Keilor Terminal Station Capacity Constraint

RIT-T Stage 1: Project Specification Consultation Report (PSCR)

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 specification consultation report (**PSCR**) is the first 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]. This report contains information to enable prospective non-network and standalone power system (**SAPS**) providers to propose alternative options, including demand-side response or embedded generation and storage solutions.

Identified Need

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

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.

In forecasting future demand at KTS, JEN and Powercor have moderated the forecast demands provided by the prospective major customer data-centres in the supply area, to take into account the likelihood of their connection proceeding and their progress through the network connection process. The different moderating factors applied address the uncertainty of the connections by variously deferring the connection date, slowing the uptake of the forecast load, and reducing the magnitude of the estimated connecting load.

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 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 2024 Transmission Connection Planning Report (**TCPR**), published jointly by the Victorian DNSPs[3].

[1] National Electricity Rules, version 225, Australian Energy Market Commission (AEMC), 2025.

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

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

Potential credible options

The potential credible options considered in this PSCR 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 66 kV buses and two new transformers;
- Option 5 - Establish a new 500/220/66 kV switchyard at Sydenham Terminal Station (SYTS);
- Option 6 - Establish a new 220/66 kV terminal station.

Initial analysis by JEN and Powercor has identified that Option 3 is likely to be the preferred network option, as it provides the greatest net market benefit. This assessment will be confirmed through this RIT-T process.

Submissions

JEN and Powercor invite written submissions and enquiries on the matters set out in this PSCR 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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The consultation on this PSCR is open for 12 weeks. Submissions are due on or before 5 September 2025. 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 PSCR consultation period, JEN and Powercor will, having regard to any submissions received on the PSCR, prepare and publish a project assessment draft report (**PADR**) including:

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

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

JEN and Powercor intend on publishing the PADR by the Fourth quarter of 2025.

Table of contents

List of tables

List of figures

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 over 370,000 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
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 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 the identified need. The purpose of the RIT-T is to identify the credible option that maximises the present value of net economic benefit (the preferred option). The process follows the requirements in clauses 5.15A and 5.16 of the National Electricity Rules (**NER**)[4].

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[5]. 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 Tullamarine 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 Keilor Terminal Station (**KTS**). 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.

This project specification consultation report (**PSCR**) is the first stage of the **Keilor Terminal Station Capacity Constraint RIT-T** consultation process and has been jointly prepared by JEN (as the lead proponent) and Powercor in accordance with section 4.2 of the RIT-T Application Guidelines[6], to enable prospective non-network and standalone power system (**SAPS**) providers to propose alternative credible options, including demand-side response or embedded generation and storage solutions.

The structure of this PSCR 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** outlines the assumptions made in identifying the need;
- **Chapter 4** outlines the proposed assessment methodology for this RIT-T;
- **Chapter 5** outlines the technical characteristics that a non-network or SAPS option would be required to deliver to address the identified need;
- **Chapter 6** describes the options that JEN and Powercor consider could potentially address the identified need;
- **Chapter 7** invites interested stakeholders to make a formal written submission on this PSCR.

The need for investment has been foreshadowed in the 2024 Transmission Connection Planning Report (**TCPR**)[7], published jointly by the Victorian DNSPs.

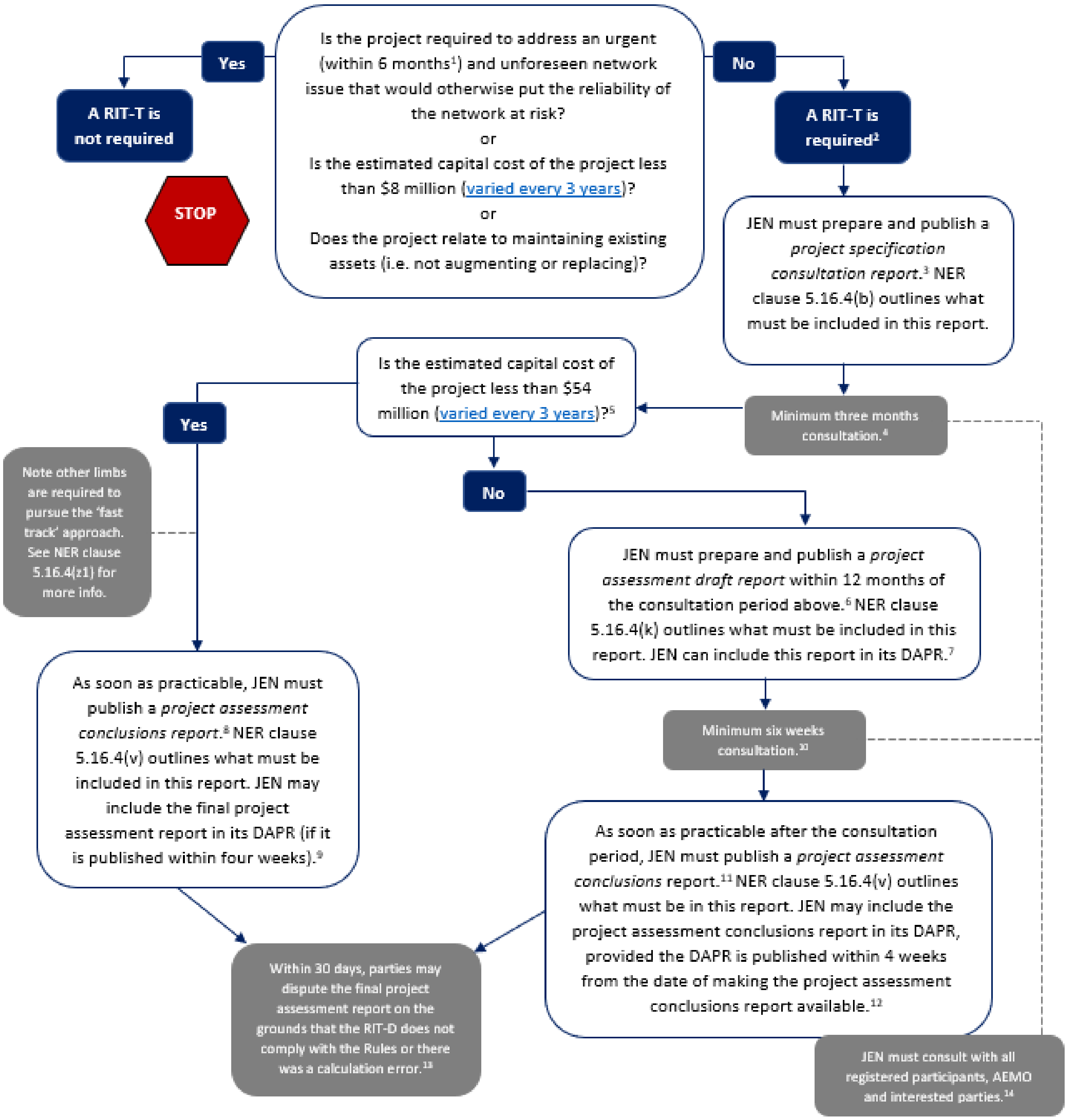
[4] National Electricity Rules, version 225, Australian Energy Market Commission (AEMC), 2025

