RIT-T: Terang Supply Area – Project Specification Consultation Report

Powercor Australia Ltd

June 2026

Table of Contents

List of figures

List of tables

Executive summary

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

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

The regulatory investment test for transmission (RIT-T) is an economic cost-benefit test and consultation process used to assess and rank potential investments capable of meeting an identified need, in accordance with the requirements of 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 relates to forecast transmission connection asset capacity limitations at Terang Terminal Station (TGTS), a major source of supply to Powercor's electricity distribution network in south-western regional Victoria. The limitations arise predominantly from forecast generation growth within the broader Terang supply area serviced by TGTS, impacting the reliability of supply to Powercor's customers.

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 RIT-T is being undertaken by Powercor (the lead proponent of this RIT-T), in accordance with the requirements of the NER and section 4.2 of the RIT-T Application Guidelines[2].

This project specification consultation report (PSCR) is the first stage of the Terang Supply Area RIT-T consultation process. This report contains information to enable prospective non-network providers to propose alternative options, including demand-side response and storage solutions, to address the identified need.

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 within the Terang supply area.

TGTS is a 220/66 kV terminal station owned and operated by AusNet Transmission Group, and is located in Terang in Victoria's south-west. It serves as the main transmission connection point for distribution of electricity to customers within the Terang 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 and is also 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 on the Powercor 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.

[1] National Electricity Rules, version 247, Australian Energy Market Commission (AEMC), 2026.
[2] Regulatory investment test for transmission Application guidelines, version 6, Australian Energy Regulator (AER), November 2024.

TGTS has one 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.

The maximum demand on TGTS is forecast to remain at around 180 MVA every year for 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 period.

The minimum demand on TGTS is already strongly negative, with a reverse power magnitude of 145 MVA. This is expected to increase to around 200 MVA this year, and increase by 12 MVA 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 under that condition, the TGTS transformers are protected with a fast-acting reverse power tripping scheme. It sequentially opens each TGTS subtransmission 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 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. Powercor has identified that addressing this identified need by reducing the EUE with a prudent level of investment in a network or non-network solution, is expected to result in a positive net economic benefit. Without intervention, reverse power conditions at TGTS will increasingly trigger protection schemes, resulting in widespread customer outages.

Potential credible options

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

- **Option 1** – Do nothing (base case);
- **Option 2** – Non-network solution;
- **Option 3** – Install a third transformer (225 MVA) at TGTS; and
- **Option 4** – Upgrade the 125 MVA transformer to 150 MVA at TGTS.

Initial analysis by Powercor has identified that Option 3 is likely to be the preferred network option at a total cost of $30 million (real, 2025) by 2028-29. This assessment will be confirmed through the RIT-T process.

We have commenced a RIT-T consultation because the estimated capital cost of the most expensive credible option to address the identified need exceeds the trigger of $8 million[3] for undertaking a RIT-T (and the estimated capital cost of all other credible options also exceeds this threshold).

[3] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test, Australian Energy Regulator (AER), 12 November 2024

Request for submissions

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

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

> **Richard Robson**
> Manager Subtransmission Planning and Major Connections, Powercor
> rittenquiries@powercor.com.au

The consultation on this PSCR is open for 12 weeks, consistent with the NER requirements[4].

Submissions are due on or before 11th September 2026.

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

Next steps

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

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

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

Powercor intends to move to the next stage of the RIT-T in the third quarter of 2026.

It should be noted that the estimated capital cost of the most expensive credible option to address the identified need in this RIT-T is less than the $54 million threshold for mandatory publication of a PADR. In accordance with the National Electricity Rules, where the estimated capital cost is below this threshold, Powercor may elect to proceed directly to a Project Assessment Conclusions Report (PACR) only where:

- no submissions identify a credible non-network option, and
- there is no material change in the identified need, credible options, or input assumptions.

Accordingly, subject to these conditions being satisfied, Powercor may elect to proceed directly to a PACR rather than publish a PADR.

[4] NER, clause 5.16.4(g).

Terms and definitions

Table 1: 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
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
NSA	Network Support Agreement
NSP	Network Service Provider
O&M	Operations 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
Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Contingency condition ('N-1')	An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Distributor (DNSP)	A distribution network service provider.
Energy-at-risk	The energy at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Expected unserved energy (EUE)	Refers to an estimate of the probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for a cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Minimum Demand (mD)	The lowest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Network	Refers to the system of physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's capability to transfer electricity to customers.

