Keilor Terminal Station Capacity Constraint

RIT-T Stage 2: Project Assessment Draft Report (PADR)

Executive summary

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and Powercor Australia Ltd. (**Powercor**), are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, servicing more than 384,000 and 945,000 customers respectively, within Melbourne's northern and western greater metropolitan area, and in central western regional Victoria.

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

In Victoria, the DNSPs have responsibility for planning and directing augmentation of the transmission connection assets that connect their distribution systems to the Victorian shared transmission system. This report relates to proposed investment on the transmission connection assets at Keilor Terminal Station (**KTS**) and as such, is subject to a regulatory investment test for transmission (**RIT-T**). KTS supplies electricity to parts of the JEN (the lead proponent of this RIT-T) and Powercor electricity distribution networks.

This project assessment draft report (**PADR**) is the second stage of the **Keilor Terminal Station Capacity Constraint RIT-T** consultation process and has been jointly prepared by JEN and Powercor in accordance with the requirements of clause 5.16 of the National Electricity Rules (**NER**)[1] and section 4.2 of the RIT-T Application Guidelines[2].

Identified Need

The identified need for this RIT-T is to deliver market benefits by maintaining electricity supply reliability and mitigating forecast increases in expected unserved energy (**EUE**) for those customers supplied from KTS, while enabling the connection of new major customer data-centre load within the supply area.

KTS supplies electricity to approximately 196,275 customers, with the supply area including major geographic centres such as Sunbury, Sydenham, Tullamarine, Airport West, St. Albans, Woodend, Gisborne, Pascoe Vale, Essendon, Keilor, Sunshine and Braybrook.

Electricity demand at KTS is soon expected to be one of the fastest growing in Victoria, with more than nine recent major customer data-centre connection requests within the Tullamarine area, an industrial area which is currently serviced by the KTS 66 kV bus group 125 (**KTS (B1,2,5)**). If only one of these data-centre connections proceeds to full load, KTS will have exceeded its full capacity.

Due to the expected increase in demand in the supply area from the prospective major customer data-centre connections, and the current high utilisation of KTS at maximum demand, the level of EUE resulting from capacity limitations at KTS is forecast to grow if action is not taken, resulting in a deterioration of supply reliability for our customers.

Addressing this identified need by reducing the forecast EUE with a prudent level of investment in a network, non-network or standalone power system (**SAPS**) solution, is expected to result in a positive net economic benefit. The need for this investment has been foreshadowed in the Transmission Connection Planning Report (**TCPR**), published jointly by the Victorian DNSPs[3].

[1] National Electricity Rules, version 243, Australian Energy Market Commission (AEMC), 2026.

[2] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.

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

Potential credible options

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

- Option 1 - Do Nothing (base case). This is not considered a credible option going forward due to the associated EUE risk;
- Option 2 - Non-network or SAPS solution;
- Option 3 – Upgrade all three transformers at KTS (B1,2,5), and install a new third transformer at KTS (B3,4);
- Option 4 – Establish a new bus group KTS (B7,8,9) with three new 220/66 kV transformers;
- Option 5 - Establish a new 500/220/66 kV switchyard at Sydenham Terminal Station (SYTS); and
- Option 6 - Establish a new 220/66 kV terminal station..

The PSCR flagged Option 3 as the likely preferred network option that would maximise the net market benefits. The estimated capital cost of this investment option to address the identified need exceeds the trigger of $8 million[4] for undertaking a RIT-T. All of the network options identified in the PSCR are assessed in this PADR.

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

Assessment approach

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

Options assessment and draft conclusion

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

Table 1-1: 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	5
3	504	4,845	11,312	5,377	1
4	376	3,832	8,836	4,218	4
5	405	3,862	8,866	4,248	3
6	454	3,910	8,914	4,297	2

The cost-benefit economic evaluation assessment undertaken for this PADR has concluded that the proposed preferred option to address the identified need for this RIT-T is Option 3 being upgrade all three transformers at KTS (B1,2,5) and install a new third transformer at KTS (B3,4). This proposed preferred option is found to have

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

positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver $5,377 million in present value net economic benefits over the analysis period. The estimated capital cost of this option is $91 million (real, 2025) with an optimum timing of 2028-29. This option satisfies the requirements of the RIT-T.

Submissions

JEN and Powercor invite written submissions and enquiries on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "**Keilor Terminal Station Capacity Constraint RIT-T**" and directed to both:

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Manager Sub-transmission Planning and Major Connections

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The consultation on this PADR is open for 6 weeks. Submissions are due on or before 12 June 2026. Submissions will be published on the Australian Energy Market Operator (**AEMO**), JEN 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 PADR consultation period, JEN and Powercor will, having regard to any submissions received on the PADR, prepare and publish a project assessment conclusions report (**PACR**) including:

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

Publication of that report will conclude consultation on this RIT-T.

JEN and Powercor intend on publishing the PACR by end 2026.

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Glossary

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.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services customers covering north-west greater Melbourne.
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.
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.
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.
Stand Alone Power System (SAPS)	An embedded power system that operates disconnected (islanded) from the network.
System Normal condition ('N')	The condition where no network assets are under maintenance or forced outage, and the network is operating in a normal configuration.
Terminal Station	A substation facility that houses transmission connection assets, connecting the distribution network to the Victorian transmission system.
Transmission Connection Asset	Transmission assets within a terminal station that are under the planning responsibility of the distributors connected to those assets.
Value of Customer Reliability (VCR)	Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
POE10 (summer)	Refers to an average daily ambient temperature of 32.9ºC, 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..

Abbreviations

A.C.	Auto-Close
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AW	Airport West Zone Substation
BY	Braybrook Zone Substation
CB	Circuit Breaker
DNSP	Distribution Network Service Provider (distributor)
ES	Essendon Zone Substation
EUE	Expected Unserved Energy
GSB	Gisborne Zone Substation
JEN	Jemena Electricity Networks (Vic) Ltd
KTS	Keilor Terminal Station
kV	Kilo-Volts
MAT	Major Customer Zone Substation
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System Normal Condition
N.O.	Normally Open
N-1	Single Contingency Condition
NDT	Data Centre Zone Substation
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
PV	Pascoe Vale Zone Substation
RIT-T	Regulatory Investment Test for Transmission
SA	St Albans Zone Substation
SAPS	Stand Alone Power System
SBY	Sunbury Zone Substation

SHM	Sydenham Zone Substation
SSE	Sunshine Zone Substation
SYTS	Sydenham Terminal Station
TCPR	Transmission Connection Planning Report
TMA	Tullamarine Zone Substation
TMTS	Tullamarine Terminal Station (future)
WND	Woodend Zone Substation
VCR	Value of Customer Reliability

1. Introduction

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and Powercor Australia Ltd. (**Powercor**), are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, servicing more than 384,000 and 945,000 customers respectively, within Melbourne's northern and western greater metropolitan area, and in central western regional Victoria.

The regulatory investment test for transmission (**RIT-T**) is an economic cost-benefit test and consultation process used to seek, assess and rank potential investments capable of meeting an identified need. The purpose of a RIT-T is to identify the credible option that maximises the present value of net economic benefit (the preferred option). The process follows the requirements in clauses 5.15A and 5.16 of the National Electricity Rules (**NER**)[5].

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]. The RIT-T process is summarised in Figure 1-1, below.

JEN and Powercor are undertaking this RIT-T to evaluate options to maintain reliability of supply and to connect new major customer data-centre load within the Keilor Terminal Station (**KTS**) 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. The capital cost of the 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.

The project specification consultation report (**PSCR**) for the first stage of the **Keilor Terminal Station Capacity Constraint RIT-T** consultation was published in June 2025 in accordance with section 4.2 of the RIT-T Application Guidelines[7]. JEN and Powercor received no submissions for non-network proposals during the RIT-T PSCR consultation stage.

We have now published this project assessment draft report (**PADR**), representing the second stage of the **Keilor Terminal Station Capacity Constraint RIT-T** consultation process, in accordance with section 4.3 of the RIT-T Application Guidelines.

The structure of this PADR is as follows:

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

The need for investment has been foreshadowed in the Transmission Connection Planning Report (**TCPR**)[8], published jointly by the Victorian DNSPs.

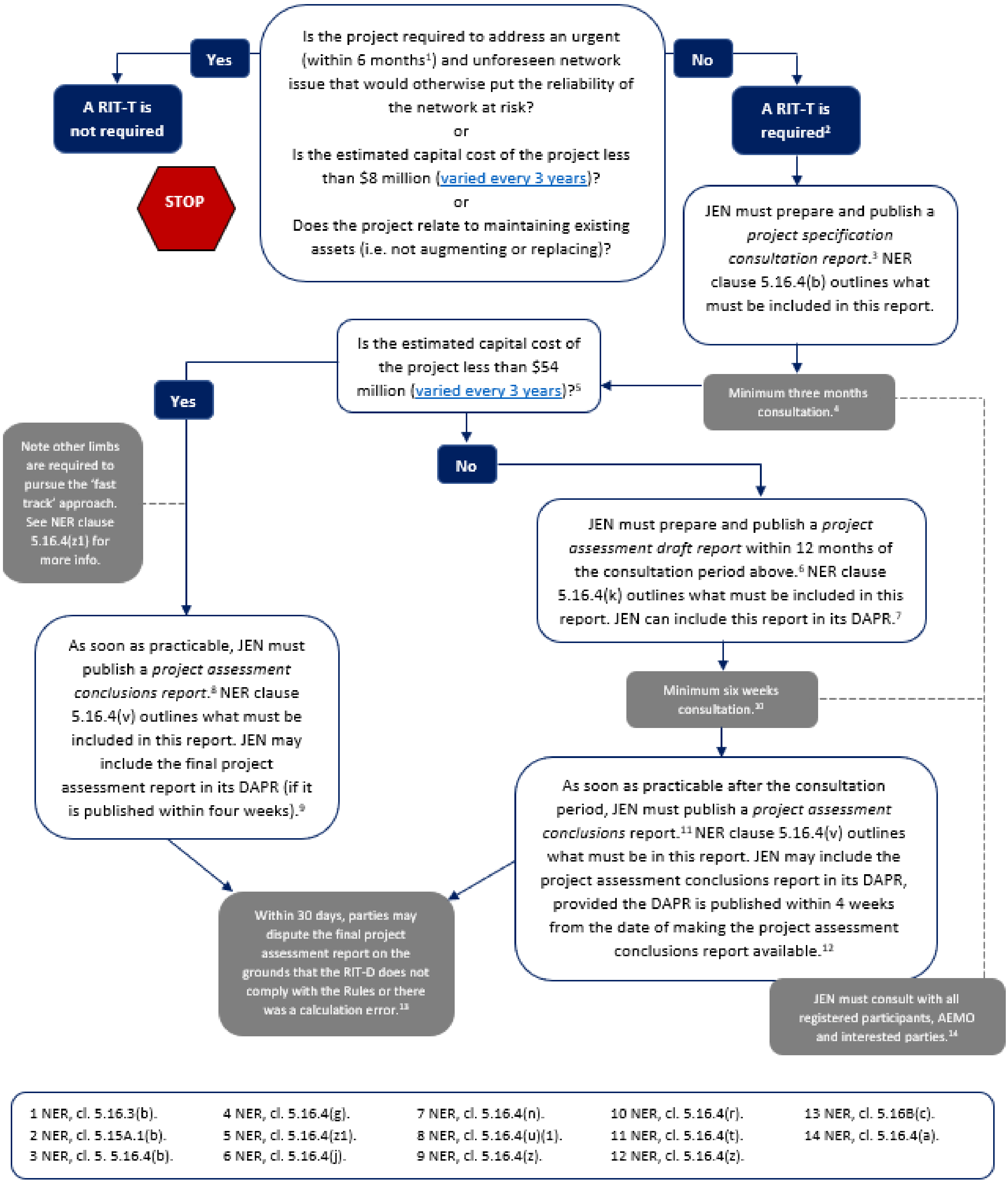
[5] National Electricity Rules, version 243, Australian Energy Market Commission (AEMC), 2026.

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

[7] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.

[8] Transmission Connection Planning Report, Victorian Distribution Network Service Providers, 2025.

Figure 1-1: RIT-T process flow chart



2. Description of the identified need

This chapter discusses the role of Keilor Terminal Station (**KTS**) in providing electricity network services and the identified need associated with its current and forecast capacity limitations. Quantification of the risk and costs associated with the forecast increase in Expected Unserved Energy (**EUE**) in the base case (i.e., the status-quo where no investment is undertaken) is also presented.

2.1 Supply area

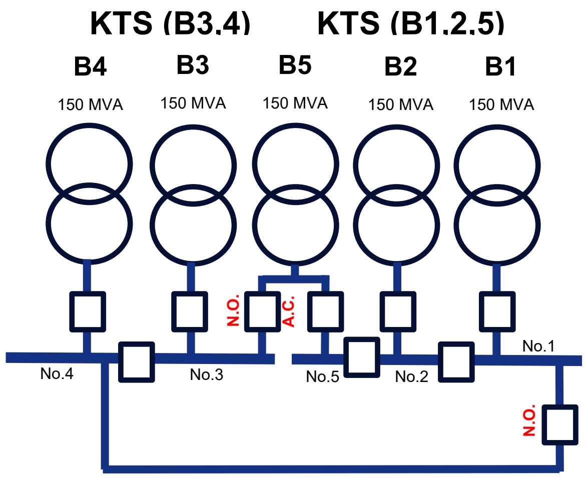
KTS is located in the north-west of Greater Melbourne. It operates at 220/66 kV and supplies major geographic centres such as Sunbury, Sydenham, Tullamarine, Airport West, St. Albans, Woodend, Gisborne, Pascoe Vale, Essendon, Keilor, Sunshine and Braybrook.

Electricity demand at KTS is soon expected to be one of the fastest growing in Victoria, with JEN recently receiving more than nine major customer data-centre connection requests within the Tullamarine area, an industrial area located north-east of KTS. If only one of these data-centre connections proceeds to full load, KTS will have exceeded its full capacity.