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

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

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

Figure 1-1: RIT-T process flow chart



1 NER, cl. 5.16.3(b).
2 NER, cl. 5.15A.1(b).
3 NER, cl. 5. 5.16.4(b).
4 NER, cl. 5.16.4(g).
5 NER, cl. 5.16.4(z1).
6 NER, cl. 5.16.4(j).
7 NER, cl. 5.16.4(n).
8 NER, cl. 5.16.4(u)(1).
9 NER, cl. 5.16.4(z).
10 NER, cl. 5.16.4(r).
11 NER, cl. 5.16.4(t).
12 NER, cl. 5.16.4(z).
13 NER, cl. 5.16B(c).
14 NER, cl. 5.16.4(a).

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

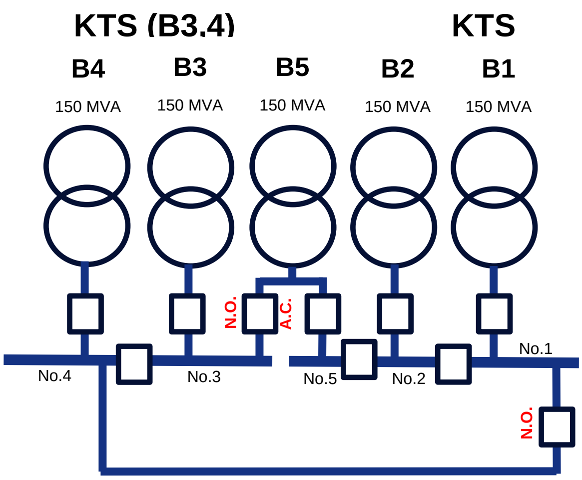
KTS is located in the north-west of Greater Melbourne. It operates at 220/66 kV and supplies major geographic centres such as Sunbury, Sydenham, Tullamarine, Airport West, St. Albans, Woodend, Gisborne, Pascoe Vale, Essendon, Keilor, Sunshine and Braybrook.

Electricity demand at KTS is soon expected to be one of the fastest growing in Victoria, with more than nine recent 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,[8] 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: KTS 66 kV simplified single line diagram (existing)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 (as described above). Hence the available capacity across these two bus groups is intricately linked.

[8] 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 currently account for 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.

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 3.2.2 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.

Given the uncertainty that many of these uncommitted connections have in terms of commitment, timing and load uptake, we have not included their raw aggregated maximum demand within our underlying demand forecast. Instead, we have moderated their forecast maximum demands into aggregated block load forecasts. In doing so, we have applied several moderating factors to account for uncertainty - i.e., deferring the assumed connection date, slowing the uptake of the forecast data centre load, and reducing the magnitude of the estimated connecting load, relative to the forecasts provided by the proponents.

JEN and Powercor intend to further test the uncertainty of future loads in the NPV assessment presented in the project assessment draft report (**PADR**) through the adoption of scenarios reflecting differing demand forecasts.

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. If action is not taken, 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. 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 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), taking into account the moderated 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>2025</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></tr>
<tr><td colspan="11">Load at risk above ‘N’ (MVA)</td></tr>
<tr><td>Summer POE10</td><td>0</td><td>0</td><td>0</td><td>74</td><td>139</td><td>186</td><td>225</td><td>262</td><td>282</td><td>301</td></tr>
<tr><td>Winter POE10</td><td>0</td><td>0</td><td>0</td><td>0</td><td>43</td><td>86</td><td>120</td><td>151</td><td>170</td><td>188</td></tr>
<tr><td>Summer POE50</td><td>0</td><td>0</td><td>0</td><td>47</td><td>112</td><td>159</td><td>197</td><td>234</td><td>254</td><td>272</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>0</td><td>0</td><td>0</td><td>30</td><td>73</td><td>106</td><td>138</td><td>156</td><td>173</td></tr>
<tr><td colspan="11">Time at risk above ‘N’ (h pa)</td></tr>
<tr><td>Summer POE10</td><td>0</td><td>0</td><td>0</td><td>4</td><td>23</td><td>50</td><td>78</td><td>101</td><td>120</td><td>145</td></tr>
<tr><td>Winter POE10</td><td>0</td><td>0</td><td>0</td><td>0</td><td>25</td><td>145</td><td>335</td><td>560</td><td>690</td><td>840</td></tr>
<tr><td>Summer POE50</td><td>0</td><td>0</td><td>0</td><td>4</td><td>10</td><td>36</td><td>56</td><td>81</td><td>100</td><td>117</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>0</td><td>0</td><td>0</td><td>10</td><td>99</td><td>252</td><td>460</td><td>594</td><td>725</td></tr>
<tr><td colspan="11">Load at risk above ‘N-1’ (MVA)</td></tr>
<tr><td>Summer POE10</td><td>28</td><td>85</td><td>157</td><td colspan="7">170</td></tr>
<tr><td>Winter POE10</td><td>0</td><td>0</td><td>61</td><td>139</td><td colspan="6">176</td></tr>
<tr><td>Summer POE50</td><td>0</td><td>59</td><td>131</td><td colspan="7">170</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>0</td><td>49</td><td>127</td><td colspan="6">176</td></tr>
<tr><td colspan="11">Time at risk above ‘N-1’ (h pa)</td></tr>
<tr><td>Summer POE10</td><td>3</td><td>18</td><td>85</td><td>222</td><td>514</td><td>833</td><td>1066</td><td>1365</td><td>1576</td><td>1766</td></tr>
<tr><td>Winter POE10</td><td>0</td><td>0</td><td>154</td><td>946</td><td>1650</td><td>2155</td><td>2507</td><td>2836</td><td>3025</td><td>3202</td></tr>
<tr><td>Summer POE50</td><td>1</td><td>5</td><td>56</td><td>161</td><td>376</td><td>521</td><td>836</td><td>1173</td><td>1342</td><td>1494</td></tr>
<tr><td>Winter POE50</td><td>0</td><td>0</td><td>93</td><td>812</td><td>1497</td><td>2010</td><td>2375</td><td>2690</td><td>2885</td><td>3064</td></tr>
<tr><td colspan="11">Weighted EUE[9]</td></tr>
<tr><td>‘N’ EUE (MWh)</td><td>0.0</td><td>0.0</td><td>0.0</td><td>94.4</td><td>601</td><td>3,688</td><td>10,768</td><td>22,929</td><td>32,740</td><td>44,252</td></tr>
<tr><td>‘N-1’ EUE (MWh)</td><td>0.0</td><td>0.6</td><td>10.4</td><td>167</td><td>527</td><td>919</td><td>1,290</td><td>1,677</td><td>1,910</td><td>2,143</td></tr>
</table>