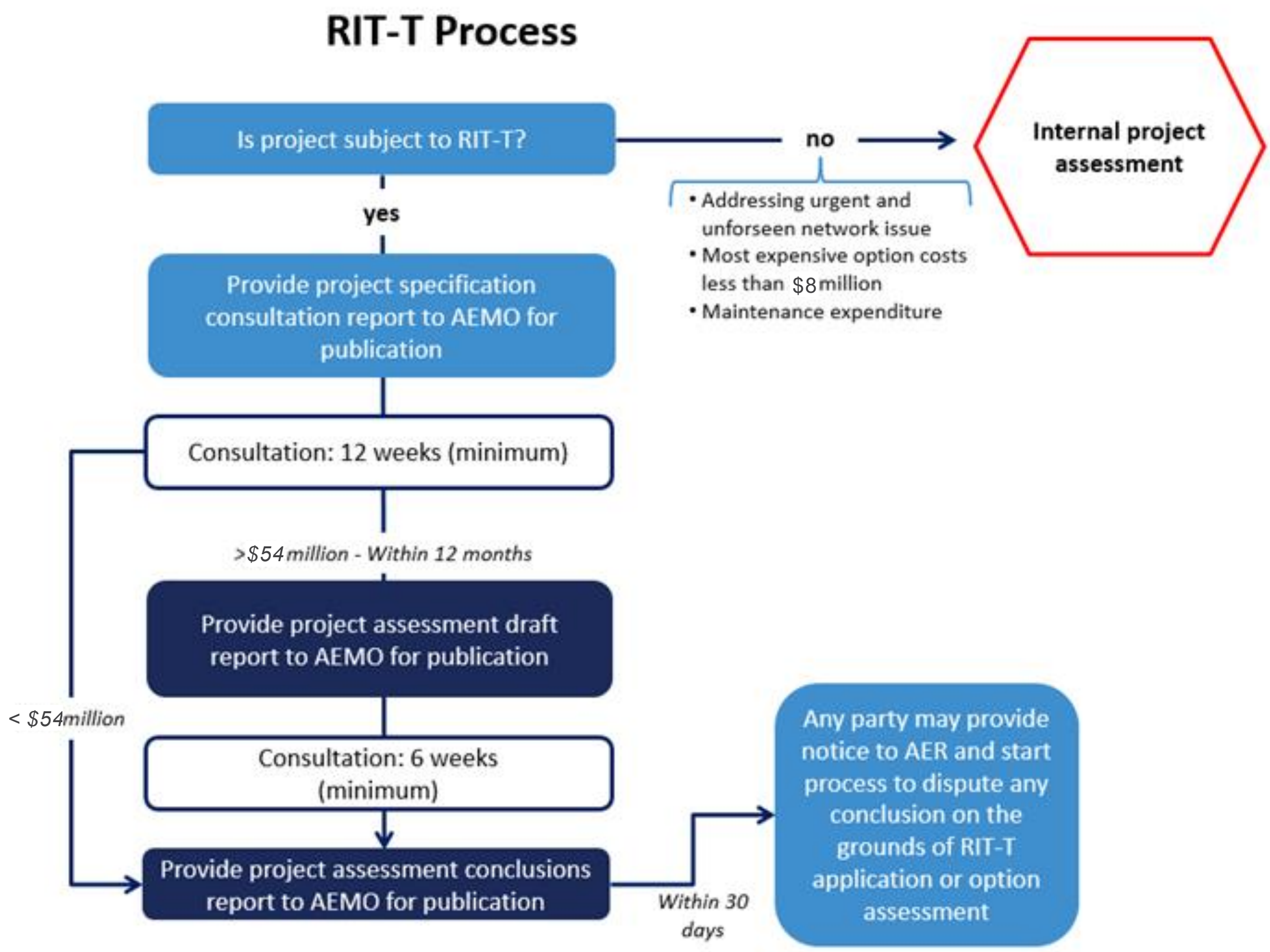
Term	Definition
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.
Probability of Exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Transmission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

1. Introduction

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

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)[5]. 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



[5] National Electricity Rules, version 247, Australian Energy Market Commission (AEMC), 2026.

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[6].

Powercor is undertaking this RIT-T to evaluate options to maintain reliability of supply in the Terang 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 Terang Terminal Station (TGTS). The capital cost of credible options (including the proposed preferred network option) to address this identified need within the supply area is above the RIT-T cost threshold, and so has triggered the requirement for a RIT-T.

This project specification consultation report (PSCR) is the first stage of the Terang Supply Area RIT-T consultation process and has been prepared by Powercor in accordance with the requirements of clause 5.16 of the NER and section 4.2 of the RIT-T Application Guidelines[7]. This report contains information to enable prospective non-network providers to propose alternative options, including demand-side response and storage solutions, to address the identified need.

The structure of this PSCR is as follows:

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

[6] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test, Australian Energy Regulator (AER), 12 November 2024.

[7] Regulatory investment test for transmission application guidelines, version 6, Australian Energy Regulator (AER), November 2024.