2.1.1 Electricity network servicing the supply area

KTS has five 150 MVA transformers and is a summer critical station. Under system normal conditions, the No.1, No.2 & No.5 transformers are operated in parallel as the KTS 66 kV bus group 125 (**KTS (B1,2,5)**) and supply the No.1, No.2 & No.5 66 kV buses. The No.3 & No.4 transformers are operated in parallel as a separate KTS 66 kV bus group 34 (**KTS (B3,4)**) and supply the No.3 & No.4 66 kV buses. The 66 kV bus 3-5 and bus 1-4 tie circuit breakers are operated in the normally open position to limit the maximum prospective fault levels on the five 66 kV buses to within switchgear ratings. For an unplanned transformer outage in the KTS (B3,4) group[9], the No.5 transformer will automatically change over from the KTS (B1,2,5) to the KTS (B3,4) group. Therefore, an unplanned transformer outage of any one of the five transformers at KTS will result in both the KTS (B1,2,5) and KTS (B3,4) groups being comprised of two transformers each. This is illustrated in Figure 2-1.

Figure 2-1: KTS 66 kV simplified single line diagram (existing)



The summer cyclic rating of KTS (B1,2,5) with all plant in service is 509 MVA and with one of its three 220/66 kV 150 MVA transformers out of service, reduces to 339 MVA noting that the B5 transformer is also used as an auto-changeover spare to support the KTS (B3,4) group. Hence the available capacity across these two bus groups are intricately linked.

[9] Specifically, either of the No.3 or No.4 transformers.

The summer cyclic rating of KTS (B3,4) with all plant in service is 331 MVA, and with one of its two 220/66 kV 150 MVA transformers out of service is maintained at 331 MVA, assuming the auto-change over from KTS (B1,2,5) is enacted to place KTS (B1,2,5) in an N-1 condition.

KTS has fourteen 66 kV sub-transmission line exits supplying seven JEN zone substations, four Powercor zone substations, and two major customer or data-centre substations.

2.1.2 Customer demand for electricity

More than 196,275 customers rely on KTS for their electricity supply. Residential customers consume 48 per cent of the total annual energy supplied from KTS as illustrated in Table 2-1. This is closely followed by commercial customers (40 per cent), and industrial customers (10 per cent).

Table 2-1: KTS net energy consumption (GWh per annum, 2024)

Customer Type	KTS (B1,2,5)	KTS (B3,4)	KTS Total	Proportion
Commercial	493	200	693	39.7%
Residential	403	429	832	47.6%
Industrial	135	32	167	9.5%
Agricultural	0	2	2	0.1%
Large Business > 10 MW	54	0	54	3.1%
Total	**1,085**	**663**	**1,748**	**100%**

There has been an unprecedented number of data-centre and major load connection enquiries in the KTS supply area over the last two years, with many enquiries needing feasibility assessments across multiple alternative locations within the service area. Some of the enquiries are now proceeding to formal connection applications and offers, with connection options frequently being tested by the applicants competitively across different distributors. Others are now proceeding to construction.

More than nine recent major customer data-centre connection requests have been received within this supply area. As a result, the proportion of energy consumed by the Large Business category for KTS (B1,2,5) (and for KTS as a whole) is expected to grow substantially over the next ten to fifteen years. If only one of these data-centre connections proceeds to full load, KTS will have exceeded its full capacity.

Section 6.2.2 provides an overview of the maximum demand forecasts that underpin the identified need, and which reflect the expected connection of these new data centre loads.

2.2 Identified need

There is forecast to be insufficient capacity to supply the forecast maximum demand at KTS with the existing transmission connection assets that are in place. This is likely to lead to a significant deterioration in supply reliability for customers supplied by this terminal station under system normal and single contingency conditions, and inhibit the connection of new major customer data centres within the supply area.

The identified need is to deliver market benefits from reduced expected unserved energy (**EUE**) by maintaining electricity supply reliability for customers supplied from KTS and to connect new major customer data-centre load within the supply area. Due to the expected increases in demand in the supply area from the prospective major customer data-centre connections, and the current high utilisation of KTS at maximum demand, the level of EUE resulting from capacity limitations at KTS is forecast to grow as demand increases, deteriorating supply reliability for our customers if action is not taken.

Addressing this identified need by reducing the forecast EUE with a prudent level of investment in a network, non-network or standalone power system (**SAPS**) solution, is expected to result in a positive net economic benefit.

There are two drivers of EUE at KTS - a lack of "N" capacity (with all plant in service), and a lack of "N-1" capacity (with one transformer out of service). We note that KTS has load transfer capability available at the distribution feeder level. This capability allows JEN and Powercor to manage risk in the short-term, by transferring load away from KTS to surrounding terminal stations using spare capacity through each distribution network, to reduce the level of EUE.

Table 2-2 summarises the forecast capacity limitations at KTS (B1,2,5), considering the impacts of the committed major customer data-centre connections load forecast on the overall demand at KTS (B1,2,5).

Table 2-2: Forecast capacity limitations at KTS (B1,2,5)

<table>
<tr><th>KTS (B1,2,5)</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th><th>2030</th><th>2031</th><th>2032</th><th>2033</th><th>2034</th><th>2035</th></tr>
<tr><td colspan="11">Load at risk above 'N' (MVA)</td></tr>
<tr><td>Summer POE10</td><td>0</td><td>67</td><td>141</td><td>197</td><td>197</td><td>198</td><td>204</td><td>209</td><td>209</td><td>207</td></tr>
<tr><td>Winter POE10</td><td>0</td><td>4</td><td>86</td><td>149</td><td>155</td><td>161</td><td>170</td><td>176</td><td>177</td><td>177</td></tr>
<tr><td>Summer POE50</td><td>0</td><td>18</td><td>90</td><td>147</td><td>146</td><td>147</td><td>152</td><td>157</td><td>157</td><td>155</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>0</td><td>56</td><td>119</td><td>124</td><td>130</td><td>138</td><td>145</td><td>146</td><td>146</td></tr>
<tr><td colspan="11">Time at risk above 'N' (h pa)</td></tr>
<tr><td>Summer POE10</td><td>0</td><td>4</td><td>24</td><td>58</td><td>58</td><td>59</td><td>63</td><td>67</td><td>67</td><td>65</td></tr>
<tr><td>Winter POE10</td><td>0</td><td>1</td><td>147</td><td>545</td><td>587</td><td>632</td><td>689</td><td>742</td><td>754</td><td>757</td></tr>
<tr><td>Summer POE50</td><td>0</td><td>2</td><td>6</td><td>30</td><td>29</td><td>30</td><td>32</td><td>35</td><td>35</td><td>34</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>0</td><td>45</td><td>328</td><td>361</td><td>401</td><td>463</td><td>510</td><td>521</td><td>522</td></tr>
<tr><td colspan="11">Load at risk above 'N-1' (MVA)</td></tr>
<tr><td>Summer POE10</td><td>96</td><td colspan="9">170</td></tr>
<tr><td>Winter POE10</td><td>14</td><td>160</td><td colspan="8">176</td></tr>
<tr><td>Summer POE50</td><td>47</td><td colspan="9">170</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>131</td><td colspan="8">176</td></tr>
<tr><td colspan="11">Time at risk above 'N-1' (h pa)</td></tr>
<tr><td>Summer POE10</td><td>26</td><td>210</td><td>528</td><td>903</td><td>899</td><td>909</td><td>942</td><td>974</td><td>975</td><td>959</td></tr>
<tr><td>Winter POE10</td><td>4</td><td>1186</td><td>2159</td><td>2814</td><td>2875</td><td>2941</td><td>3024</td><td>3087</td><td>3101</td><td>3103</td></tr>
<tr><td>Summer POE50</td><td>5</td><td>125</td><td>301</td><td>486</td><td>483</td><td>487</td><td>502</td><td>514</td><td>517</td><td>509</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>860</td><td>1814</td><td>2501</td><td>2554</td><td>2610</td><td>2696</td><td>2763</td><td>2779</td><td>2782</td></tr>
<tr><td colspan="11">Weighted EUE[10]</td></tr>
<tr><td>'N' EUE (MWh)</td><td>0.0</td><td>43.6</td><td>1,869</td><td>14,612</td><td>16,512</td><td>18,852</td><td>22,394</td><td>25,415</td><td>26,137</td><td>26,161</td></tr>
<tr><td>'N-1' EUE (MWh)</td><td>0.7</td><td>189.6</td><td>737.6</td><td>1,360</td><td>1,408</td><td>1,465</td><td>1,547</td><td>1,612</td><td>1,626</td><td>1,623</td></tr>
<tr><td>Total EUE[11] (MWh)</td><td>0.7</td><td>233.2</td><td>2,607</td><td>15,973</td><td>17,920</td><td>20,317</td><td>23,941</td><td>27,027</td><td>27,763</td><td>27,784</td></tr>
<tr><td>Value of EUE ($m[12])</td><td>0.03</td><td>9.77</td><td>109.3</td><td>669.3</td><td>751.0</td><td>851.4</td><td>1,003</td><td>1,133</td><td>1,163</td><td>1,164</td></tr>
</table>

[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.

[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 throughout the year.

[12] Real, 2025.

The value of EUE is derived by multiplying the level of EUE (in MWh) by an estimate of the Value of Customer Reliability (**VCR**). We have adopted the AER's estimate of VCR published in December 2024 as discussed further in section 6.2.6.

The EUE is estimated to have a value to consumers of around $9.77 million (real, 2025) by 2027, rising rapidly thereafter as the N rating is exceeded to $1,164 million by 2035.

The key elements of the "Do Nothing" supply reliability risk under the status-quo are shown in Figure 2-2 at KTS (B1,2,5), considering the impacts of available transfer capacity.

Figure 2-2: KTS (B1,2,5) EUE risk costs (including impact of load transfer capability)

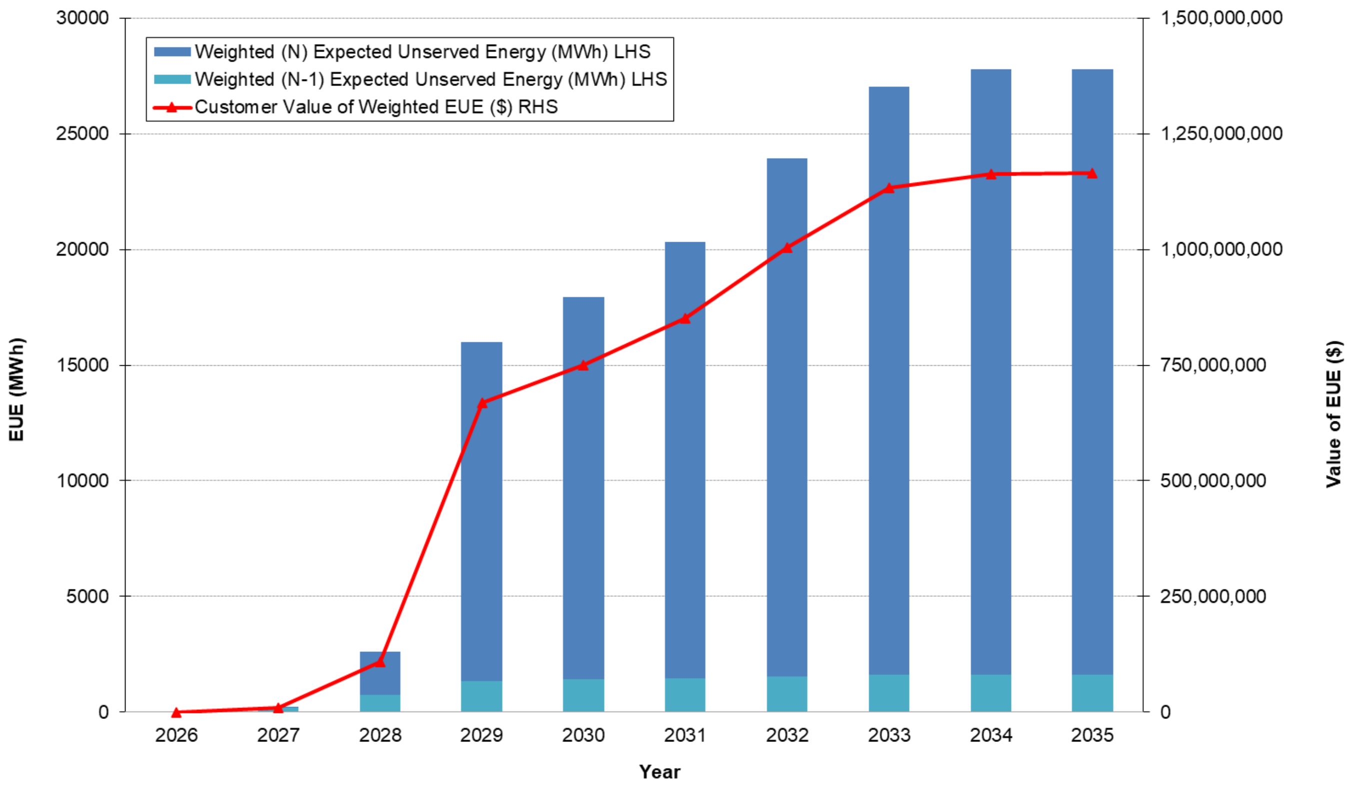


Table 2-3 summarises the forecast capacity limitations at KTS (B3,4), considering the impacts of the major customer data-centre connections load forecast on the overall demand at KTS (B3,4).