[9] 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.

Total EUE[10] (MWh)	0.0	0.6	10.4	261	1,128	4,607	12,058	24,606	34,650	46,395
Value of EUE ($m[11])	**0.00**	**0.03**	**0.43**	**11.0**	**47.3**	**193**	**505**	**1,031**	**1,452**	**1,944**

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 3.2.6.

The EUE is estimated to have a value to consumers of around $0.43 million (real, 2024) by 2027, rising rapidly thereafter as the N-1 rating is exceeded to $1,944 million by 2034.

The key elements of the "Do Nothing" supply reliability risk under the base case are shown in Figure 2–2: KTS (B1,2,5) EUE risk costs (including impact of load transfer capability)

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)

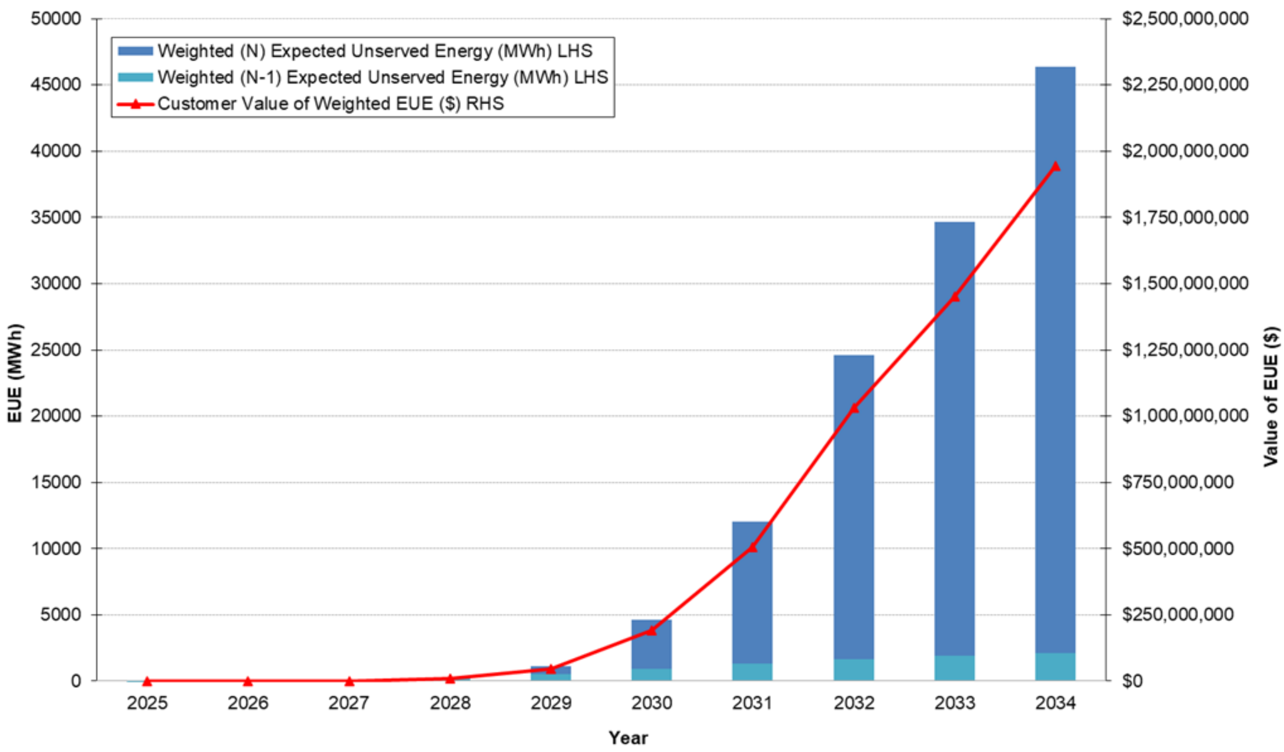


Table 2-3 summarises the forecast capacity limitations at KTS (B3,4), considering the impacts of the moderated major customer data-centre connections load forecast (described in section 2.1.2) on the overall demand at KTS (B3,4).

[10] 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.

[11] Real 2024.

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

KTS (B3,4)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load at risk above 'N' (MVA)										
Summer POE10	0	0	0	0	0	0	0	0	0	8
Winter POE10	0	0	0	0	0	0	0	0	0	0
Summer POE50	0	0	0	0	0	0	0	0	0	0
Winter POE50	0	0	0	0	0	0	0	0	0	0
Time at risk above 'N' (h pa)										
Summer POE10	0	0	0	0	0	0	0	0	0	1
Winter POE10	0	0	0	0	0	0	0	0	0	0
Summer POE50	0	0	0	0	0	0	0	0	0	0
Winter POE50	0	0	0	0	0	0	0	0	0	0
Load at risk above 'N-1' (MVA)										
Summer POE10	84	93	101	108	114	119	130	143	160	165
Winter POE10	0	0	38	47	55	61	70	82	97	113
Summer POE50	0	65	72	78	83	87	97	109	125	138
Winter POE50	0	0	28	36	43	50	59	70	86	100
Time at risk above 'N-1' (h pa)										
Summer POE10	25	33	39	45	55	67	89	130	186	233
Winter POE10	0	0	31	67	118	159	232	323	450	640
Summer POE50	0	39	45	51	58	63	74	96	122	149
Winter POE50	0	0	7	24	52	87	146	233	353	471
Weighted EUE[12]										
'N' EUE (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
'N-1' Total EUE (MWh)	0.2	1.7	2.3	3.1	4.1	5.3	8.6	15.9	30.9	51.7
Total EUE[13] (MWh)	0.2	1.7	2.3	3.1	4.1	5.3	8.6	15.9	30.9	51.8
Total Value of EUE ($m[14])	**0.01**	**0.08**	**0.11**	**0.15**	**0.19**	**0.25**	**0.41**	**0.76**	**1.48**	**2.47**

The EUE is estimated to have a value to consumers of around $0.11 million (real, 2024) by 2027, rising to $2.47 million by 2034.