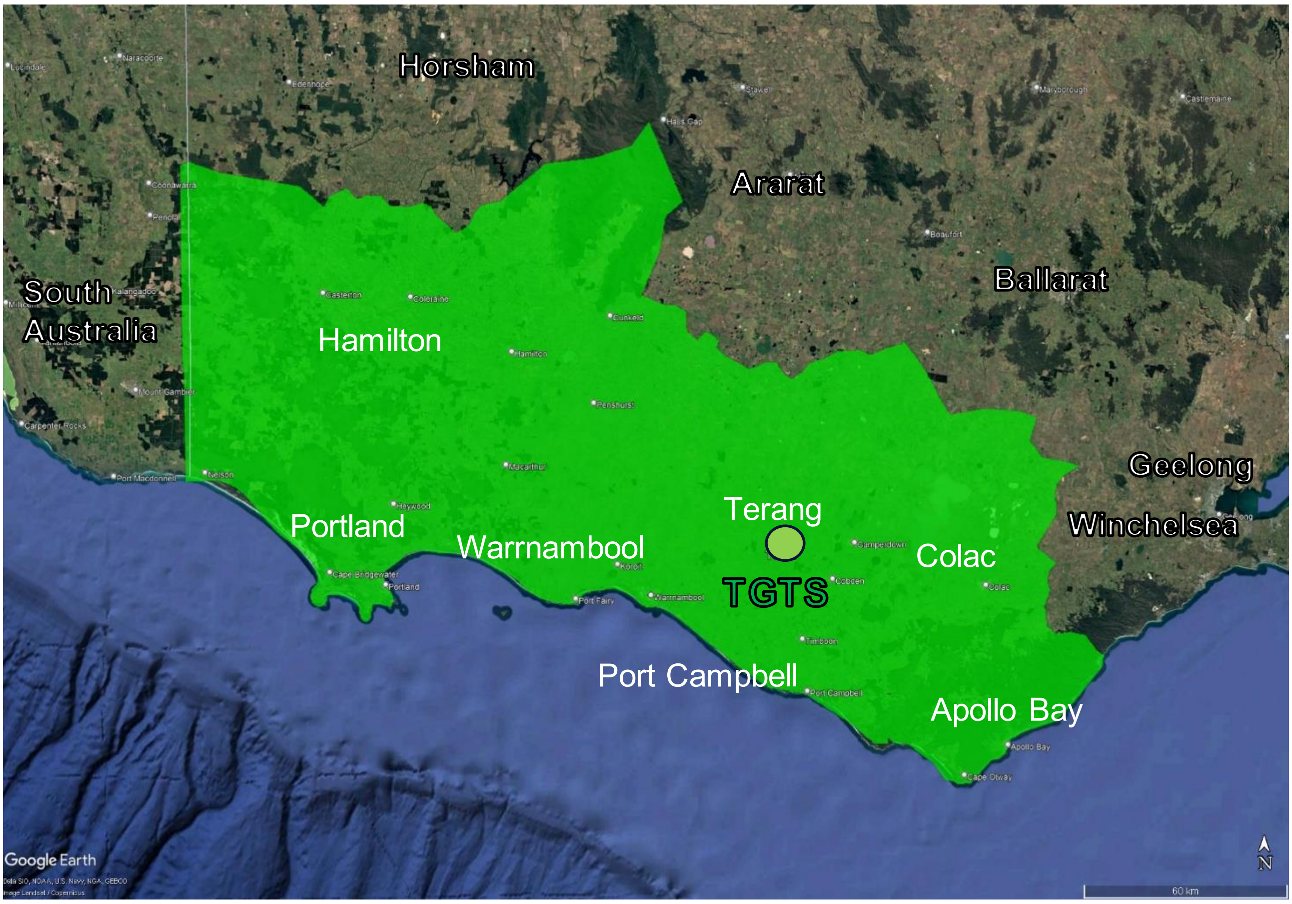
2. Description of the identified need

The NER and the AER's RIT-T Application Guidelines require that a PSCR must include a description of the need. This chapter addresses this requirement[8], presenting the role of Terang Terminal Station (TGTS) in providing electricity network services and the identified need associated with its 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 Supply area

The network limitations relevant to the identified need of this RIT-T relates to forecast capacity constraints at TGTS. TGTS is a 220/66 kV terminal station owned and operated by AusNet Transmission Group, and is located in Terang in Victoria's south-west. 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 (TGTS) supply area



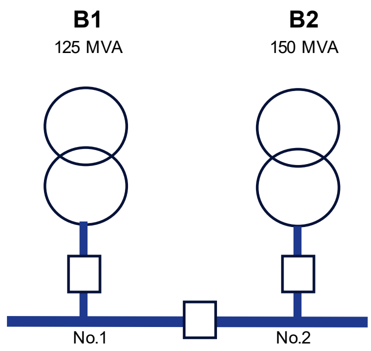
The geographic coverage of the area supplied by TGTS spans south-western Victoria from the South Australian border through Hamilton as far east as Colac and Winchelsea, including towns along the Great Ocean Road and the major coastal city of Warrnambool.

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

TGTS supplies electricity to more than 64,681 customers and is also 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 on the Powercor 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 one 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



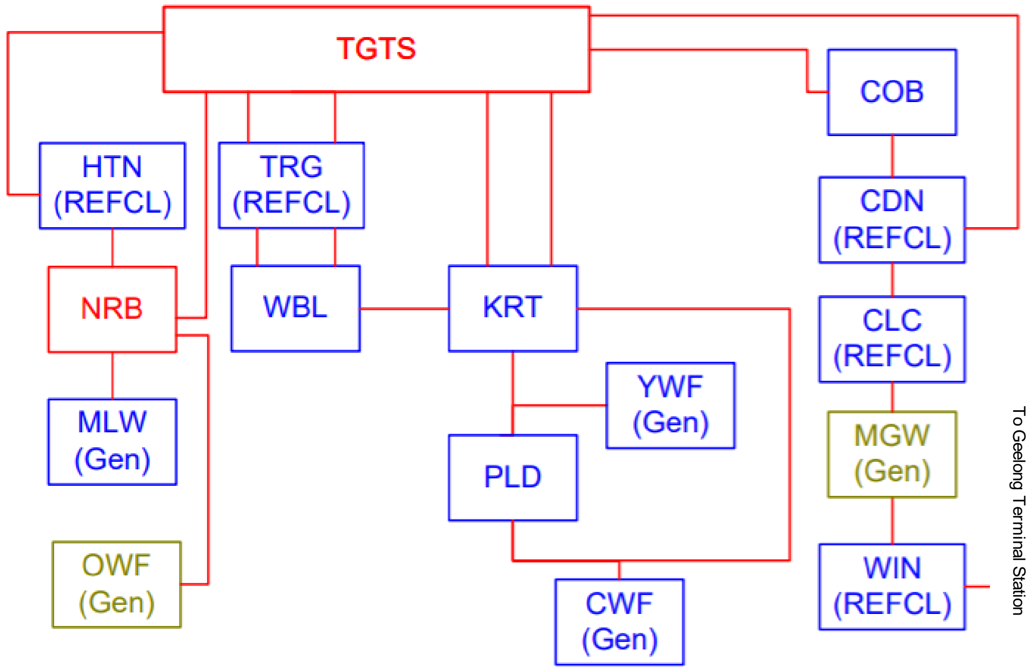
The maximum demand on TGTS is forecast to remain at around 180 MVA every year for the next ten years. There is a total of 28 MVA of emergency load transfer capacity away from TGTS under maximum demand conditions. The load transfer mitigates only a part of the load-at-risk, hence there is residual load-at-risk 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 period.