Table 2-3: Forecast capacity limitations at KTS (B3,4)

KTS (B3,4)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load at risk above 'N' (MVA)										
Summer POE10	0	18	99	102	103	106	111	116	119	122
Winter POE10	0	0	35	43	50	57	66	73	78	83
Summer POE50	0	0	75	77	79	82	87	92	94	96
Winter POE50	0	0	33	41	48	55	63	71	76	81
Time at risk above 'N' (h pa)										
Summer POE10	0	2	30	31	32	35	39	43	46	48
Winter POE10	0	0	47	56	76	110	156	206	249	291
Summer POE50	0	0	13	15	16	17	21	25	27	28
Winter POE50	0	0	32	46	67	99	142	188	231	273
Load at risk above 'N-1' (MVA)										
Summer POE10	101	167								
Winter POE10	0	0	188							
Summer POE50	0	159	167							
Winter POE50	0	0	188							
Time at risk above 'N-1' (h pa)										
Summer POE10	146	867	2302	2351	2378	2437	2534	2622	2677	2713
Winter POE10	0	0	3564	3626	3682	3735	3795	3844	3878	3913
Summer POE50	0	497	1865	1902	1928	1967	2057	2152	2207	2244
Winter POE50	0	0	3408	3482	3548	3611	3678	3739	3780	3820
Weighted EUE[13]										
'N' EUE (MWh)	0.0	3.7	1,009	1,355	1,772	2,389	3,380	4,588	5,638	6,854
'N-1' EUE (MWh)	2.9	53.3	1,268	1,352	1,428	1,508	1,605	1,695	1,756	1,813
Total EUE[14] (MWh)	**2.9**	**57.0**	**2,277**	**2,707**	**3,200**	**3,897**	**4,985**	**6,283**	**7,394**	**8,667**
Value of EUE ($m[15])	**$0.14**	**$2.72**	**$108.7**	**$129.2**	**$152.7**	**$186.0**	**$237.9**	**$299.8**	**$352.8**	**$413.6**

The EUE is estimated to have a value to consumers of around $2.72 million (real, 2025) by 2027, rising to $413.6 million by 2035.

The key elements of the "Do Nothing" supply reliability risk under the status-quo are shown in Figure 2-3 at KTS (B3,4), considering the impacts of available transfer capacity.

[13] 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.

[14] 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 throughout the year.

[15] Real, 2025.

Figure 2-3: KTS (B3,4) EUE risk costs (including impact of load transfer capability)

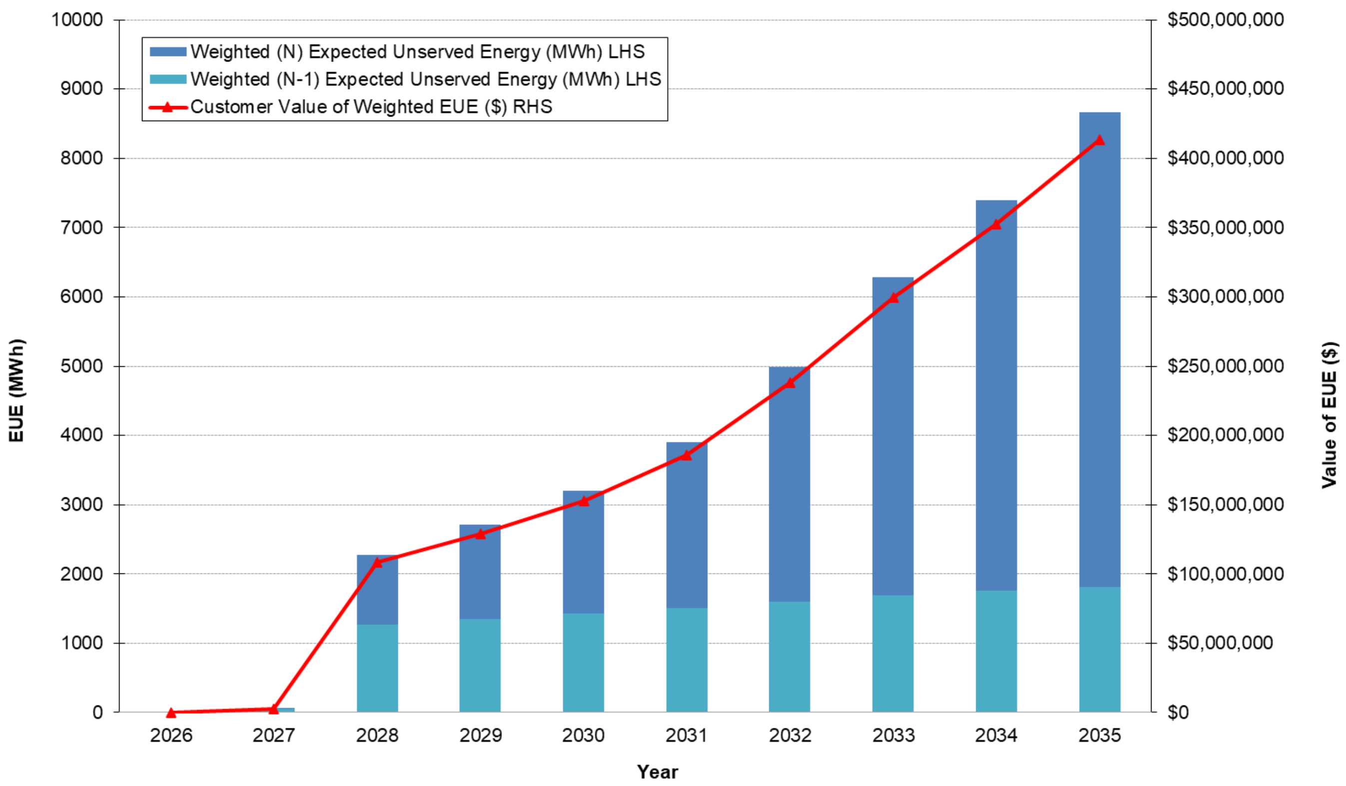


Table 2-4 summarises the value of the EUE (as a combined total from Table 2-2 and Table 2-3).

Table 2-4: Forecast EUE at KTS (Do Nothing)

KTS EUE (MWh pa)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	8.6	1,693	11,804	13,777	16,302	20,276	24,084	25,754	26,949
POE50 (N-1)	0.2	187.7	1,881	2,565	2,686	2,820	2,993	3,145	3,220	3,273
POE10 (N)	-	137.8	5,645	25,680	28,801	32,766	38,602	43,814	45,825	47,171
POE10 (N-1)	11.2	371.4	2,297	3,057	3,183	3,329	3,521	3,684	3,761	3,816
Total (Weighted[16])	**3.5**	**290**	**4,885**	**18,680**	**21,120**	**24,214**	**28,926**	**33,310**	**35,158**	**36,451**

Table 2-5: Forecast weighted value of EUE at KTS (Do Nothing)

KTS EUE ($m real, 2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	0.16	13.0	218.9	837.0	946.4	1,085	1,296	1,493	1,575	1,633

[16] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE

3. Credible options assessed

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

The potentially credible options considered to address the identified need for the supply area include:

- **Option 1** - Do Nothing (base case) continues to supply customers serviced by KTS 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. This is not considered a credible option going forward due to the associated EUE risk;
- **Option 2** - Non-network or SAPS solutions is to contract network support services, within the distribution networks serviced by KTS, to reduce the net maximum demand on KTS and address the identified need. Network support services could include services such as voluntary load reduction (e.g. demand response), aggregated distributed energy resources (e.g. virtual power plants), or larger-scale dispatchable embedded storage and/or generation resources;
- **Option 3** - Upgrade all three transformers at KTS (B1,2,5), and install a new third transformer at KTS (B3,4) to increase the thermal capacity of the KTS transmission connection assets to address the identified need. There is provision to accommodate these transformers at KTS;
- **Option 4** - Establish a new bus group KTS (B7,8,9) with three new 220/66 kV transformers to reduce the net maximum demand on KTS (B1,2,5) and KTS (B3,4) to address the identified need. There is provision to accommodate these new transformers and switchyard at KTS;
- **Option 5** - Establish a new 500/220/66 kV switchyard at Sydenham Terminal Station (SYTS) to reduce the maximum demand on KTS, transferring load to SYTS by re-arranging the existing sub-transmission network, thereby addressing the identified need. There is provision to accommodate these new transformers and switchyard at SYTS; and
- **Option 6** - Establish a new 220/66 kV terminal station (TMTS) to reduce the maximum demand on KTS, transferring load to the new terminal station by re-arranging the existing sub-transmission network, thereby addressing the identified need. JEN owns a greenfield property to accommodate this new terminal station.

The PSCR flagged Option 3 as the likely preferred network option that maximises the net market benefits.

All of the network options would either increase the thermal capacity of KTS or result in additional capacity at another (or new) terminal station. Table 3-1 below summarises the new thermal capacity ratings that would result from the four network options, compared to the base case in which no investment is undertaken.

Table 3-1: Thermal capacity ratings of each option (MVA)

Rating	Option 1 (base case)		Option 3		Option 4	Option 5 & 6
	KTS (B1,2,5)	KTS (B3,4)	KTS (B1,2,5)	KTS (B3,4)	KTS (B7,8,9)	SYTS / TMTS
Summer (N)	509	331	795	490	795	795
Summer (N-1)	339	331	530	331	530	530
Winter (N)	509	375	879	560	879	879
Winter (N-1)	353	375	586	375	586	586

The different options will all result in lower EUE than in the base case, although the extent of the reduction varies across the options due to the differences in the additional thermal capacity ratings they provide. JEN and Powercor consider that all options reduce EUE to a level consistent with the identified need for this RIT-T.

4. Submissions to the consultation

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

In June 2025, JEN and Powercor published the project specification consultation report (PSCR), being the first stage of this RIT-T process, which provided an opportunity for non-network providers to submit proposals for alternative solutions to address the identified need.

During this period of consultation on the PSCR, no non-network proposals or submissions were received from interested stakeholders. As a consequence, Option 2 from the PSCR (i.e., non-network or SAPS solutions) is no longer considered a credible option for the purposes of this PADR in addressing the identified need.

Furthermore, as the capital cost of the preferred network option is greater than the trigger threshold of $54 million[17] for publication of a project assessment draft report, we are undertaking a second round of consultation for this RIT-T by publishing this PADR.

[17] 2024 cost thresholds review for the Regulatory Investment Test | Australian Energy Regulator (AER).

5. Credible options costs and benefits

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

5.1 Option 1 - Do nothing

The ”Do-nothing” option involves continuing to supply customers serviced by KTS without any intervention to manage EUE. This is expected to lead to significant supply interruptions and unserved energy under both “N” (system normal) and “N-1” (single contingency) conditions.

As detailed in Table 2-5, the total combined value of the EUE risk associated with the “Do nothing” option is forecast to increase from $0.16 million in 2025-26 to $218.9 million in 2027-28, to $1,633 million by 2034-35 (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 or SAPS solution

Non-network or SAPS options contracted to provide network support services from within the distribution or sub-transmission networks serviced by KTS, to reduce the net maximum demand on KTS (i.e., reduce the EUE) thereby addressing the identified need (at least in part).

Network support services could include services such as voluntary load reduction (demand response), aggregated distributed energy resources (virtual power plants), or larger-scale dispatchable (or standby) embedded storage and/or generation resources.

In June 2025, JEN and Powercor published the project specification consultation report (PSCR), being the first stage of this RIT-T process which provided an opportunity for non-network providers to submit proposals for alternative solutions to address the identified need.

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

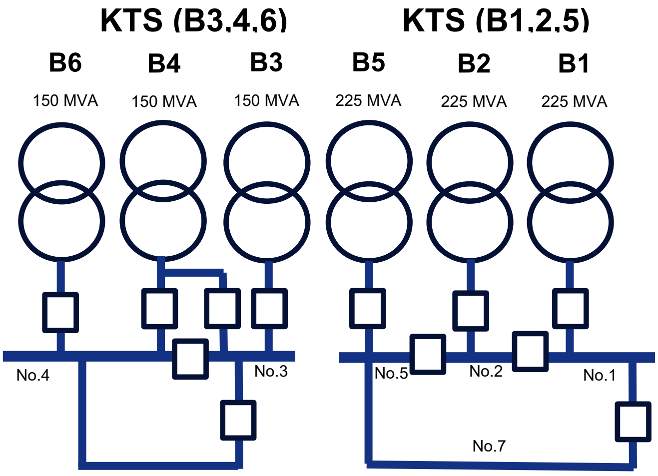
As a consequence, this option has been considered but not progressed on the basis that it is not a credible option for the purposes of addressing the identified need for this RIT-T.

5.3 Option 3 - Upgrade all three transformers at KTS (B1,2,5), and install a new third transformer at KTS (B3,4)

This option involves installing a third B6 150 MVA 220/66 kV transformer at KTS (B3,4) to increase the thermal capacity ratings of the transmission connection assets at this terminal station. There is already provision in the original design of the terminal station to accommodate this transformer. Works are also required to connect B6 into the 220 kV shared transmission assets.

This option also involves replacing the B1, B2 and B5 150 MVA 220/66 kV transformers in-situ at KTS (B1,2,5) with 225 MVA units to increase the thermal capacity ratings of the transmission connection assets at this terminal station, and establishment of a new No.7 66 kV bus. A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 5-1.