The key elements of the “Do Nothing” supply reliability risk under the base case are shown in

Figure 2–3: KTS (B3,4) EUE risk costs

3 at KTS (B3,4), considering the impacts of available transfer capacity.

[12] 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.

[13] 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.

[14] Real 2024.

Figure 2–3: KTS (B3,4) EUE risk costs

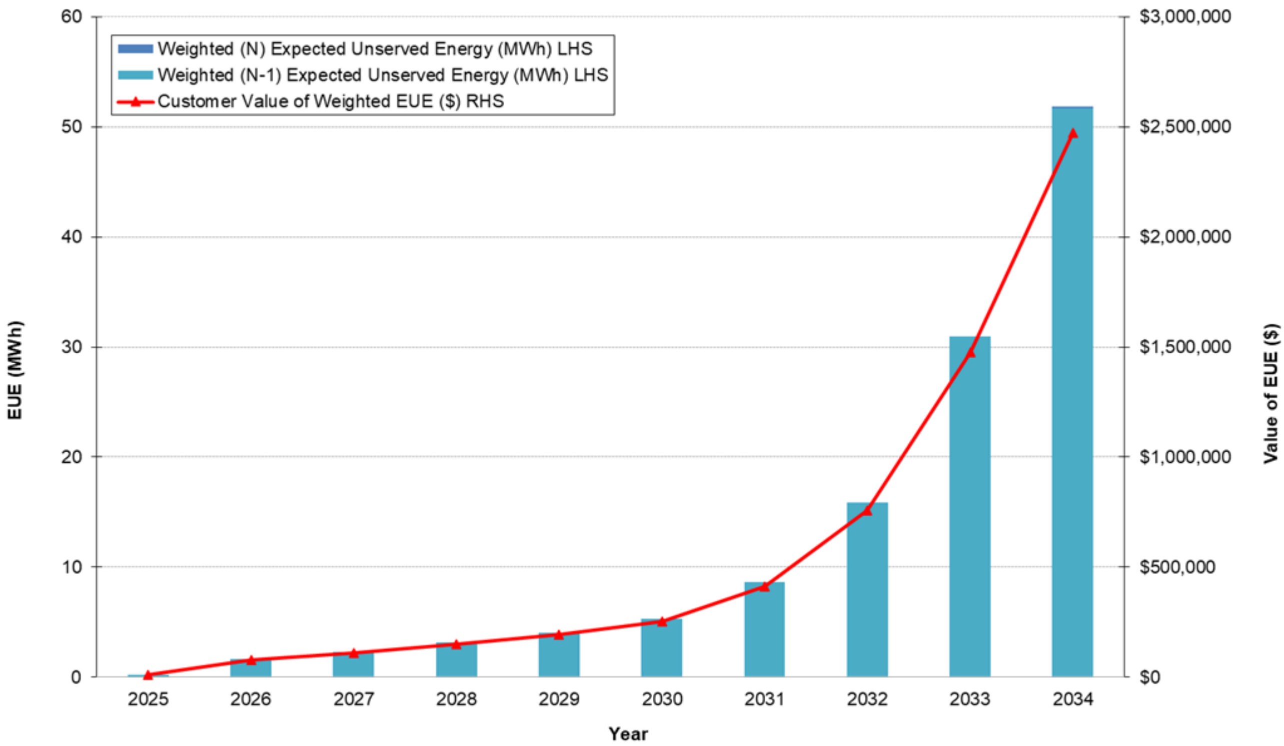


Table 2-4 summarises the forecast EUE at KTS and Table 2-5 summarises the value of the EUE (as a combined total from Table 2-2 and Table 2-3).

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

KTS EUE (MWh pa)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
POE50 (N)	-	-	-	70.8	427.7	2,994	9,288	20,539	29,818	40,695
POE50 (N-1)	-	2.3	10.0	151.0	498.4	878.9	1,239	1,624	1,866	2,113
POE10 (N)	-	-	-	149.6	1,005	5,305	14,222	28,504	39,560	52,553
POE10 (N-1)	0.8	2.4	19.0	214.5	607.8	1,031	1,439	1,855	2,116	2,385
Total (Weighted[15])	**0.2**	**2.3**	**12.7**	**264.5**	**1,132**	**4,612**	**12,067**	**24,622**	**34,682**	**46,447**

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

KTS EUE ($m, real 2024)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Weighted value of EUE	0.01	0.10	0.57	11.9	50.7	206	540	1,103	1,554	2,081

[15] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE

3. Assumptions used in identifying the identified need

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

Before doing so, we set out the overall approach to the Net Present Value (**NPV**) analysis under the RIT-T, and how options to meet the identified need will be assessed as part of the PADR. The following chapter then provides further detail on key assumptions that JEN and Powercor currently expect to adopt for the PADR assessment.

3.1 Overview of approach to the NPV analysis

Consistent with the RIT-T NER requirements[16], cost benefit analysis guidelines[17] and RIT-T application guidelines[18], JEN and 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.

Our proposed assessment method for the PADR is explained in more detail in section 4.

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

- 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 the 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.

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

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

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

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

3.2 Input assumptions

The key assumptions used in 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) information; and
- value of customer reliability.

3.2.1 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 3-1 provides a summary of the capability of KTS for “N” and “N-1” conditions during summer and winter (maximum demand) seasons.

Table 3-1: 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.

3.2.2 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 the summer and winter period[19], taking into consideration the moderated major customer data-centre load forecasts.

[19] 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 3-2 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.

Table 3-2: Forecast maximum demand at KTS (B1,2,5) (MVA)

KTS (B1,2,5) MD	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Summer POE10	367	424	496	**583**	**648**	**695**	**734**	**771**	**791**	**810**
Winter POE10	288	347	414	492	**552**	**595**	**629**	**660**	**679**	**697**
Summer POE50	339	398	470	**556**	**621**	**668**	**706**	**743**	**763**	**781**
Winter POE50	276	335	402	480	**539**	**582**	**615**	**647**	**665**	**682**

KTS (B1,2,5) is expected to exceed its N rating by 2028 for a POE10 and POE50 summer maximum demand, and 2029 for a POE10 and POE50 winter maximum demand. KTS is already exceeding its N-1 rating for a POE10 summer maximum demand and is expected to exceed its N-1 rating by 2026 for a POE50 summer maximum demand, and by 2027 for a POE10 and POE50 winter maximum demand.