The minimum demand on TGTS is already strongly negative, with a reverse power magnitude of 145 MVA. This is expected to increase to around 200 MVA this year, and increase by 12 MVA 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 under that condition, the TGTS transformers are protected with a fast-acting reverse power tripping scheme. It sequentially opens each TGTS subtransmission 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 period.

Section 3.2.2 provides an overview of the maximum and minimum demand forecasts used in this RIT-T.

The 66 kV subtransmission networks connected to TGTS at risk of tripping from the fast-acting reverse power protection scheme, are illustrated in Figure 4, showing their connecting zone substations and wind farms (Gen).

Figure 4: TGTS 66 kV subtransmission networks simplified single line diagram



2.2 Identified need

From 2027, Powercor is expecting a capacity shortfall at TGTS to accommodate the forecast maximum and forecast minimum demands with the existing transmission connection assets under single contingency conditions, based on both 10% (POE10) and 50 % (POE50) probability of exceedance demand forecasts.

The amount of customer energy at risk of involuntary load shedding is expected to 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 expected unserved energy (EUE) for customers serviced by TGTS within the Terang supply area.

Powercor has identified that addressing this identified need by reducing the EUE with a prudent level of investment in a network or non-network solution, is expected to 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 2 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 3.2.1 and 3.2.2 respectively.

Table 2: 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 3 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 3.2.1 and 3.2.2 respectively.

Table 3: 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

The EUE (in MWh) is calculated from Table 2 and Table 3 by multiplying the energy at risk with the capacity unavailability giving the expected reliability risk in each year. The value of EUE is derived by multiplying the level of EUE by an estimate of the Value of Customer Reliability (VCR). We have adopted the AER's updated estimate of VCR[9] discussed further in section 6.1.1. The EUE components and the total value of the maximum and minimum demand capacity limitation risk is presented in Table 4.

Table 4: Weighted[10] value of 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[11] (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[12])	**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.

[9] Values of Customer Reliability, Australian Energy Regulator (AER), December 2025.
[10] 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.
[11] The total EUE is the summation of the EUE contribution during 'N-1' single contingency conditions (considering asset unavailability), and the EUE contribution during 'N' system normal conditions, considering the demand profile and seasonal ratings through out the year.
[12] Real 2025.

