value of gross benefits relative to base case (\$'000, real 2025)

Option	Low scenario	Central scenario	High scenario
1	0	0	0
3	30,731	67,610	150,323
4	26,351	29,251	85,825

7.2 Capital and operating costs

The estimated present value of capital, operations and maintenance costs of each option relative to the do nothing base case is presented in Table 18 based on their identified timing

Table 18: Calculated present value of capital and operating costs relative to base case (\$'000, real 2025)

Option	Low scenario	Central scenario	High scenario
1	0	0	0
3	25,805	25,805	25,805
4	25,805	25,805	25,805

7.3 Present value of net economic benefits

The calculated 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 19 based on their identified timing.

Table 19: Calculated present value of net economic benefits relative to base case (\$'000, real 2025)

Option	Low scenario	Central scenario	High scenario	Weighted scenario	Ranking
	25 per cent	50 per cent	25 per cent	100 per cent	
1	0	0	0	0	3
3	4,926	41,805	124,518	53,263	1
4	546	3,446	60,020	16,864	2

7.4 Preferred option

The cost-benefit assessment has identified that the preferred option to address the identified need is Option 3, being the installation of a third transformer (225 MVA) at TGTS, because it maximises the present value of net economic benefits under all credible scenarios including the weighted scenario. This option satisfies the requirements of the RIT-T.

7.5 Sensitivity of the preferred option

This section tests the robustness of the economic viability and identified timing of Option 3 as the preferred option for different assumptions of key parameters as detailed in Table 15.

The robustness of the preferred option's net economic benefits to credible variations in key parameters (in Table 15), is demonstrated in the sensitivity study results of Figure 14. Under all credible sensitivities, the net present value of benefits remains positive for Option 3.

Figure 14: Present value of net benefits sensitivity analysis of the preferred option (\$'000, real 2025)

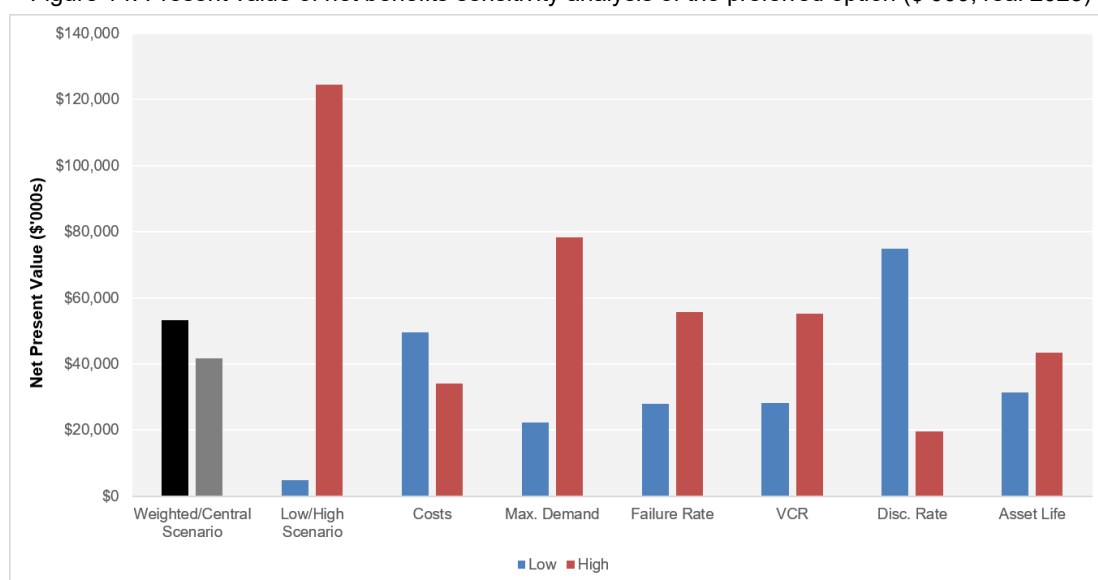


Table 20 presents the changes in timing away from the identified timing of 2028-29 for each sensitivity.

Table 20: Sensitivity of the optimal timing with respect to variation of key parameters

Parameter	Lower Bound	Higher Bound
Capital and operating costs	No change	No change
Forecast maximum demand	No change	No change
Forecast minimum demand	No change	No change
Asset failure rate	No change	No change
Value of customer reliability	No change	No change
Discount rate	No change	No change
Asset life	No change	No change

The identified timing remains 2028-29 under all sensitivity cases examined because the growth in reverse-power causes the optimal timing to fall before the practical timing, even under lower-bound assumptions.

8. Conclusion and next steps

This chapter presents the conclusions of the PACR, details of the preferred option, and next steps.

8.1 Conclusion

Based on the cost-benefit analysis presented in Chapter 7, Option 3 is the preferred option because it maximises the present value of net economic benefits under all credible scenarios, including the weighted scenario.

Option 3 (Install a third transformer at TGTS) involves installing a new 220/66 kV 225 MVA transformer (designated B3) and third 66 kV bus, raising the N rating to 500 MVA, the N-1 rating to 275 MVA and the reverse-power emergency rating to 375 MVA. Once in service it fully removes the EUE associated with the identified need.

This preferred option is found to have positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver \$53.26 million (real, 2025) in present value net economic benefits over the analysis period. The estimated capital cost of this option is \$30 million (real, 2025) with an identified timing of 2028-29.

This option satisfies the requirements of the RIT-T under clause 5.16.4 of the NER.

8.2 Next steps

This PACR concludes the consultation process for the Terang supply area RIT-T.

In accordance with clause 5.16B of the NER, eligible parties may, within 30 days of publication of this PACR, give written notice to AER disputing a conclusion made in this PACR in accordance with clause 5.16B of the NER. The dispute notice must set out the grounds for the dispute. A copy of the dispute notice must be sent to us at the same time with **“Terang Supply Area RIT-T”** as the subject header to ritdenquiries@powercor.com.au.

We will proceed to implement the preferred option if there are no dispute notices within 30 days of the publication of this PACR.

9. Appendix A – RIT-T compliance checklist

This appendix sets out a checklist in Table 21 which demonstrates the compliance of this PACR with the requirements of clauses 5.16.4(k) and (v) of the NER, version 253.

Table 21: PACR 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 5
(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Chapter 6
(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Chapter 6
(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);	Chapter 6
(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Chapter 7
(8) the identification of the preferred option;	Chapter 7
(9) for the 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 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 preferred option satisfies the regulatory investment test for transmission;	Chapter 5, 7, & 8
(10) if each of the following apply to the RIT-T project: (i) the estimated capital cost of the 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;	Chapter 6 (not applicable – capital cost well below threshold; project-specific triggers provided as good practice)
(v)(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under the project assessment draft report (if published).	Chapter 4 (no PADR published; no submissions received on the PSCR)