Figure 3-1 shows the POE10 and the POE50 forecasts of maximum demand for KTS (B1,2,5) during summer periods relative to its capacity.

Figure 3-1: Summer period maximum demand forecasts for KTS (B1,2,5)

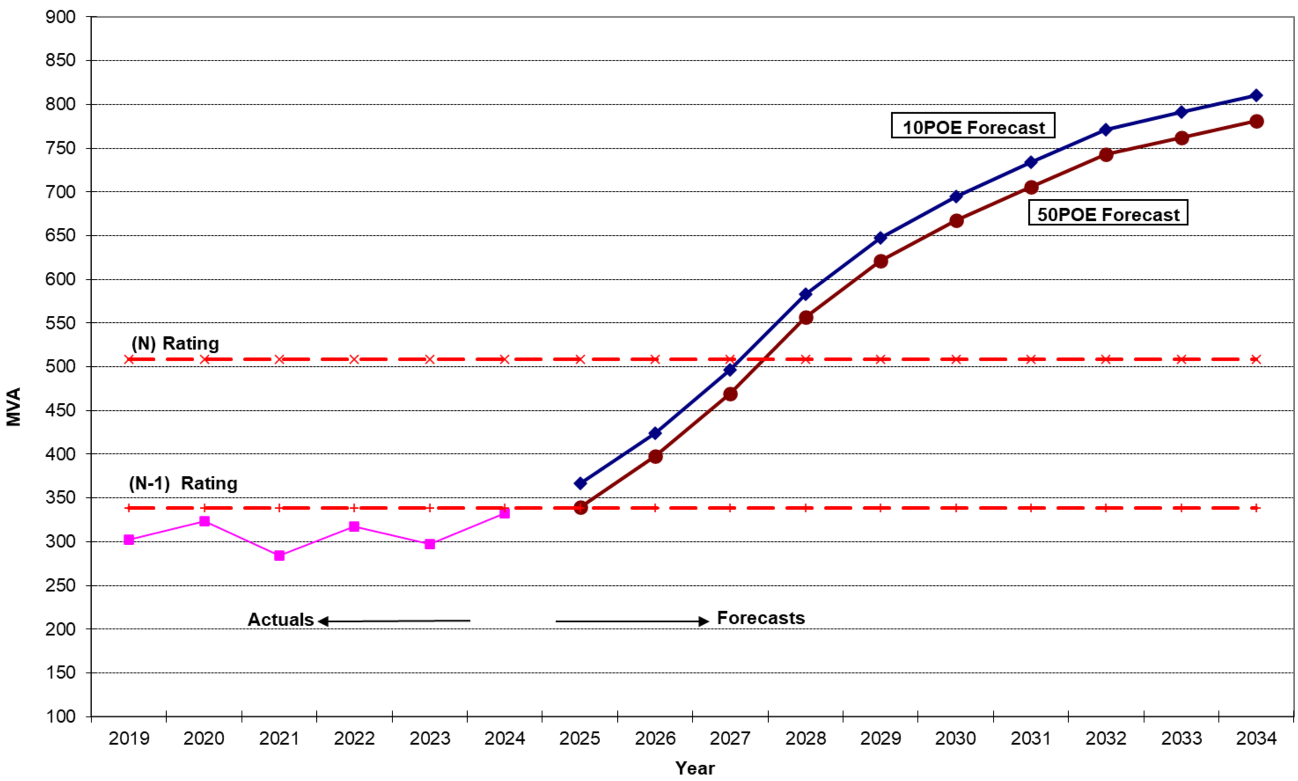


Figure 3-2 shows the POE10 and the POE50 forecasts maximum demand for KTS (B1,2,5) during winter periods relative to its capacity.

Figure 3-2: Winter period maximum demand forecasts for KTS (B1,2,5)