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

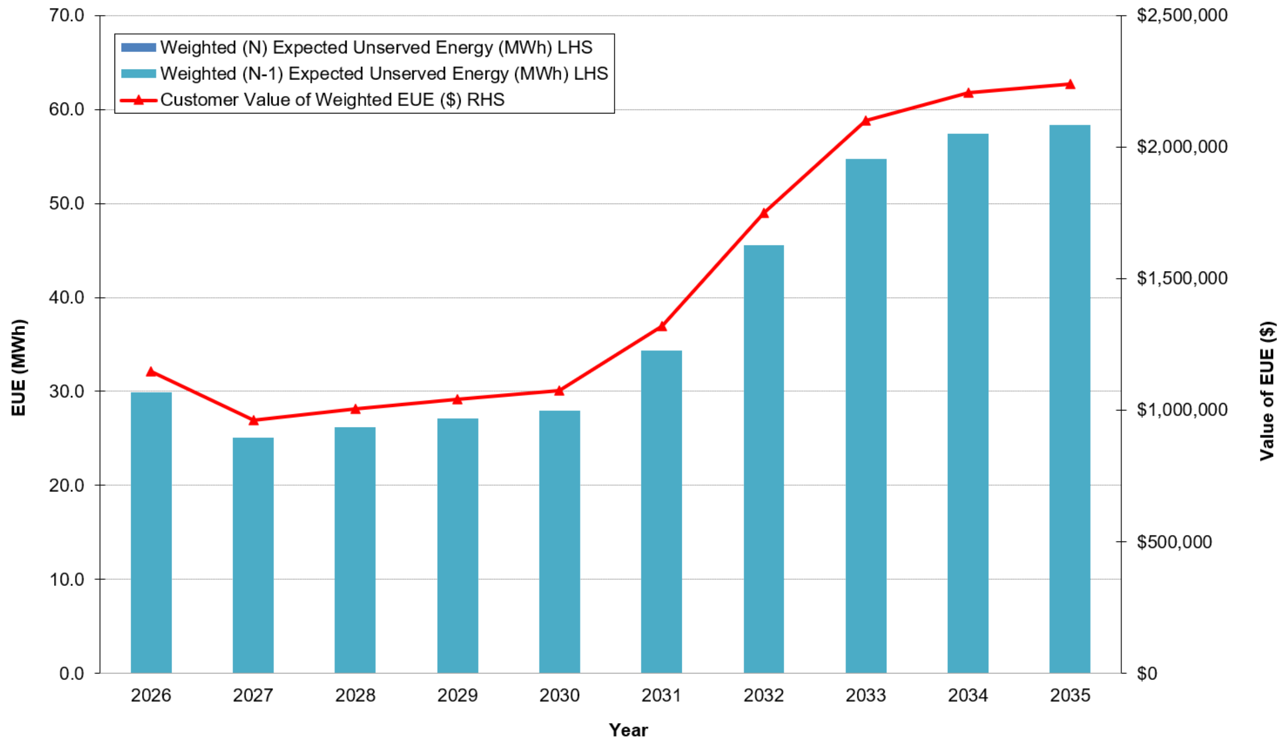
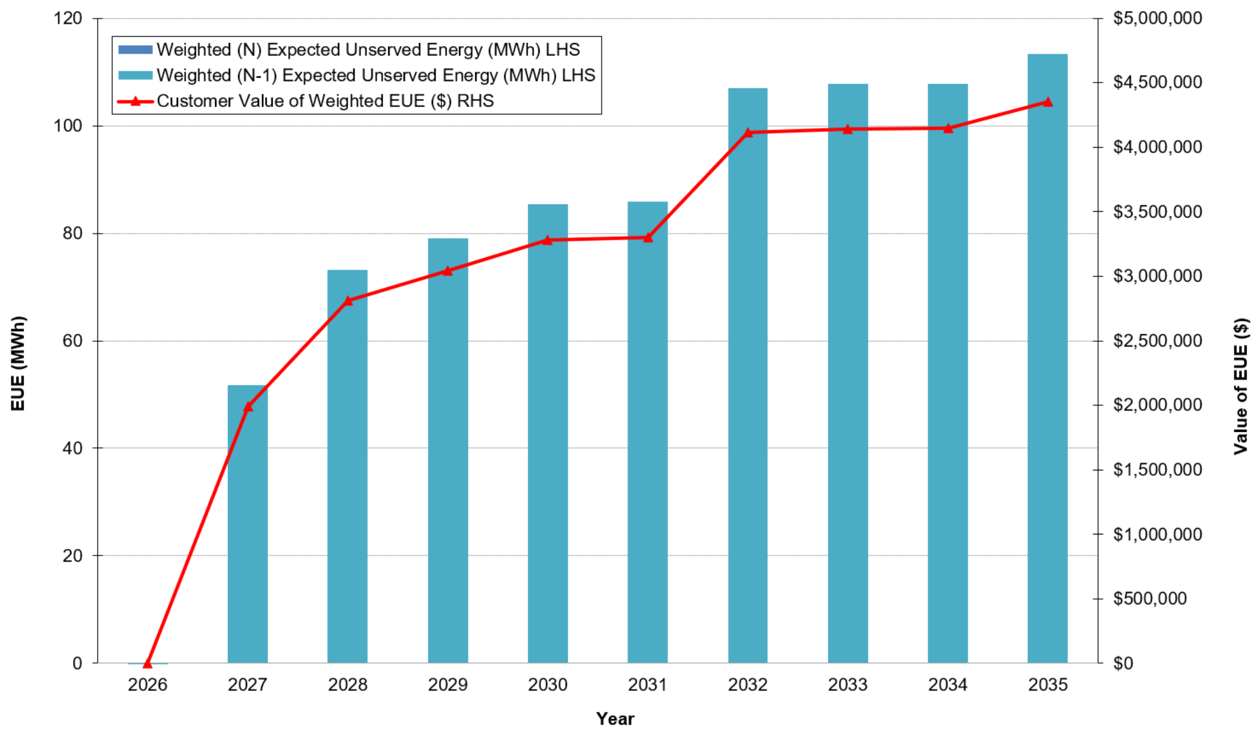


Figure 6: TGTS weighted minimum demand EUE component



3. Assumptions used in identifying the identified need

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

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

3.1 Overview of proposed approach to the NPV analysis

Consistent with the RIT-T requirements[13], cost benefit analysis guidelines[14] and RIT-T application guidelines[15], Powercor will undertake a cost-benefit analysis to evaluate and rank the net economic benefits of credible options. All options considered will be assessed against a status-quo 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 chapter 6.

In planning the network, Powercor applies 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:

- 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, Powercor will then consider the potential costs of credible options, and the reduction in reliability risk that each option provides, to identify whether the investment will result in a positive net market benefit. This leads into the analysis that we will undertake as part of the next stage of the RIT-T process, where the credible option that maximises the present value of net economic benefit is identified by:

- quantifying 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 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.

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[13] Regulatory investment test for transmission Australian Energy Regulator (AER), Version 3, 21 November 2024.
[14] Cost Benefit Analysis guideline Australian Energy Regulator (AER), Version 3, 21 November 2024.
[15] RIT-T application guidelines Australian Energy Regulator (AER), Version 6, 21 November 2024.

3.2 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).

3.2.1 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 5 provides a summary of the capability of TGTS for (N) and (N-1) conditions.

Table 5: TGTS capacity ratings (MVA)

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

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

3.2.2 Forecast maximum demand

The forecast maximum demand at TGTS is specified according to POE10 and POE50 weather conditions[16] during the summer and winter seasons. Table 6 and Table 7 provide summaries of the forecast maximum and minimum[17] demand for TGTS respectively. Values in red indicate that the (N-1) rating is exceeded, noting that in no years is the (N) rating is exceeded.

Table 6: 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

[16] 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).
[17] The reverse power as measured by the protection scheme.