Figure 5-1: KTS 66 kV simplified single line diagram (Option 3)



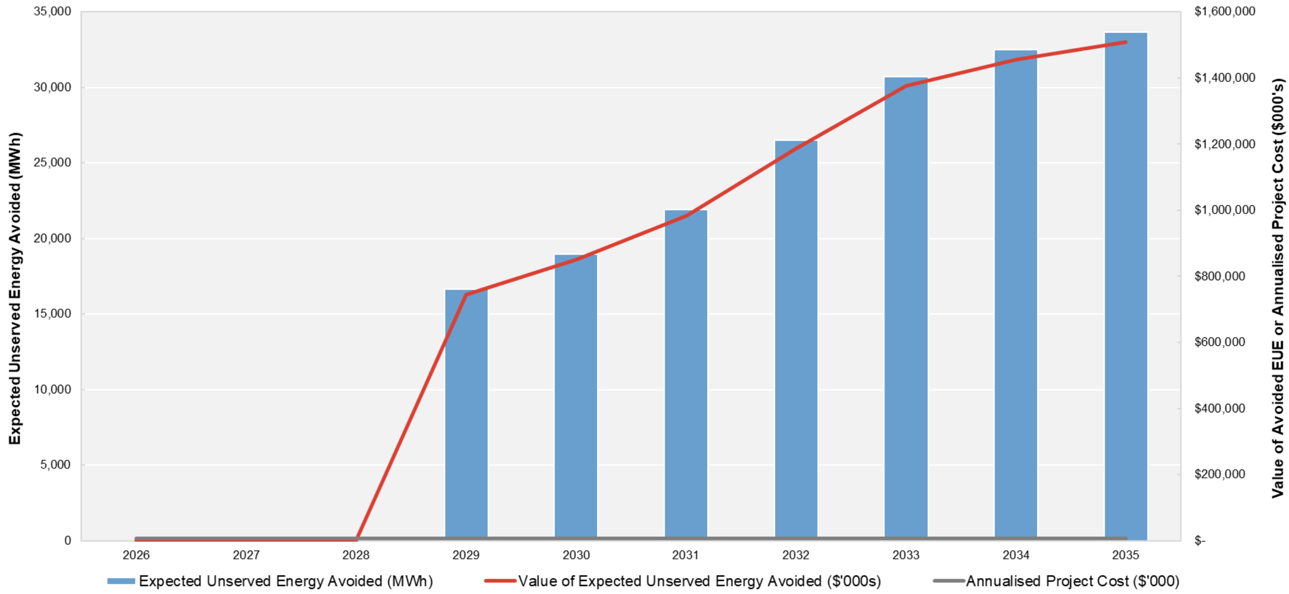
The scope of work required for this option includes:

- Relocate the existing B1 transformer to the B6 position with neutral reactor, and commission as B6 with a new 220 kV circuit breaker in Bay O;
- Switch existing B4 transformer across the No.3 and No. 4 66 kV buses with a new 66 kV circuit breaker;
- Remove the existing B2 transformer, de-energise existing B5 transformer, and relocate existing 220 kV shunt reactor No.1;
- Supply and install three new 225 MVA 220/66 kV transformers (B1, B2 and B5) with new 66 kV circuit breakers;
- Establish new 66 kV bus No. 7 and No.4 bus extension with new 66 kV circuit breakers;
- Civil, structural, station services and earthing works to support the above;
- Install and modify remaining primary, protection, monitoring, control and communication equipment.

The estimated capital cost of this network option is $91 million (real, 2025) and an ongoing operations and maintenance cost of $0.9 million per annum, which has a present value total cost of $83.3 million and an annualised cost of $7.5 million. Based on this annualised cost, the optimal timing of this option based on the forecast weighted value of EUE at KTS (as set out in Table 2-5) able to be avoided, is before summer 2027-28.

Figure 5-2 identifies the optimal timing of Option 3 based on the avoided EUE risk and its annualised cost.

Figure 5-2: Optimal timing based on avoided risks and annualised costs (Option 3)



However, this option has an estimated construction period of two to three years, therefore this limits the optimum timing to summer 2028-29.

Table 5-1 lists the forecast EUE at KTS with Option 3 in service, based on its optimum timing.

Table 5-1: Forecast EUE at KTS (Option 3)

KTS EUE (MWh pa)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	8.6	1,693	-	-	-	-	-	-	-
POE50 (N-1)	0.2	187.7	1,881	1,979	2,093	2,216	2,362	2,505	2,603	2,694
POE10 (N)	-	137.8	5,645	-	-	-	-	-	-	-
POE10 (N-1)	11.2	371.4	2,297	2,187	2,308	2,441	2,610	2,760	2,864	2,963
Total (Weighted[18])	3.5	290	4,885	2,041	2,158	2,283	2,436	2,581	2,681	2,775

Table 5-2 lists the forecast value of EUE at KTS with Option 3 in service, based on its optimum timing.

Table 5-2: Forecast value of EUE at KTS (Option 3)

KTS EUE ($m, real 2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	0.16	13.0	218.9	91.5	96.7	102.3	109.2	115.7	120.1	124.3

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

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

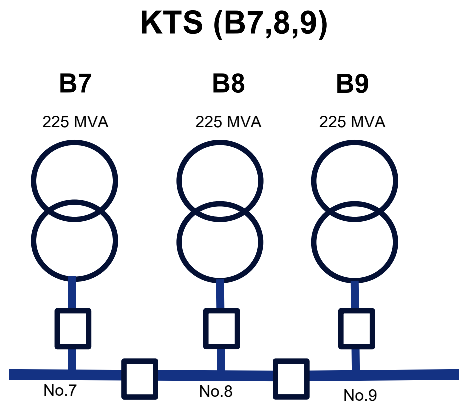
[18] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE

5.4 Option 4 - Establish a new bus group KTS (B7,8,9) with three new 66 kV transformers

This option involves installing a 66 kV switchyard within KTS with three new 225 MVA 220/66 kV transformers being KTS (B7,8,9), to increase the thermal capacity ratings of the transmission connection assets at this terminal station. There is likely to be available space within the terminal station to accommodate this new switchyard. Works are also required to connect B7, B8 and B9 into the 220 kV shared transmission assets. A variant of this option being considered is 2 x 500 MVA 500/132 kV transformers.

A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 5-3.

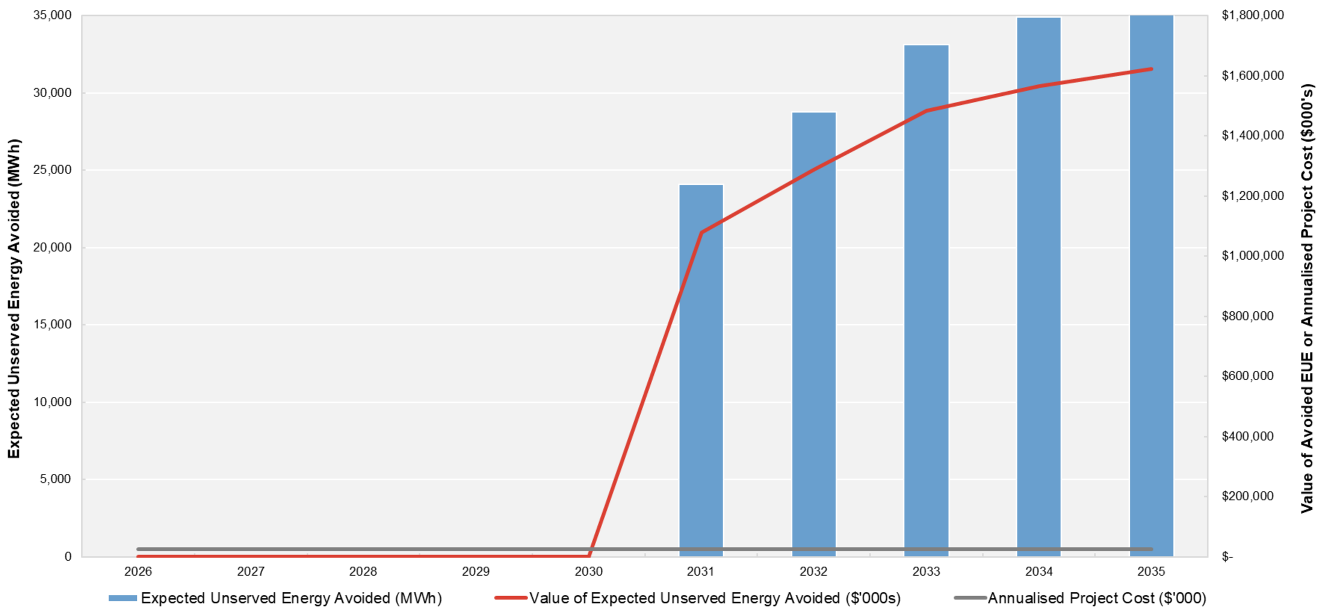
Figure 5-3: KTS (B7,8,9) 66 kV simplified single line diagram (Option 4)



The estimated capital cost of this network option is $290 million (real, 2025) and an ongoing operations and maintenance cost of $2.9 million per annum, which has a present value total cost of $229 million and an annualised cost of $25.3 million. Based on this annualised cost, the optimal timing of this option based on the forecast weighted value of EUE at KTS (as set out in Table 2-5) able to be avoided, is before summer 2027-28.

Figure 5-4 identifies the optimal timing of Option 4 based on the avoided EUE risk and its annualised cost.

Figure 5-4: Optimal timing based on avoided risks and annualised costs (Option 4)



However, this option has an estimated construction period of four to five years, therefore this limits the optimum timing to summer 2030-31.

Table 5-3 lists the forecast EUE at KTS with Option 4 in service, based on its optimum timing.

Table 5-3: Forecast EUE at KTS (Option 4)

KTS EUE (MWh pa)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	8.6	1,693	11,804	13,777	-	-	-	-	-
POE50 (N-1)	0.2	187.7	1,881	2,565	2,686	130.4	162.0	195.8	221.6	248.3
POE10 (N)	-	137.8	5,645	25,680	28,801	-	-	-	-	-
POE10 (N-1)	11.2	371.4	2,297	3,057	3,183	149.5	185.0	219.5	245.9	274.4
Total (Weighted[19])	3.5	290	4,885	18,680	21,120	136	169	203	229	256

Table 5-4 lists the forecast value of EUE at KTS with Option 4 in service, based on its optimum timing.

Table 5-4: Forecast value of EUE at KTS (Option 4)

KTS EUE ($m, real 2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	0.16	13.0	218.9	837.0	946.4	6.1	7.6	9.1	10.3	11.5

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

Social licencing risks are considered moderate for this option as even though it only involves work within an existing established substation, the scale of the works is substantial requiring works at 500 kV. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

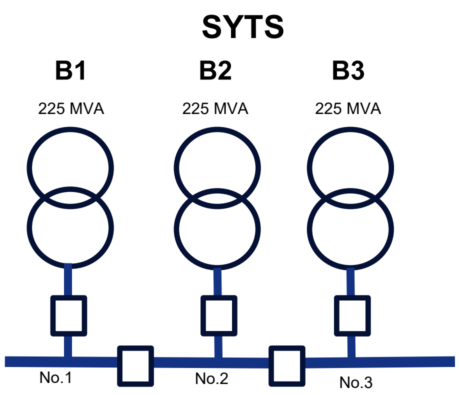
[19] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE

5.5 Option 5 - Establish a new 500/220/66 kV switchyard at Sydenham Terminal Station (SYTS)

This option involves installing a 220kV and 66 kV switchyard within SYTS with three new 225 MVA 220/66 kV transformers, to establish new transmission connection assets at this terminal station. There is space within the terminal station to accommodate these new switchyards. Works are also required to augment and connect B1 B2, and B3 into the 500 kV shared transmission assets including via two new A1 and A2 1000 MVA 500/220 kV transformers.

A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 5-5.

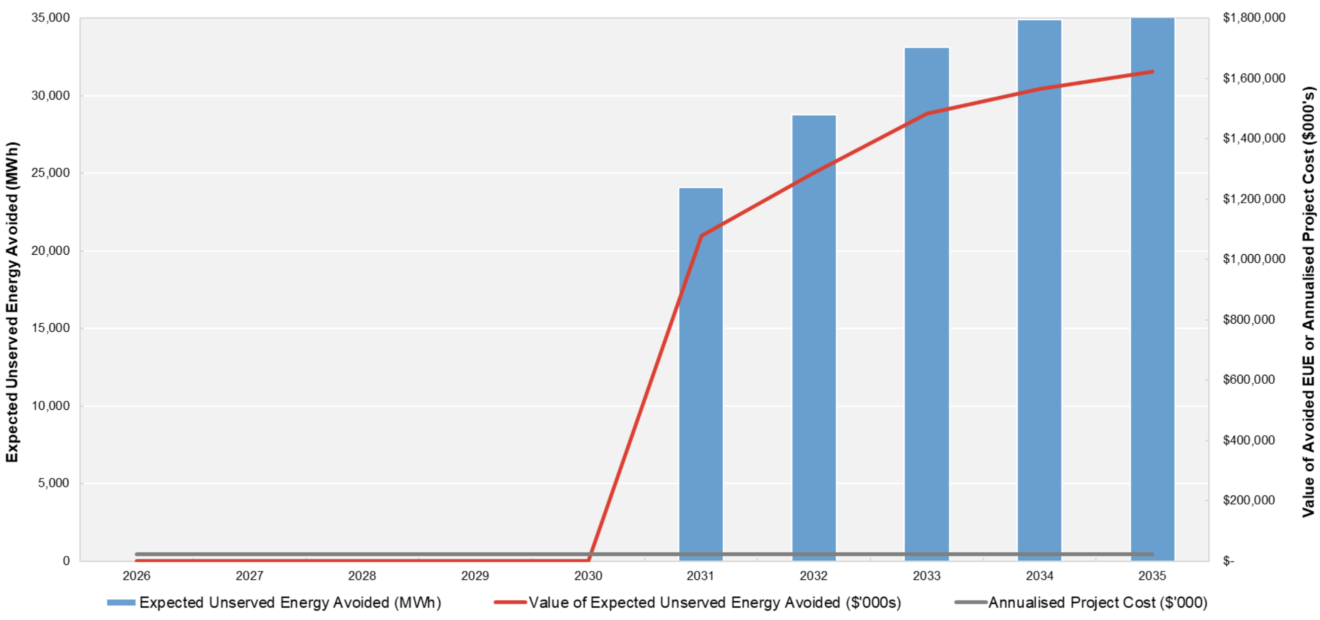
Figure 5-5: SYTS 66 kV simplified single line diagram (Option 5)



The estimated capital cost of this network option is $250 million (real, 2025) and an ongoing operations and maintenance cost of $1.3 million per annum, which has a present value total cost of $199 million and an annualised cost of $22.0 million. Based on this annualised cost, the optimal timing of this option based on the forecast weighted value of EUE at KTS (as set out in Table 2-5) able to be avoided, is before summer 2027-28.

Figure 5-6 identifies the optimal timing of Option 5 based on the avoided EUE risk and its annualised cost.

Figure 5-6: Optimal timing based on avoided risks and annualised costs (Option 5)



However, this option has an estimated construction period of four to five years, therefore this limits the optimum timing to summer 2030-31.

Table 5-5 lists the forecast EUE at KTS with Option 5 in service, based on its optimum timing.

Table 5-5: Forecast EUE at KTS (Option 5)

KTS EUE (MWh pa)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	8.6	1,693	11,804	13,777	-	-	-	-	-
POE50 (N-1)	0.2	187.7	1,881	2,565	2,686	130.4	162.0	195.8	221.6	248.3
POE10 (N)	-	137.8	5,645	25,680	28,801	-	-	-	-	-
POE10 (N-1)	11.2	371.4	2,297	3,057	3,183	149.5	185.0	219.5	245.9	274.4
Total (Weighted[20])	3.5	290	4,885	18,680	21,120	136	169	203	229	256

Table 5-6 lists the forecast value of EUE at KTS with Option 5 in service, based on its optimum timing.