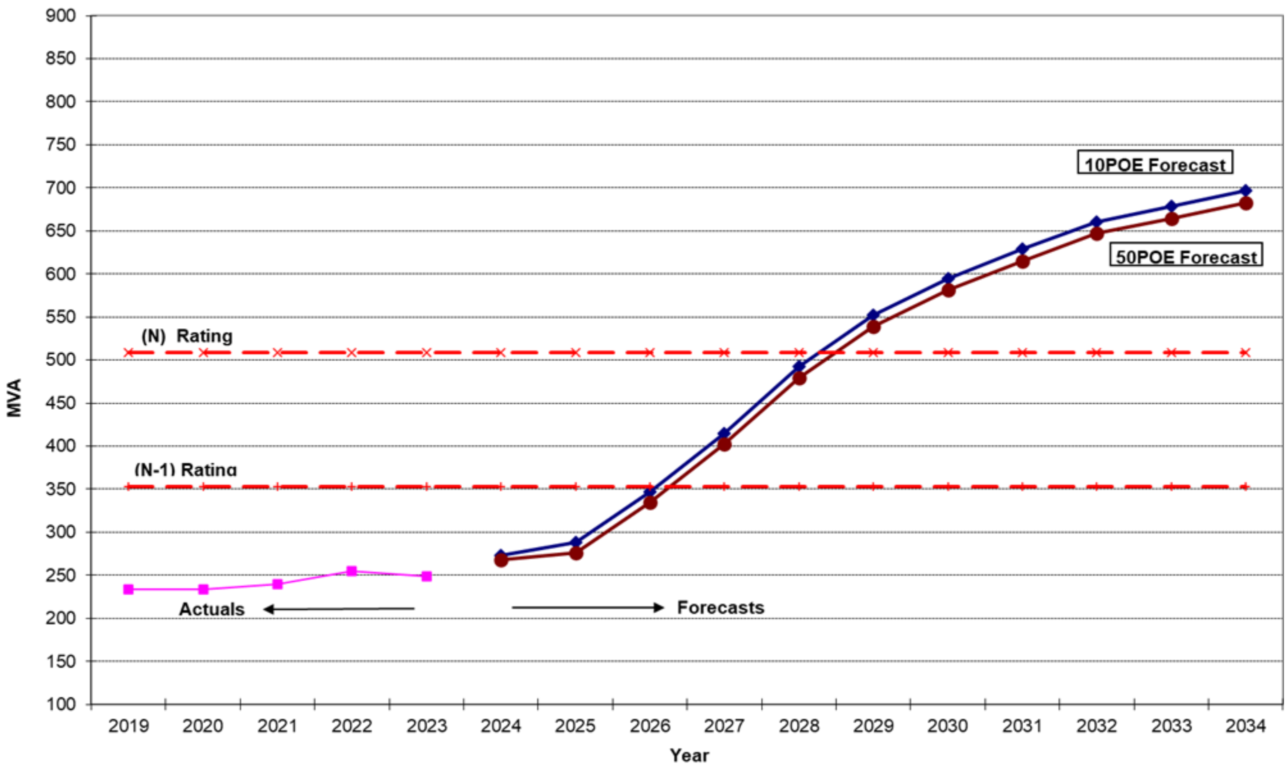


Table 3-3 provides a summary of the forecast maximum demand for KTS (B3,4) during summer and winter (maximum demand) periods. Values in red indicate that the N-1 rating is exceeded. Values in **bold underlined red** indicate that N rating is exceeded.

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

KTS (B3,4) MD	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Summer POE10	249	259	266	274	279	285	295	309	325	**339**
Winter POE10	204	217	226	235	242	249	258	270	285	300
Summer POE50	223	231	237	243	248	253	262	275	290	304
Winter POE50	194	206	215	224	231	237	246	258	273	288

KTS (B3,4) is expected to exceed its N and N-1 rating by 2034 for a POE10 summer maximum demand.

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

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

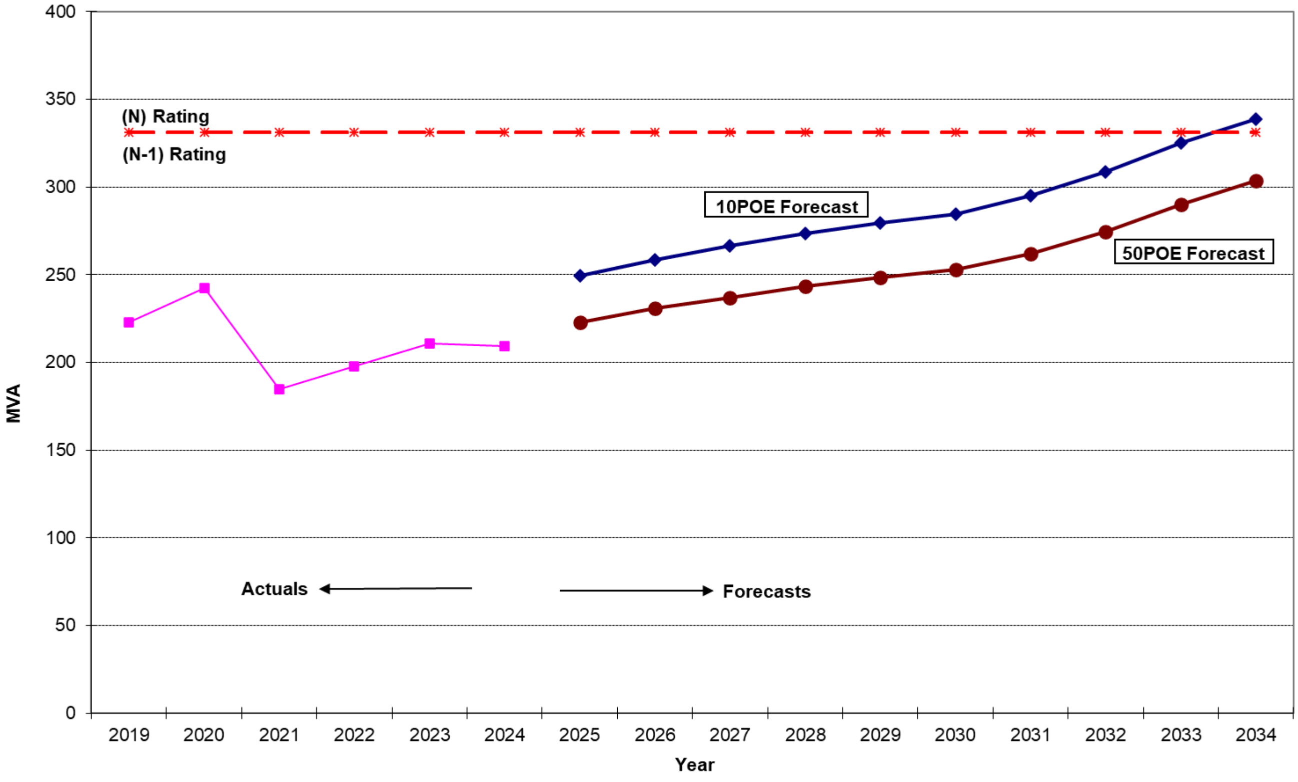
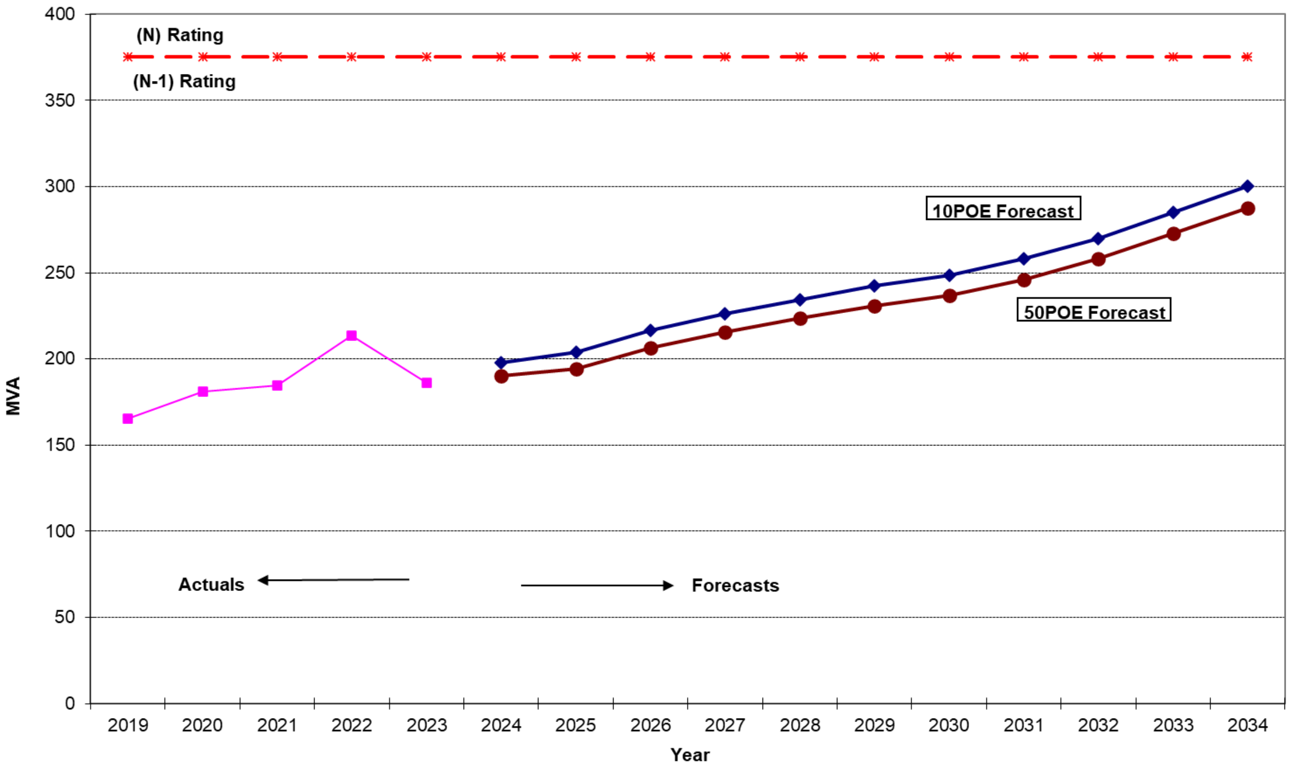