Table 7: 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 8 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 8: 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

3.2.3 Load transfer capability

There is 28 MVA of capacity to transfer load away from TGTS to other adjacent terminal stations through Powercor's network, whereas there is no capacity to transfer generation away from TGTS.

3.2.4 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 7 and Figure 8 for maximum demand and reverse power peak periods respectively, for winter and summer seasons.

Figure 7: Load-duration profile for TGTS for maximum demand

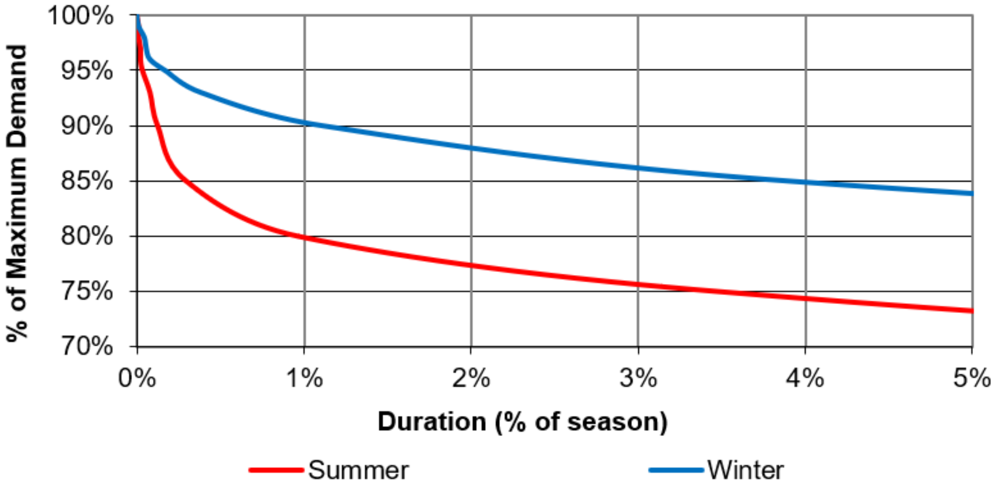
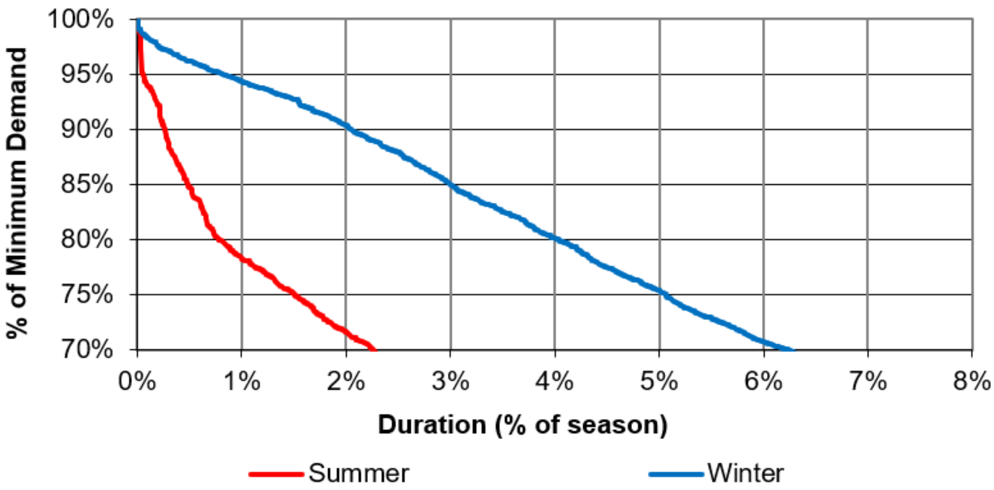


Figure 8: Load-duration profile for TGTS for reverse power



3.2.5 Network asset reliability

Table 9 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 9: TGTS transformer reliability information[18]

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 x 2.6/12 = 0.221% of the time, or 19 hours per year.
Minor forced outage rate (failure rate)	1 per annum	A minor 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 x 4/8766 = 0.046% of the time, or 4 hours per year.

[18] Section 4.7 of the 2025 Transmission Connection Planning Report (TCPR).

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

The NER and the AER's RIT-T Application Guidelines require that a PSCR must include the technical characteristics of the identified need that a non-network option would be required to deliver in the form of network support services, to alleviate the forecast capacity limitations at TGTS[19].

4.1 Performance requirements

Non-network options must be capable of increasing demand or reducing generation (either pre-contingent or instantaneous post-contingent), to keep TGTS reverse power flows less than the reverse power protection scheme setting of 187.5 MVA. Any proposed solution must be technically feasible and failsafe.

Initial analysis by Powercor has identified that Option 3 is likely to be the preferred network option with an annualised cost of $2.3 million (real, 2025) which represents the maximum available annual payment that could be available to non-network providers (in aggregate) for a network support option.

The latest date that a network support service needs to be in place to defer the preferred network option is start of financial year 2028-29.

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

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

Powercor considers that the TGTS reverse power limitation is the driver of the identified need and therefore represents the primary focus for non-network solutions.

Network support services could include services such as dispatchable demand (increases) or dispatchable storage (charging) within the supply area shown by Figure 2.

The amount of network support that Powercor is seeking from a non-network option by summer 2028-29 is 32 MW as shown in Table 10. There is also a discretion to provide network support earlier in summer 2027-28, at a level of 26 MW.

Table 10: Network support requirements from a non-network solution

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reverse power overload - minimum demand below 'N-1' emergency rating										
MW load increase requirement	0	0	26	32	39	46	52	56	63	69

The network support requirement is forecast to increase to 69 MW by 2035.