Table 5-6: Forecast value of EUE at KTS (Option 5)

KTS EUE ($m, real 2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	0.16	13.0	218.9	837.0	946.4	6.1	7.6	9.1	10.3	11.5

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

Social licencing risks are considered moderate for this option as even though it only involves work within an existing established substation, the scale of the works is substantial requiring works at 500 kV. The social licensing risks are expected to increase over time as the surrounding area becomes increasingly urbanised. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

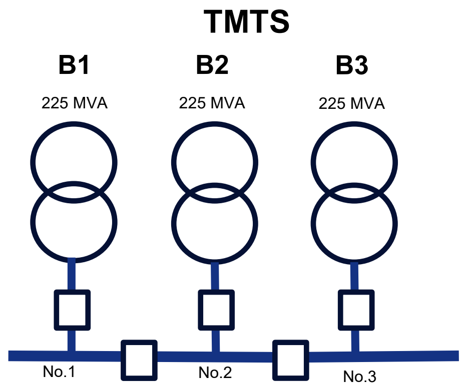
[20] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE

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

This option involves establishing a new Tullamarine (TMTS) terminal station with a new 220 kV and 66 kV switchyard with three new 225 MVA 220/66 kV transformers, to establish new transmission connection assets at this new terminal station. A site is owned by JEN for this proposed new terminal station. Works are also required to augment and connect B1, B2 and B3 into new 220 kV shared transmission assets.

A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 5-7.

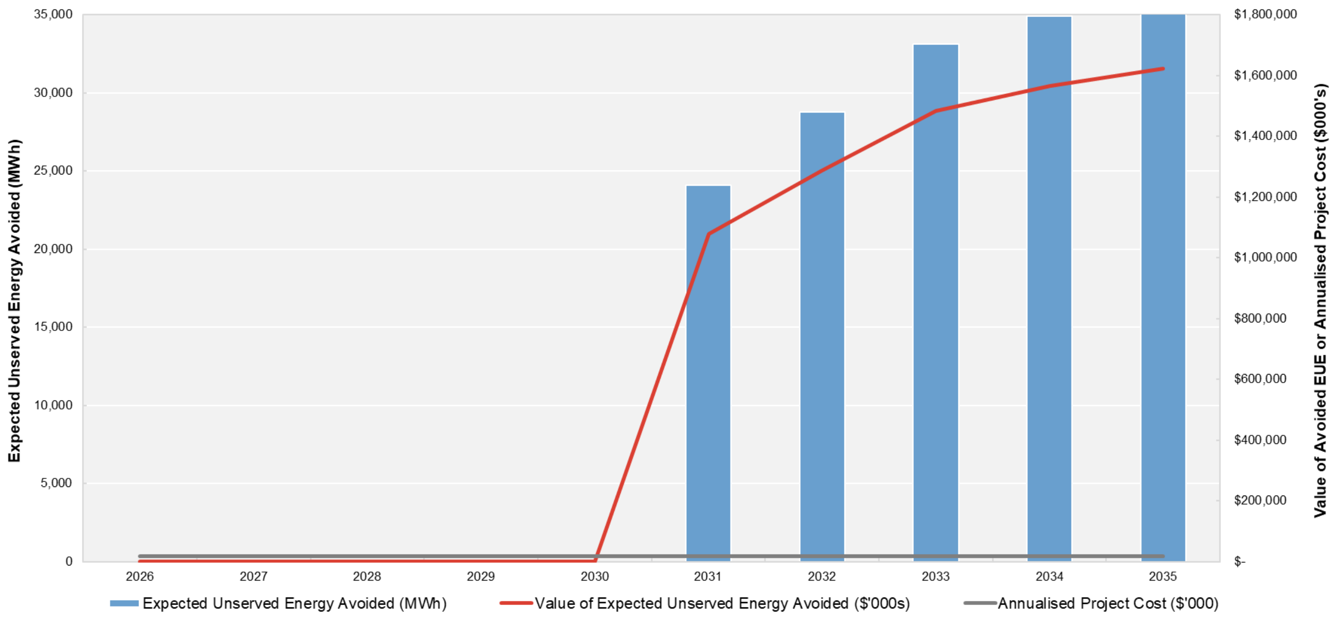
Figure 5-7: TMTS 66 kV simplified single line diagram (Option 6)



The estimated capital cost of this network option is $200 million (real, 2025) and an ongoing operations and maintenance cost of $1.0 million per annum, which has a present value total cost of $151 million and an annualised cost of $16.6 million. Based on this annualised cost, the optimal timing of this option based on the forecast weighted value of EUE at KTS (as set out in Table 2-5) able to be avoided, is before summer 2027-28.

Figure 5-6 identifies the optimal timing of Option 6 based on the avoided EUE risk and its annualised cost.

Figure 5-8: Optimal timing based on avoided risks and annualised costs (Option 6)



However, this option has an estimated construction period of five years, therefore this limits the optimum timing to summer 2030-31.

Table 5-5 lists the forecast EUE at KTS with Option 6 in service, based on its optimum timing.

Table 5-7: Forecast EUE at KTS (Option 6)

KTS EUE (MWh pa)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	8.6	1,693	11,804	13,777	-	-	-	-	-
POE50 (N-1)	0.2	187.7	1,881	2,565	2,686	130.4	162.0	195.8	221.6	248.3
POE10 (N)	-	137.8	5,645	25,680	28,801	-	-	-	-	-
POE10 (N-1)	11.2	371.4	2,297	3,057	3,183	149.5	185.0	219.5	245.9	274.4
Total (Weighted[21])	3.5	290	4,885	18,680	21,120	136	169	203	229	256

Table 5-6 lists the forecast value of EUE at KTS with Option 6 in service, based on its optimum timing.

Table 5-8: Forecast value of EUE at KTS (Option 6)

KTS EUE ($m, real 2025)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	0.16	13.0	218.9	837.0	946.4	6.1	7.6	9.1	10.3	11.5

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

Social licencing risks are considered major for this option. The option involves work to establish a new terminal station, and establishing low profile power lines within existing road reserves and new easements, to connect into the existing distribution network. Only existing transmission line cut-ins through the designated site are required, with no new transmission lines or extensions required. Extensive community consultation and associated building, environmental, cultural heritage and planning permitting will be undertaken as part of this option in the years leading up to the construction works. Pricing for this option is based on a semi-indoor construction to address foreseeable social licence expectations.

[21] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE

6. Assessment approach

This chapter details the assessment approach and assumptions that JEN and Powercor have employed for this RIT-T assessment, as well as the materiality of specific categories of market benefits.

6.1 Assessment method

Consistent with the RIT-T NER requirements[22], cost benefit analysis guidelines[23] and RIT-T application guidelines[24], JEN and Powercor have undertaken a cost-benefit analysis to evaluate and rank the net economic benefits of credible options. All options considered are 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, subject to limitations in the construction lead time.

In planning the network, JEN and Powercor apply a probabilistic planning approach that balances reliability risk with the cost of potential risk mitigation options to identify the credible option that maximises the present value of net economic benefit (the preferred option).

The probabilistic planning approach estimates the service level risk of identified network limitations by combining:

- the impact (consequence) of network limitations under various conditions; and
- the likelihood of those limits being reached, considering the combined probabilities of relevant demand, generation and network availability forecasts eventuating, and the available load transfer capability.

Service level reliability risk is then estimated in monetary terms as the product of:

- expected unserved energy (EUE) driven by the identified capacity limitations, in MWh per annum; and
- the locational value of customer reliability (VCR), in $/MWh.

Having identified the service level reliability risk, JEN and Powercor take into account the estimated 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.

The credible option that maximises the present value of net economic benefit is identified by:

- combining the avoided service level reliability risk of each credible option and that option's implementation and ongoing costs for each year; and
- identifying the credible option with the highest present value of total avoided service level reliability risk less the implementation, and ongoing operating and maintenance costs.

The optimal timing of this preferred option is identified by:

- calculating the preferred option's annualised implementation and ongoing costs; and
- selecting the year when the annual value of the avoided service level risk exceeds this annualised cost.

Application of the probabilistic planning approach often leads to the deferral of action that would otherwise proceed under a deterministic planning standard. Under a probabilistic network planning approach, conditions often exist where some of the load cannot be supplied under rare (but credible) conditions, such as at maximum demand or with a single network element out of service.

[22] Regulatory investment test for transmission, Australian Energy Regulator, 21 November 2024.

[23] Cost Benefit Analysis guideline, Australian Energy Regulator, 21 November 2024.

[24] RIT-T application guideline, Australian Energy Regulator, 21 November 2024.

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;
- network asset reliability (failure rates, repair times); and
- value of customer reliability.

6.2.1 Network asset ratings

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

Table 6-1: KTS thermal capacity ratings (MVA)

KTS Rating	Existing	
	KTS (B1,2,5)	KTS (B3,4)
Summer (N)	509	331
Summer (N-1)	339	331
Winter (N)	509	375
Winter (N-1)	353	375

The existing N-1 rating at KTS (B3,4) is subject to transformer B5 being available (as part of an existing auto-change-over scheme) which is normally supplying KTS (B1,2,5).

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

6.2.2 Forecast maximum demand

The forecast maximum demand (**MD**) at KTS is specified according to its 10 per cent probability of exceedance (**POE10**) and its 50 per cent probability of exceedance (**POE50**) during summer and winter period[25], taking into consideration the major customer data-centre load forecasts.

Table 6-2 provides a summary of the forecast maximum demand for KTS (B1,2,5) during summer and winter (maximum demand) periods. Values in red indicate that the N-1 rating is exceeded. Values in **bold underlined red** indicate that N rating is exceeded.

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

Table 6-2: Forecast maximum demand at KTS (B1,2,5) (MVA)

KTS 66 kV MD	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer POE10	435	576	650	706	706	707	713	718	718	716
Winter POE10	367	513	595	658	664	670	679	685	686	686
Summer POE50	386	527	599	656	655	656	661	666	666	664
Winter POE50	338	484	565	628	633	639	647	654	655	655

KTS (B1,2,5) is expected to exceed its N rating by 2027 for a POE10 summer and winter maximum demand, and POE50 summer maximum demand, and by 2028 for a POE50 winter maximum demand.

Figure 6-1 shows the POE10 and the POE50 forecasts of maximum demand for KTS (B1,2,5) during summer periods relative to its capacity.

Figure 6-1: Summer period maximum demand forecasts for KTS (B1,2,5)

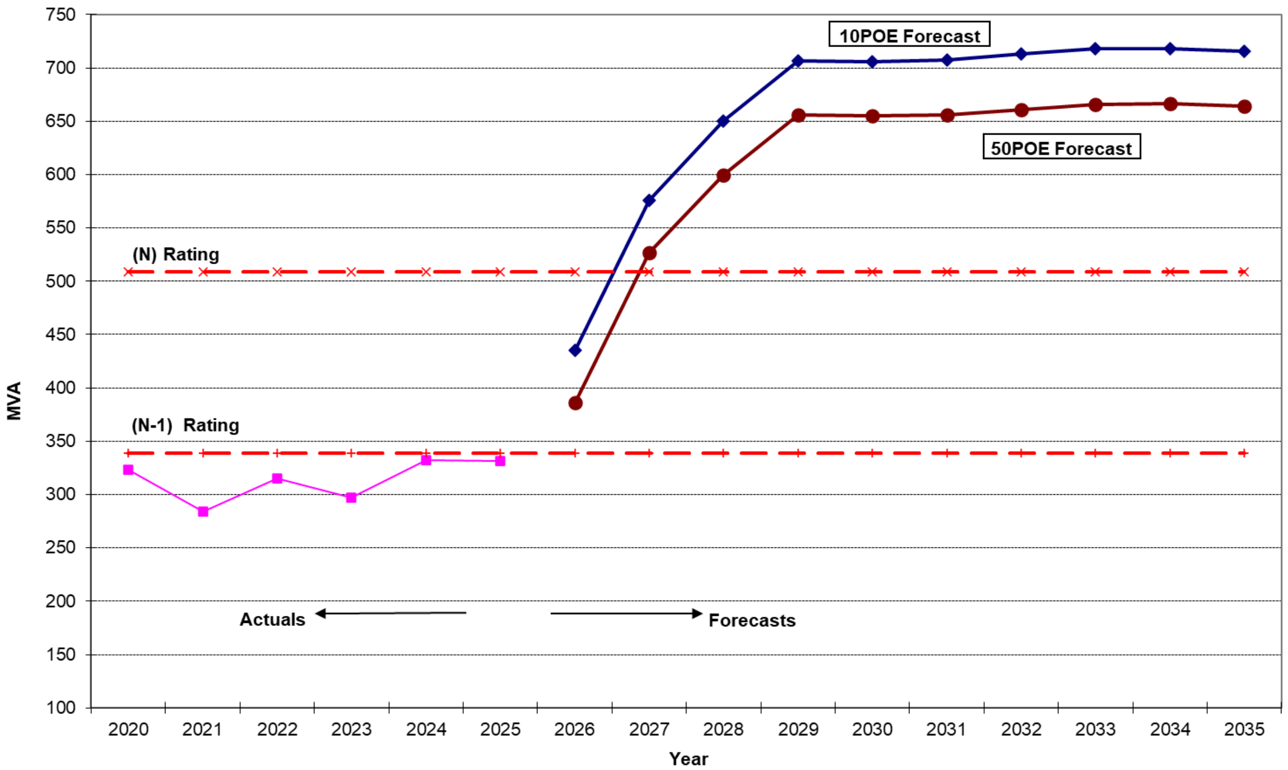


Figure 6-2 shows the POE10 and the POE50 forecasts maximum demand for KTS (B1,2,5) during winter periods relative to its capacity.