Figure 3-4 shows the POE10 and the POE50 forecasts maximum demand for KTS (B3,4) during winter periods relative to its capacity.

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



The maximum demand growth at KTS is predominately (both in magnitude and timing) on the KTS (B1,2,5) group and is due to the growth in major customer data-centre demand within the supply area.

3.2.3 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 transfer capacity is expected to be maintained over the 10-year planning horizon.

3.2.4 Annual load profile

The load-duration curves for KTS over several recent years are shown in Figure 3-5 and Figure 3-6 for peak demand periods in winter and summer seasons.

Figure 3-5: Load-duration profile for KTS (B1,2,5) at peak demand

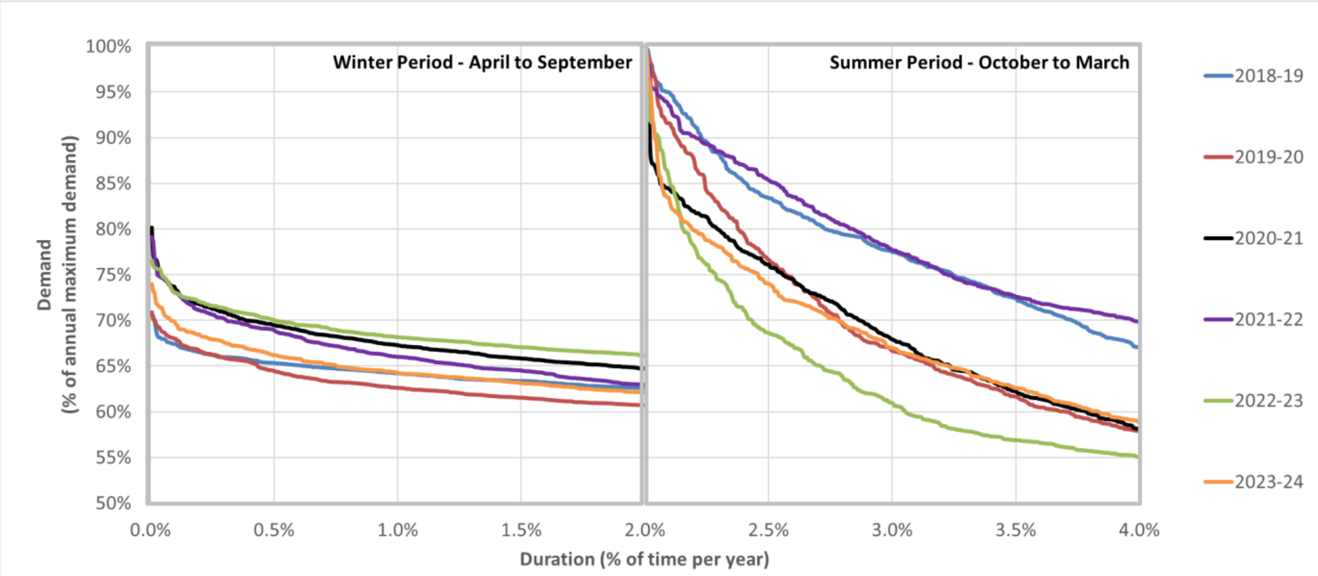
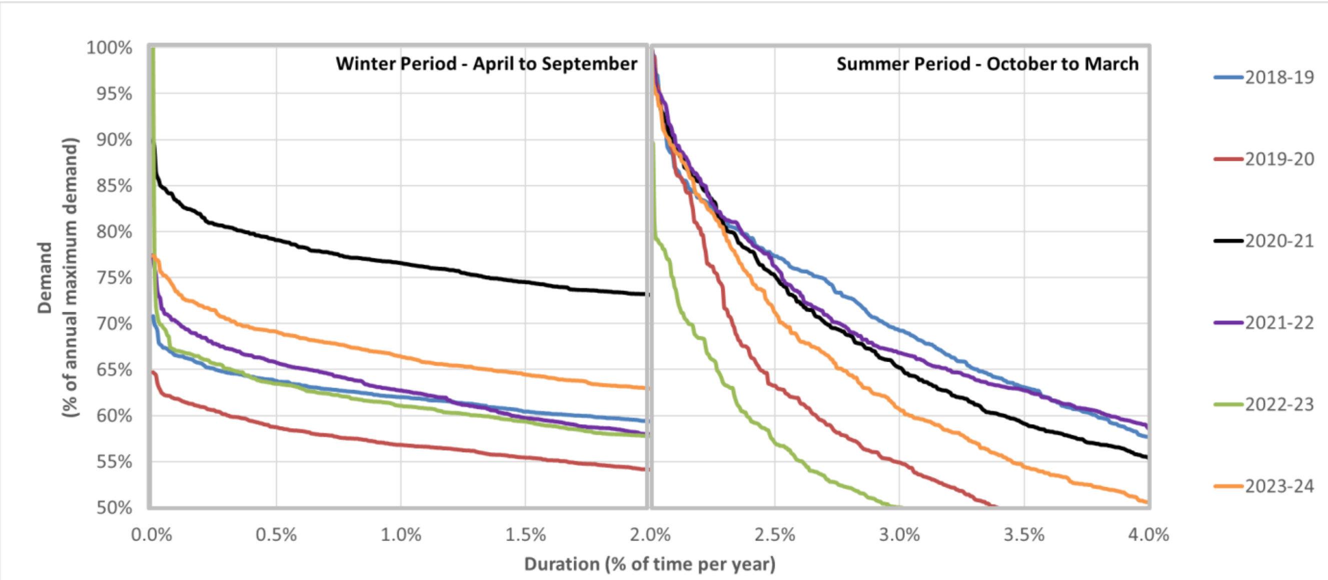