The duration of the service when dispatched is up to 4 hours per single contingency event, expected to be no more than 8 hours per annum in total.

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

4.2 Submission requirements

Submissions should include detailed technical information, proposed delivery timelines, indicative costings, dispatchability characteristics, and evidence of commercial viability. Providers should indicate the level of support service achievable to meet the identified need.

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

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

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

For further details on Powercor’s processes for engaging and consulting with non-network service providers, and for investigating, developing, assessing and reporting on non-network options as alternatives to network augmentation, please refer to the Industry Engagement Strategy and other relevant documentation at the link, [Powercor Industry Engagement Document.]

5. Description of potential credible options

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

- **Option 1** – Do nothing (base case);
- **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 of these options (except for Option 1) could address the identified need (at least in part).

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 is expected to lead 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 4 for the supply reliability risk associated with the capacity limitations, the value of the EUE risk associated with the “Do nothing” option (with 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).

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.

5.2 Option 2 – Non-network solution

Credible non-network solutions may be contracted to provide network support services from within the distribution or subtransmission networks serviced by TGTS, to deliver the services described in chapter 4, thereby addressing the identified need (at least in part). That chapter details the required technical characteristics as well as the maximum network support payments potentially available to a non-network service provider, based on the current view of the preferred network option.

Network support may also be combined with suitable network augmentation components to defer or reduce the scope of a credible network option. Non-network solutions could include dispatchable battery storage (charging during reverse power) or demand response (customer load increase).

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

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 9 to increase the capacity on TGTS to accommodate higher maximum demand and greater reverse power flows, thereby addressing the identified need in full.

Figure 9: TGTS transmission connection assets simplified single line diagram after Option 3

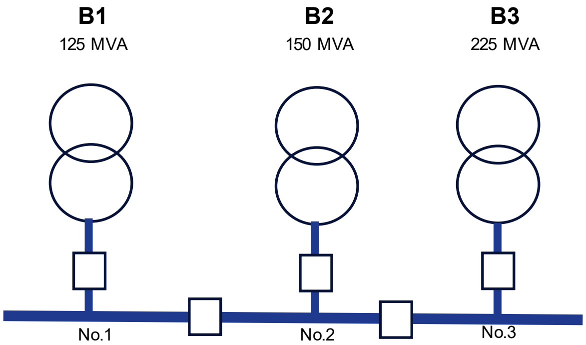


Table 11 provides a summary of the expected capability of TGTS for (N) and (N-1) conditions, following the completion of Option 3.

Table 11: 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).

This option meets the identified need by alleviating the supply capacity risk and removing all the expected unserved energy over the next ten years. Based on this, the optimal timing for commissioning the new transformer is by summer 2028-29, with a construction timetable of two years.

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

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

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

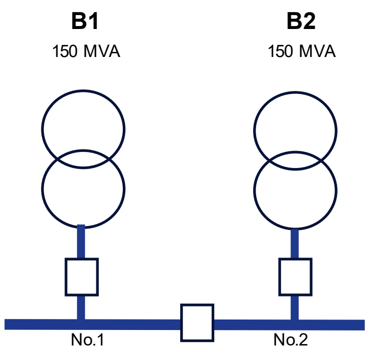


Table 12 provides a summary of the expected capability of TGTS for (N) and (N-1) conditions, following the completion of Option 4.

Table 12: 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) 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).

This option only meets the identified need in part by alleviating the supply capacity risk and removing some of the expected unserved energy over the next ten years. Based on this, the optimal timing for commissioning the replacement transformer is no earlier than summer 2028-29, with a construction timetable of two years.

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

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

6. Proposed assessment methodology

This chapter discusses the proposed assessment methodology for the net present value (NPV) assessment of options under this RIT-T, which will form the key focus on the PADR assessment, including:

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

6.1 Key assessment parameters

6.1.1 Value of customer reliability

The cost of EUE is calculated using a value of customer reliability (VCR), which is an estimate of the value electricity consumers put on having a reliable electricity supply. Powercor has applied locational VCR values based on the estimates in the Australian Energy Regulator's (AER) revised Values of Customer Reliability Review published in December 2025[20]. 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 TGTS VCR of $38,403/MWh.

6.1.2 Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. A real, 7.0 per cent, commercial discount rate is used at TGTS, aligned with AEMO's 2025 inputs, assumptions and scenarios report (IASR)[21]. For the sensitivities we use 10.0 per cent for the high bound, and 4.69 per cent for the low bound (representing a regulatory discount rate).

6.1.3 Assessment period

It is necessary to apply a cost-benefit analysis assessment period commensurate with the options being evaluated to address the identified need. Powercor intends to undertake the NPV analysis 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 will be 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.

6.2 Approach to cost estimation for network options

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

The costs presented in this PSCR are comprehensive including escalations, overheads, financing charges and management reserve (contingency risk). All cost estimates are escalated to real 2025 dollars based on the information available at the time of preparing this report.

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

[21] 2025 Inputs, Assumptions and Scenarios Report, Table 31, AEMO August 2025.

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.

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.