Figure 6-2: Winter period maximum demand forecasts for KTS (B1,2,5)

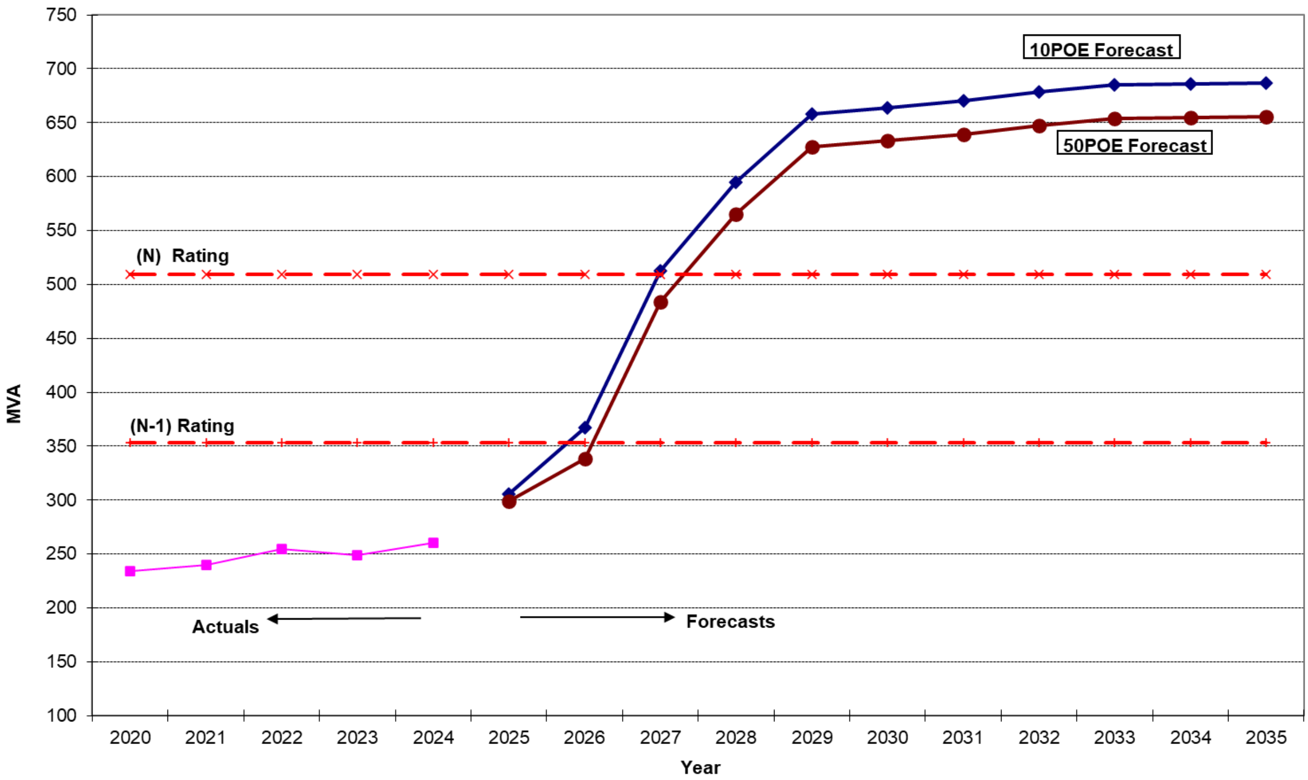


Table 6-3 provides a summary of the forecast maximum demand for KTS (B3,4) during summer and winter (maximum demand) periods. Values in red indicate that the N-1 rating is exceeded. Values in **bold underlined red** indicate that N rating is exceeded.

Table 6-3: Forecast maximum demand at KTS (B3,4) (MVA)

KTS 66 kV MD	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer POE10	267	**349**	**430**	**433**	**434**	**437**	**442**	**447**	**450**	**453**
Winter POE10	237	323	**410**	**418**	**425**	**432**	**441**	**448**	**453**	**458**
Summer POE50	243	324	**406**	**408**	**410**	**413**	**418**	**423**	**425**	**427**
Winter POE50	235	321	**408**	**416**	**423**	**430**	**438**	**446**	**451**	**456**

KTS (B3,4) is expected to exceed its N and N-1 rating by 2027 for a POE10 summer maximum demand, and by 2028 for a POE10 and POE50 summer and winter maximum demand.

Figure 6-3 shows the POE10 and the POE50 forecasts of maximum demand for KTS (B3,4) during summer periods relative to its capacity.

Figure 6-3: Summer period maximum demand forecasts for KTS (B3,4)

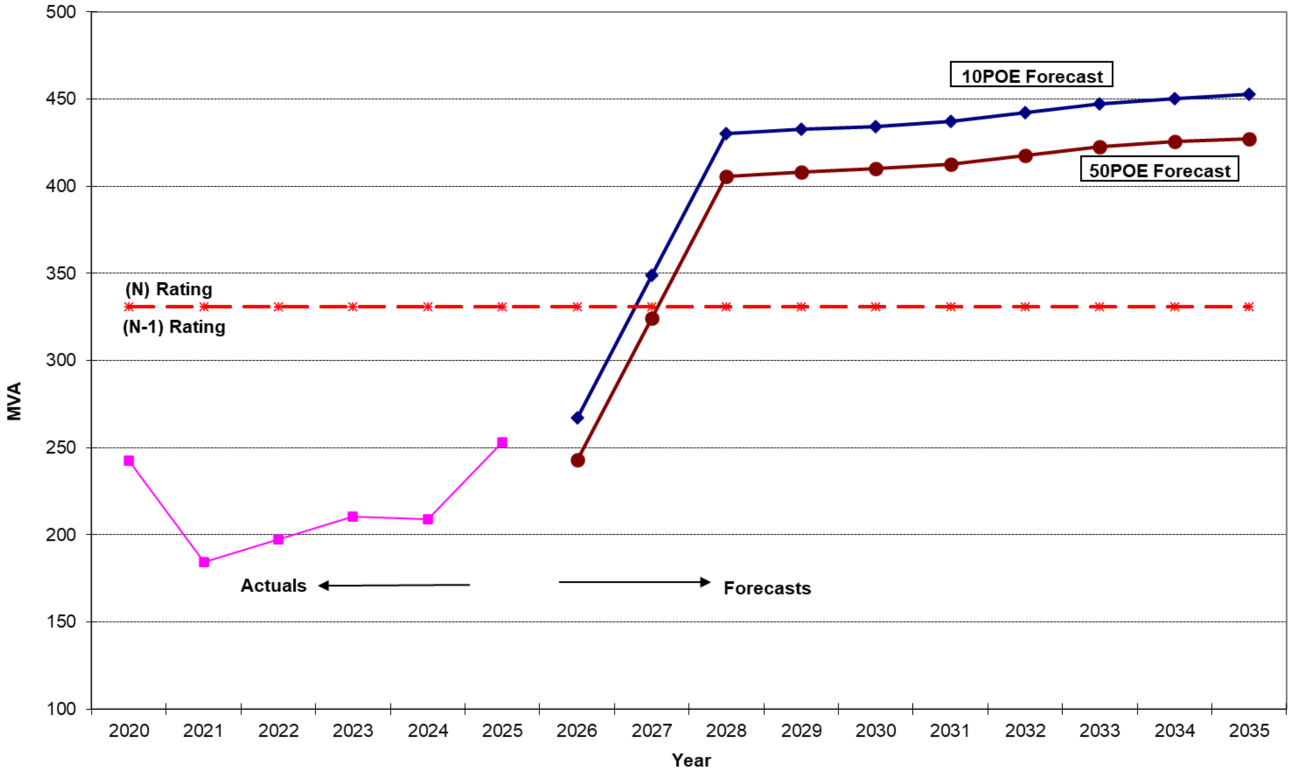
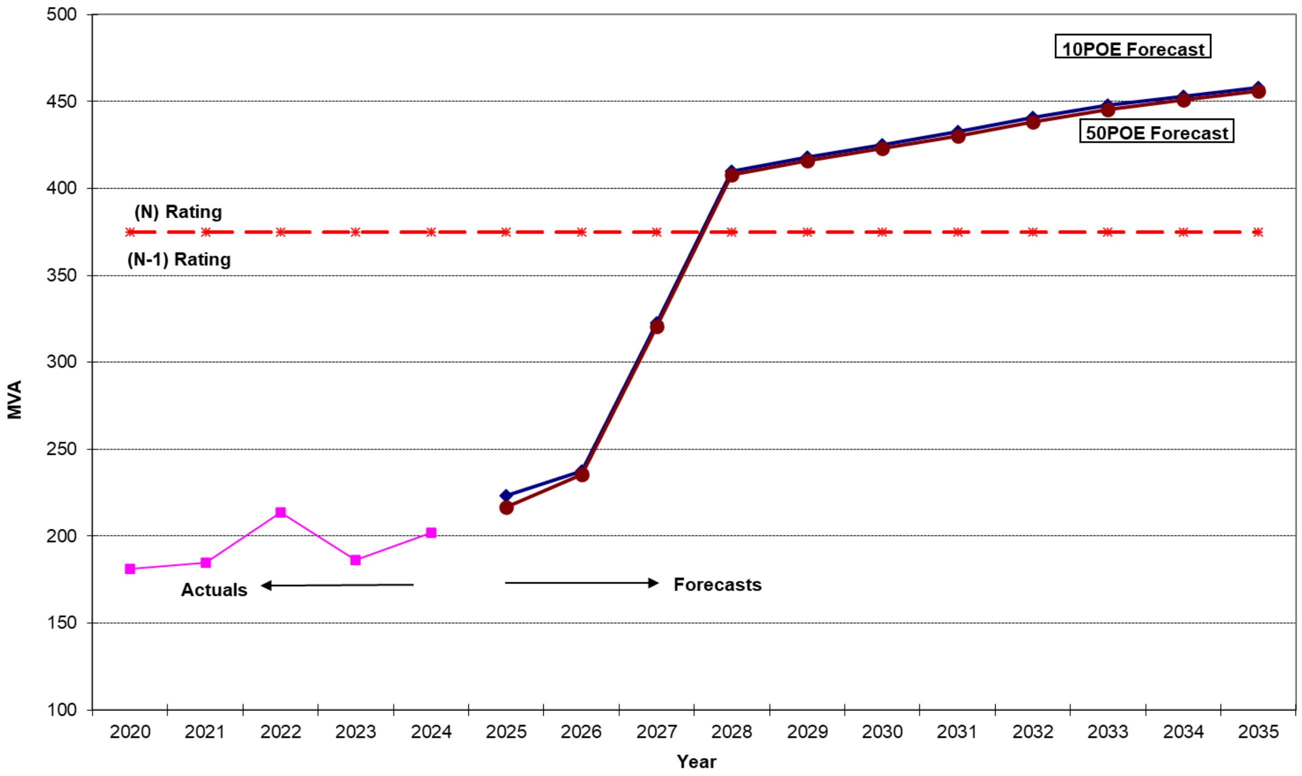


Figure 6-4 shows the POE10 and the POE50 forecasts maximum demand for KTS (B3,4) during winter periods relative to its capacity.

Figure 6-4: Winter period maximum demand forecasts for KTS (B3,4)



6.2.3 Load transfer capability

There is the capacity to transfer 35 MVA of load at KTS to other terminal stations (post-contingent) via the distribution feeder network, with 20.0 MVA from KTS (B1,2,5) and 15.0 MVA from KTS (B3,4). This is expected to be maintained over the 10-year planning horizon.

6.2.4 Annual load profile

The load-duration curves for KTS are shown in Figure 6-5 and Figure 6-6 at times of peak demand periods in winter and summer seasons.

Figure 6-5: Load-duration profile for KTS (B1,2,5) at peak demand

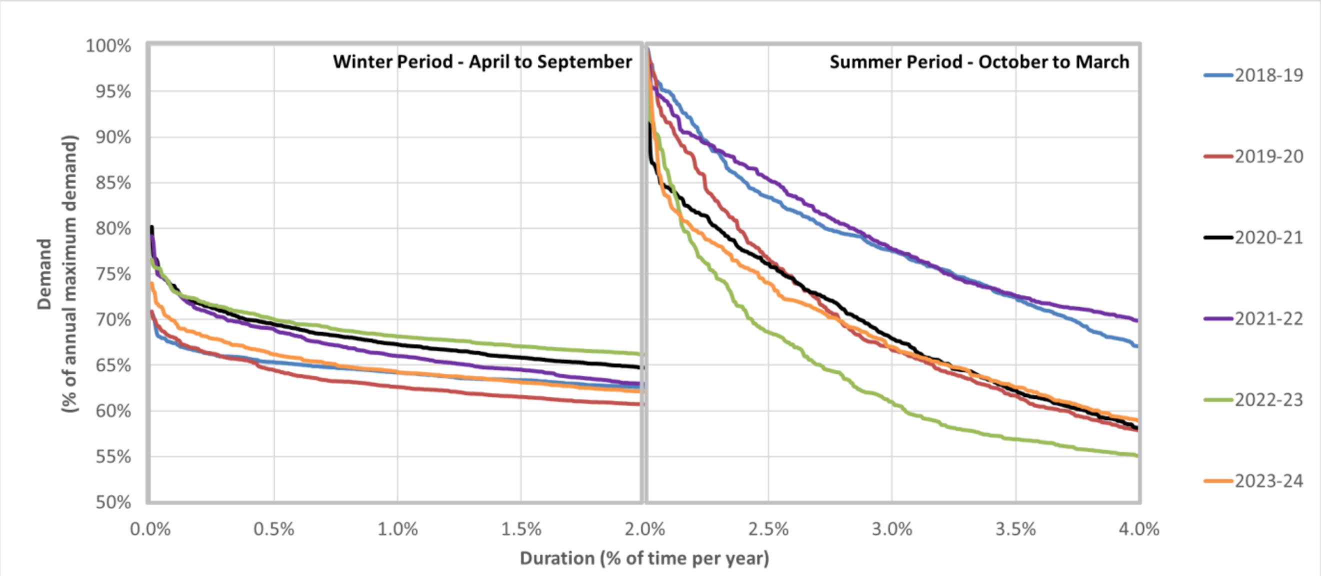
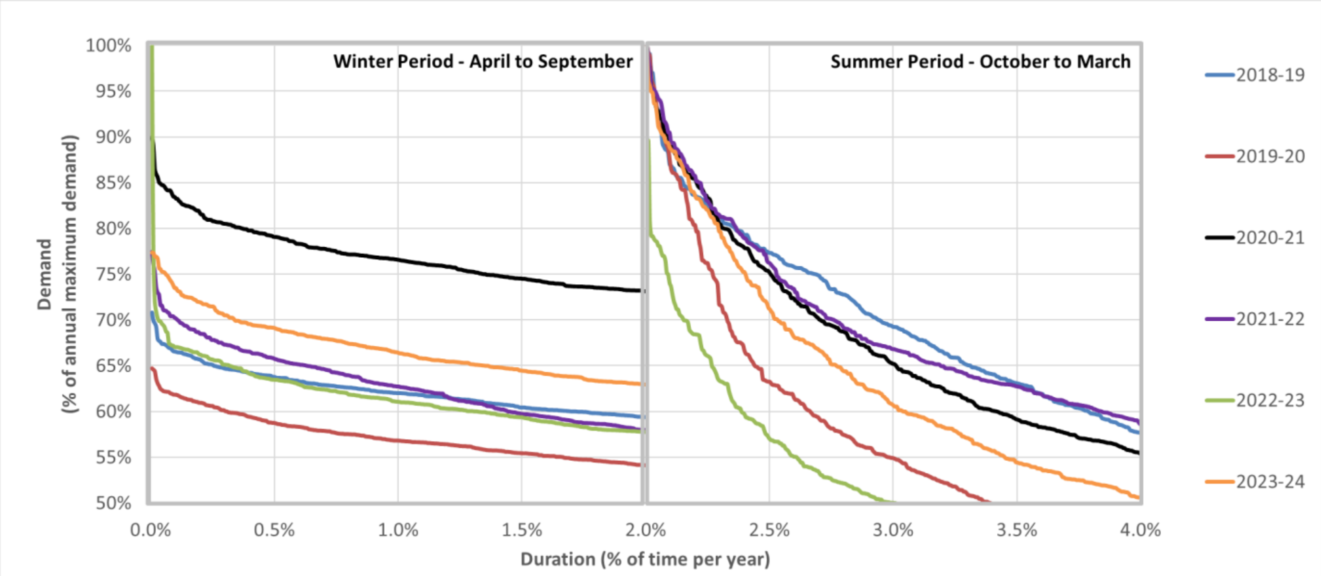


Figure 6-6: Load-duration profile for KTS (B3,4) at peak demand



The shape of the curves are strongly influenced by the coincidence of extreme ambient temperature on working weekdays and the number of times this occurs in any one year. This is illustrated in Figure 6-7 and Figure 6-8 for the full year.

Figure 6-7: Annual load-duration profile for KTS (B1,2,5)

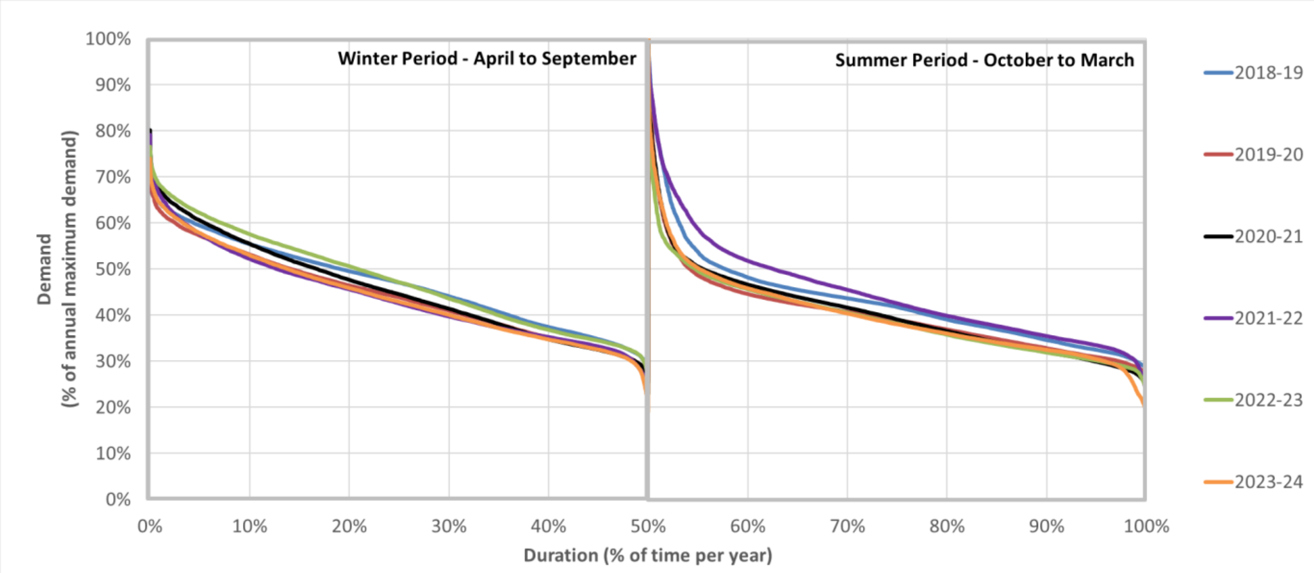
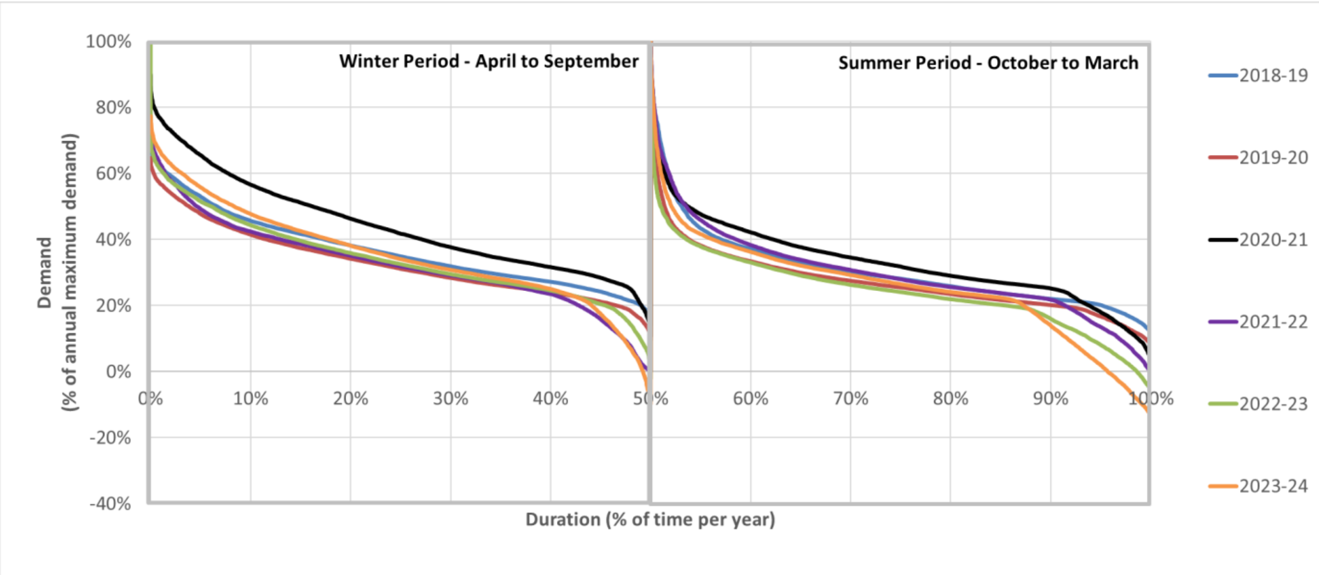


Figure 6-8: Annual load-duration profile for KTS (B3,4)



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

A total of 229 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to KTS. It consists of:

- 203 MW of solar PV systems that are smaller than 1 MW, which includes 102 MW in the Powercor distribution system and 111 MW in the JEN distribution system; and
- 26 MW capacity of embedded generators greater than 1 MW, which includes 5 MW in the Powercor distribution system and 21 MW in the JEN distribution system.

The typical net daily load profiles at KTS during the summer season are shown in Figure 6-9 and Figure 6-10.

Figure 6-9: Daily load profile for KTS (B1,2,5) (summer peak demand)

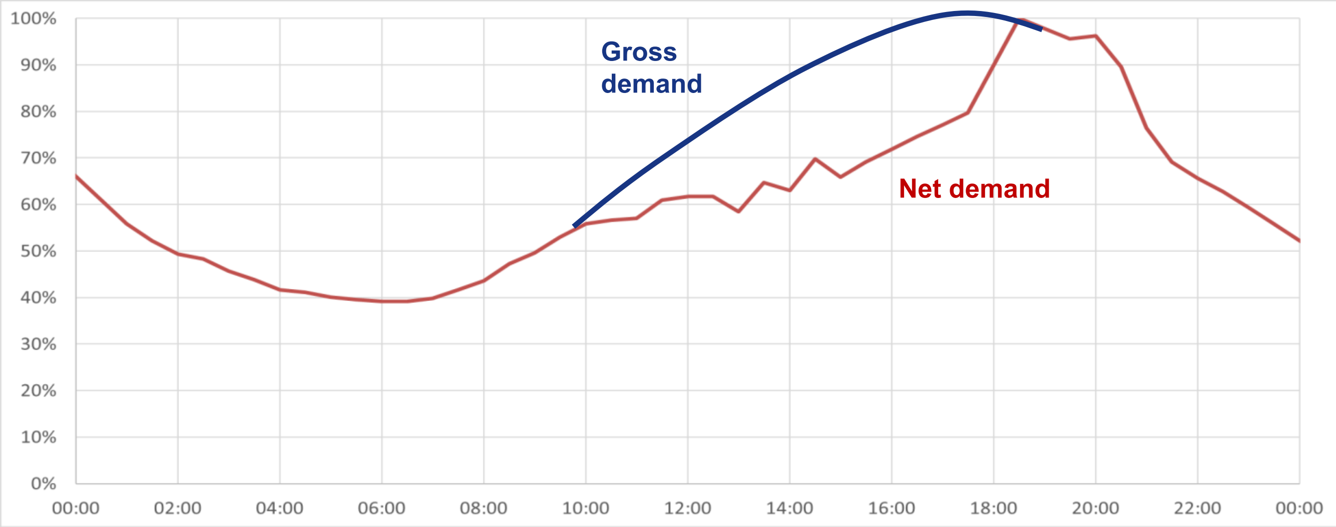
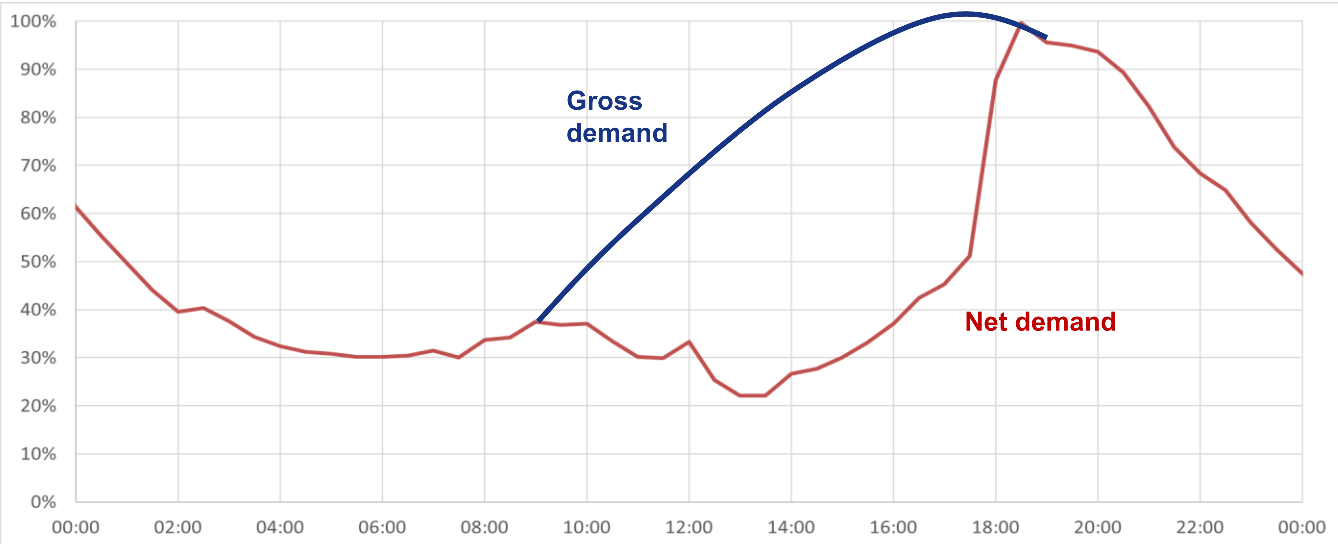


Figure 6-10: Daily load profile for KTS (B3,4) (summer peak demand)



6.2.5 Network asset reliability

Table 6-4 provides a summary of the KTS 220/66 kV transformer reliability information used in the EUE analysis.

Table 6-4: KTS 66 kV transformer reliability information

Transformer Reliability Quantity	Value	Description
Major forced outage rate (failure rate)	1.0% per annum	A major outage is expected to occur once per 100 transformer-years. In a population of 100 terminal station transformers, expect one major failure of any one transformer per year.
Weighted average of major outage duration (repair time)	2.65 months	On average, 2.65 months is required to return the transformer to service, during which time the transformer is not available for service.
Expected transformer unavailability due to a major outage per transformer-year	0.22%	On average, each transformer would be expected to be unavailable due to major outages for 0.01 x 2.65/12 = 0.22% of the time, or 19 hours per year.

6.2.6 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.

JEN and Powercor have applied locational VCR values based on the estimates in the Australian Energy Regulator's (**AER**) Values of Customer Reliability Review published in December 2024[26]. 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 following VCRs for KTS (presented in Table 6-5 and Table 6-6), with the aggregated value for KTS being $44,811 per MWh.