6.3 Materiality of market benefits

The RIT-T instrument requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the RIT-T proponent can demonstrate that[22]:

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

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

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 costs for parties, other than the RIT-T proponent**, as there is no other known investment, either generation or transmission, that will be affected by any option considered.
- **Changes in Australia's greenhouse gas emissions**, as changes in greenhouse gas emissions from changes in generation dispatch, renewable energy generation curtailment, or levels of SF_6 emissions from high-voltage switchgear, are considered to be negligible and unlikely to be a material class of market benefits for any of the credible options.
- **Change in network losses**, as changes in network losses are considered to be negligible in comparison to other market benefits considered in this RIT-T and unlikely to be a material class of market benefits for any of the credible options, nor change the ranking of options considered.
- **Additional option value**, as we expect that the costs of modelling option value will be disproportionate to any benefits and that there will be limited option value outside of anything captured in the scenario analysis (to the extent that timing or scope of options components, including any non-network components, varies across reasonable scenarios).
- **Changes in ancillary services costs**, as the options are not expected to impact on the demand for and supply of ancillary services.
- **Differences in the timing of expenditure**, as the timing of other unrelated expenditure is not expected to be impacted by the options considered in this assessment.
- **Avoided unrelated network expenditure**, as we do not expect the options to affect other proposed network expenditure.
- **Changes in safety costs**, as the identified need is not driven by network asset condition. Therefore, this market benefit was not quantified as it was not considered to be relevant with respect to differentiating between options that address the identified need.
- **Competition benefits**, as there is no competing generation affected by the limitations and risks being addressed by the options considered for this RIT-T.

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

7. Submissions and next steps

7.1 Request for submissions

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

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

Richard Robson

Manager Subtransmission Planning and Major Connections, Powercor

rittenquiries@powercor.com.au

The consultation on this PSCR is open for 12 weeks, consistent with the NER requirements[23].

Submissions are due on or before 11th September 2026.

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

7.2 Next steps

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

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

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

Powercor intends to move to the next stage of the RIT-T in the third quarter of 2026.

It should be noted that the estimated capital cost of the most expensive credible option to address the identified need in this RIT T is less than the $54 million[24] threshold for mandatory publication of a PADR. In accordance with the National Electricity Rules, where the estimated capital cost is below this threshold, Powercor may elect to proceed directly to a Project Assessment Conclusions Report (PACR) only where:

- no submissions identify a credible non-network option, and
- there is no material change in the identified need, credible options, or input assumptions.**

[23] NER, clause 5.16.4(g).

[24] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test, Australian Energy Regulator (AER), 12 November 2024

8. Appendix A – RIT-T compliance checklist

This appendix sets out a checklist in Table 13 which demonstrates the compliance of this PSCR with the requirements of clause 5.16.4(b) of the NER, version 247.

Table 13: PSCR RIT-T compliance checklist

A RIT-T proponent must prepare a report which must include:	Chapter
(1) a description of the identified need.	Chapter 2
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary).	Chapter 3
(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile.	Chapter 4
(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan.	Not applicable
(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options.	Chapter 5
(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Chapter 5 & 6

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

Table 14: AER guidelines PSCR compliance checklist

Summary of the requirements	Chapter
3.2.5 A RIT-T proponent must consider social licence issues in the identification of credible options. A RIT proponent should include information in its RIT reports about when and how social licence considerations have affected the identification and selection of credible options.	Chapter 5
3.4.3 The value of emissions reduction (VER), reported in dollars per tonne of emissions (CO2 equivalent), is used to value emissions within a state of the world. A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.	Not applicable
3.5A.1 Where the estimated capital costs of the preferred option exceeds $103 million, a RIT-T proponent must, in a RIT-T application: • outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T • for all credible options (including the preferred option), either – apply the cost estimate classification system published by the AACE, or – if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.	Not applicable
3.5A.2 For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied • the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance.	Chapter 6
3.5 In the RIT-T, costs must include the following classes: Costs incurred in constructing or providing the credible option Operating and maintenance costs over the credible option’s operating life Costs of complying with relevant laws, regulations and administrative requirements For, asset replacement projects or programs, there are costs resulting from removing and disposing of existing assets, which a RIT-T assessment should recognise. RIT-T proponents should include these costs in the costs of all credible options that require removing and disposing of retired assets. For completeness, the RIT-T proponent would exclude these costs from the 'BAU' base case.	Chapter 5

Summary of the requirements	Chapter
3.5.3 The RIT-T proponent is required to provide the basis for any social licence costs in its RIT-T reports and may choose to refer to best practice from a reputable, independent and verifiable source.	Not applicable
3.6 RIT-T proponents are required to apply classes of market benefits consistently across all credible options.	Chapter 6
3.7.3 When calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to: • include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome: • direct emissions from generation • direct emissions other than from generation estimate the change in annual emissions (once identified in accordance with this Guideline) between the base case and the credible option, and multiplying this change by the annual VER to arrive at the annual benefit from changes in Australia's greenhouse gas emissions.	Not applicable
3.8.2 Where the estimated capital cost of the preferred option exceeds $103 million (as varied in accordance with an applicable cost threshold determination), a RIT-T proponent must undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.	Not applicable
3.9.4 If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and how the level or quantum of the contingency allowance was determined.	Not applicable
3.11.2 Where a concessional finance agreement is included, the RIT-T proponent is required to provide sufficient detail about the concessional finance agreement to justify an agreement's inclusion and such that it can articulate how the value of the concession is to or would be shared with consumers. If a proponent seeks to include an unexecuted concessional finance agreement in the RIT-T, they must undertake sensitivity testing for the scenario the agreement doesn't eventuate.	Not applicable
4.1 RIT-T proponents are required to describe in each RIT-T report • how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement • how they plan to engage with these stakeholder groups, or • why this project does not require community engagement.	Chapter 5