Table 6-5: KTS (B1,2,5) value of customer reliability

Sector	AER VCR ($/MWh, 2024)	Energy consumption	Weighted VCR ($/MWh)
Residential Suburban	55,100	37.1%	20,464
Residential Regional	38,900	0.0%	0
Agricultural	22,250	0.0%	0
Commercial	34,390	45.5%	15,634
Large Business[27]	33,100	5.0%	1,645
Industrial	33,490	12.4%	4,163
Composite		**100%**	**41,906**

Table 6-6: KTS (B3,4) value of customer reliability

Sector	AER VCR ($/MWh, 2024)	Energy consumption	Weighted VCR ($/MWh)
Residential Suburban	55,100	64.7%	35,666
Residential Regional	38,900	0.0%	0
Agricultural	22,250	0.3%	67
Commercial	34,390	30.2%	10,369
Large Business[27]	33,100	0.0%	0
Industrial	33,490	4.8%	1,614
Composite		**100%**	**47,716**

6.3 Assessment parameters

The key parameters used in this RIT-T for the cost-benefit assessment include:

- assessment period;
- discount rate; and
- option cost estimations.

[26] AER 2024 published VCRs. Climate zone 6 applies at KTS.

[27] Greater than 10 MW.

6.3.1 Assessment period

For this RIT-T we have undertaken the NPV analysis over a ten-year period, from 2026 to 2035. We consider that the length of this assessment period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. The assessment period accounts for the expected demand growth in the supply area intended to be addressed by the credible options in this RIT-T. The relatively short time period proposed to be used for the assessment reflects the possibility that the current options only address the immediate need (due to the uncertainty of the demand forecasts) and that a further augmentation of KTS may be needed in future when the major customer data-centre load actually materialises, in which case another RIT-T will be initiated.

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

6.3.2 Discount rate

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

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

6.3.3 Approach to cost estimation for network options

The costs for each option have been calculated by AusNet Transmission Group, JEN 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 RIT-T are fully loaded including escalations, overheads, financing charges and management reserve (contingency risk). All cost estimates are escalated to real 2025 dollars based on the information available at the time of preparing this report. Overheads and financing charges comprise approximately 10.7% of the total costs, and contingency risk of 5.8%.

Social license costs have been included as they are expected to be material for option 4, 5 and 6 only. The importance of allocating appropriate costs to social licence activities is supported by established best practice in regulated electricity infrastructure delivery, as articulated in Powercor's Commitment on Engagement and Land Access document[29]. The document clearly recognises that effective, genuine stakeholder engagement is fundamental to gaining and maintaining a social licence to operate, particularly 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 1 per cent of the capital cost per annum for brownfield sites and 0.5 per cent for greenfield sites.

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

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

[29] "Powercor commitment on engagement and land access", Powercor Australia.

6.4 Materiality of market benefits

6.4.1 Material classes of market benefits

NER clause 5.15A.2(b)(4) sets out the classes of market benefits that must be considered in a RIT-T. JEN and Powercor estimate that the market benefits that are likely to be material are:

- **Changes in involuntary load shedding** – the proposed approach to calculate the benefits is therefore in reducing the level of EUE as set out in section 6.1, that is the avoided risk of deteriorating reliability from involuntary load shedding, taking into account changes in load transfer capability.

We consider that changes in avoided EUE is the only class of market benefit that is material to the RIT-T assessment.

6.4.2 Market benefits not considered material

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

- **Changes in fuel consumption arising through different patterns of generation dispatch** – as the network is not normally interconnected to the extent that asset failures cannot be remediated by re-dispatch of generation, and the wholesale market impact is expected to be the same.

- **Changes in voluntary load curtailment** – no non-network proposals were submitted during the consultation on the PSCR, therefore this is not considered to be a material market benefit.

- **Changes in costs for parties, other than the RIT-T proponent** – there is no other known investment, either generation or transmission, that will be affected by any option considered.

- **Differences in the timing of expenditure** – the timing of other unrelated expenditure is not expected to be impacted by the options considered in this assessment. 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.

- **Change in network losses** – 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.

- **Changes in ancillary services costs** – the options are not expected to impact on the demand for and supply of ancillary services.

- **Changes in Australia's greenhouse gas emissions** – changes in greenhouse gas emissions from changes in network losses, 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.

- **Competition** benefits – there is no competing generation affected by the limitations and risks being addressed by the options considered for this RIT-T.

- **Option value** – this is likely to arise where there is uncertainty regarding future outcomes or in the information that is currently available, and the credible options are sufficiently flexible to respond to change. 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.

6.5 Sensitivity studies

The robustness of the investment decision is tested using the range of input assumptions described in Table 6-7. This analysis varies the assumptions used for the base case as detailed in section 6.2

Table 6-7: 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	90% of base case maximum demand	100% of base case maximum demand	105% of base case maximum demand
Asset failure rate	80% of base	100% of base	120% of base
Value of customer reliability	80% of AER VCRs - site specific for KTS	100% of AER VCRs - site specific for KTS	120% of AER VCRs - site specific for KTS
Discount rate	4.69% - regulatory discount rate	7.00% - commercial discount rate (IASR)	10.00% (IASR)
Asset life	20 years	45 years	60 years

6.6 Scenario modelling to address uncertainty

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

The assessment for this PADR was conducted under three future-state scenarios by choosing the parameters in Table 6-7 with high uncertainty, as follows:

- **Central scenario** – adopting the base case assumptions in Table 6-7;
- **Low scenario** – adopting lower bound demand, failure rates and VCR; and
- **High scenario** – adopting higher bound demand, failure rates and VCR.

These are plausible scenarios which reflect different assumptions about the future energy landscape and other factors that are expected to affect the relative market benefits of the options considered. In Table 6–8, 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 6-8: 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 decade there was significant uncertainty in forecasting maximum demand. Factors including economic growth, retail electricity prices, gas electrification, and uptake of distributed energy resources (including rooftop solar, batteries and electric vehicles) have contributed to the uncertainty. Uncertainty is expected to remain high over the planning horizon in each of these areas. An equal weighting has been applied to high and low scenarios and a higher weighting has been applied to the central scenario as we only have committed block load customers included in the forecast demand.
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.

6.7 RIT-T reopening triggers

If it is identified that the cost of the preferred option exceeds the cost threshold of $103 million for RIT-T reopening triggers, JEN and Powercor propose the following triggers that would necessitate the need to reopen the RIT-T for this identified need:

- 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
- an increase in the cost of the preferred option by more than 30%; or
- a non-preferred network credible option present value real cost decrease of 25% or more; or
- the preferred option is unable to be delivered for any reason, to address the identified need.

7. Options assessment

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

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 7-1 based on their optimal timing.

Table 7-1: Calculated present value of gross benefits relative to base case ($ million, real 2025)

Option	Low Scenario	Central Scenario	High Scenario
1	0.0	0.0	0.0
3	587	4,928	11,395
4	605	4,061	9,065
5	605	4,061	9,065
6	605	4,061	9,065

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 7-2 based on their based on their optimal timing.

Table 7-2: Calculated present value of capital and operating costs relative to base case ($ million, real 2025)

Option	Low Scenario	Central Scenario	High Scenario
1	(0.0)	(0.0)	(0.0)
3	(83.3)	(83.3)	(83.3)
4	(228.9)	(228.9)	(228.9)
5	(199.2)	(199.2)	(199.2)
6	(150.5)	(150.5)	(150.5)

7.3 Present value of net economic benefits

The estimated present value of net economic benefits of each option relative to the “Do Nothing” base case, being the present value of gross benefits minus the present value of capital and operating costs, is presented in Table 7-3 based on their optimal timing.

Table 7-3: Calculated present value of net economic benefits relative to base case ($ million, real 2025)

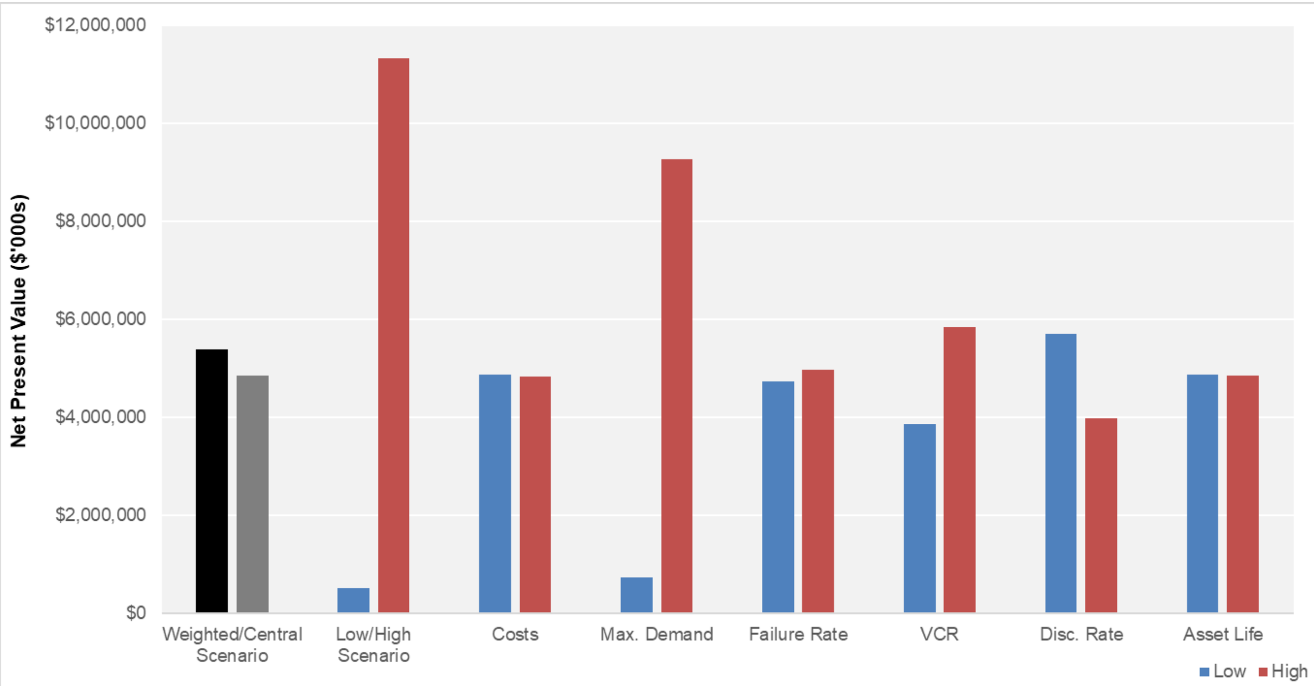
Option	Low Scenario	Central Scenario	High Scenario	Weighted Scenario	Ranking
	25%	50%	25%	100%	
1	0	0	0	0	5
3	504	4,845	11,312	5,377	1
4	376	3,832	8,836	4,218	4
5	405	3,862	8,866	4,248	3
6	454	3,910	8,914	4,297	2

7.4 Proposed preferred option

Given Option 3 maximises the present value of net economic benefits under the weighted scenario and that net benefit remains positive under all credible scenarios, we recommend Option 3 as the proposed preferred option with an optimum timing being 2028-29. Option 3 satisfies the requirements of the RIT-T.

The robustness of the proposed preferred option's net economic benefits to credible variations in key parameters (in Table 6–7), is demonstrated in the sensitivity study results of Figure 7–1. Under all credible sensitivities, the net present value of benefits remains positive for Option 3.

Figure 7-1: NPV sensitivity analysis of the preferred option ($ thousand, real 2025)



7.5 Optimal timing of the proposed preferred option

This section identifies and tests the robustness of the optimal timing of Option 3 for different assumptions of key parameters as detailed in Table 6-7. The changes in timing away from the optimal timing of 2028-29 for each of the sensitivities is presented in Table 7-4.

Table 7-4: 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
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 timing of the proposed preferred option is robust, remaining unchanged in all sensitivities.

8. Draft conclusion and next steps

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

8.1 Draft conclusion

The cost-benefit economic evaluation assessment undertaken for this PADR has concluded that the proposed preferred option to address the identified need for this RIT-T is Option 3. It is the proposed preferred option in accordance with NER clause 5.16.1(b) because it is the credible option that maximises the net present value of the net economic benefit. It therefore satisfies the RIT-T. The proposed preferred option is found to have positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver $5,377 million in present value net economic benefits over the analysis period.

This option involves upgrading all three transformers at KTS (B1,2,5), and installing a new third transformer at KTS (B3,4) to increase the thermal capacity of the KTS transmission connection assets to address the identified need. There is provision to accommodate these transformers at KTS. The estimated capital cost of this option is $91 million (real, 2025) with annual operating and maintenance costs relating to this investment of approximately $0.9 million, with an optimum timing of 2028-29. This timing is achievable based the construction lead time required for this option.

8.2 Next steps

JEN and Powercor invite written submissions and enquiries on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "**Keilor Terminal Station Capacity Constraint RIT-T**" and directed to both:

Aaron Abbruzzese (JEN)

Data Centre Planning and Delivery Team Leader

PlanningRequest@jemena.com.au

and

Richard Robson (Powercor)

Manager Sub-transmission Planning and Major Connections

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The consultation on this PADR is open for 6 weeks. Submissions are due on or before 12 June 2026. Submissions will be published on the Australian Energy Market Operator (AEMO), JEN 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.

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

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

Publication of that report conclude consultation on this RIT-T.

JEN and Powercor intend on publishing the PACR by end 2026.

9. Appendix A – RIT-T compliance checklist

This appendix sets out a checklist in Table 9-1 which demonstrates the compliance of this PADR with the requirements of clause 5.16.4(k) of the NER, version 243.

Table 9-1: PADR RIT-T compliance checklist

A RIT-T proponent must prepare a report which must include:	Chapter
(1) a description of each credible option assessed;	Chapter 3
(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Chapter 4
(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	Chapter 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 proposed preferred option;	Chapter 7
(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i)details of the technical characteristics; (ii)the estimated construction timetable and commissioning date; (iii)if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv)a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission;	Chapter 8
(10) if each of the following apply to the RIT-T project: (i)the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and (ii)AEMO is not the sole RIT-T proponent, the RIT reopening triggers applying to the RIT-T project;	Chapter 6