Figure 3-6: Load-duration profile for KTS (B3,4) at peak demand



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 3-7 and Figure 3-8 with the largest differences observed between the 2020-21 and 2019-20 summers.

Figure 3-7: Annual load-duration profile for KTS (B1,2,5)

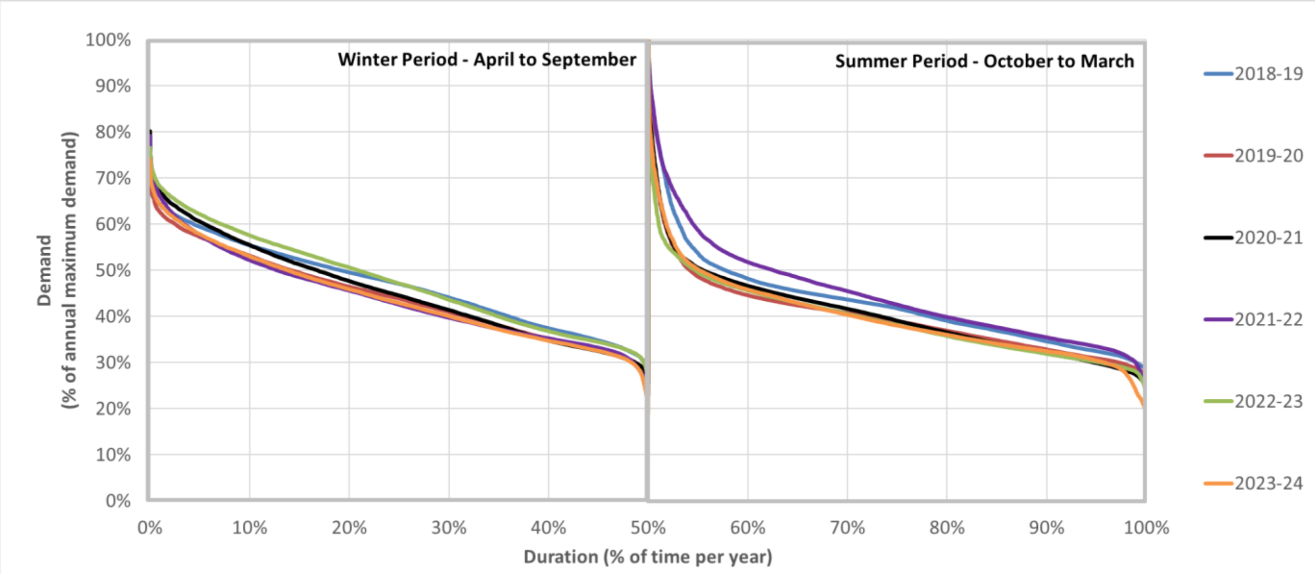
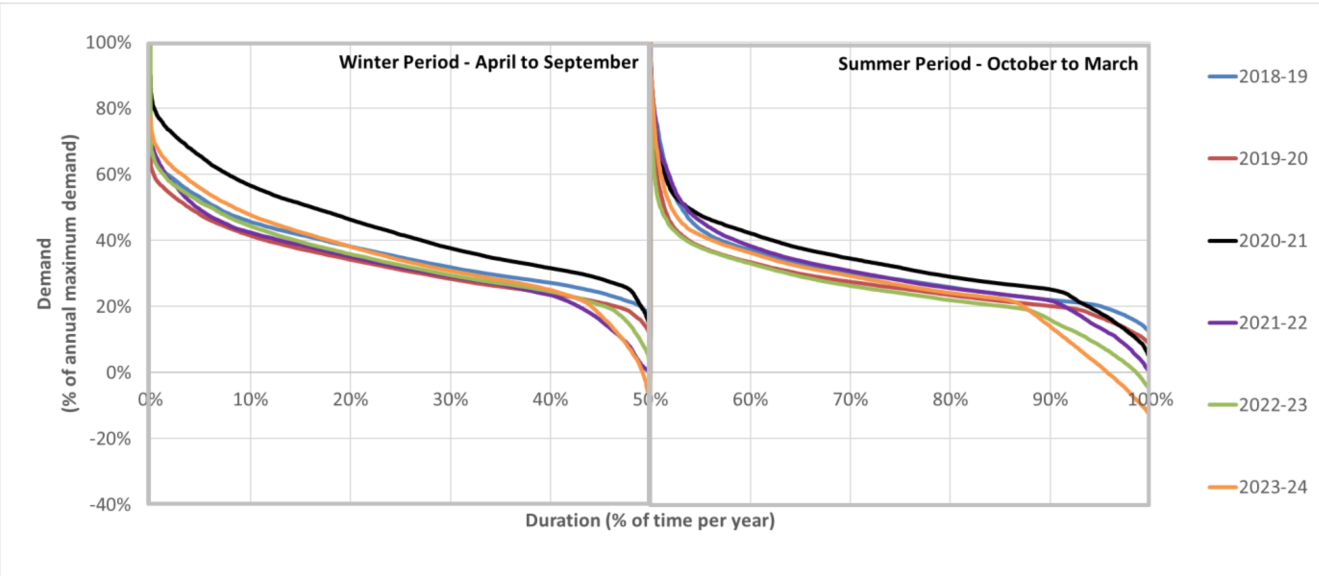


Figure 3-8: Annual load-duration profile for KTS (B3,4)



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 3-9 and Figure 3-10.

Figure 3-9: Daily load profile for KTS (B1,2,5) (summer peak demand)

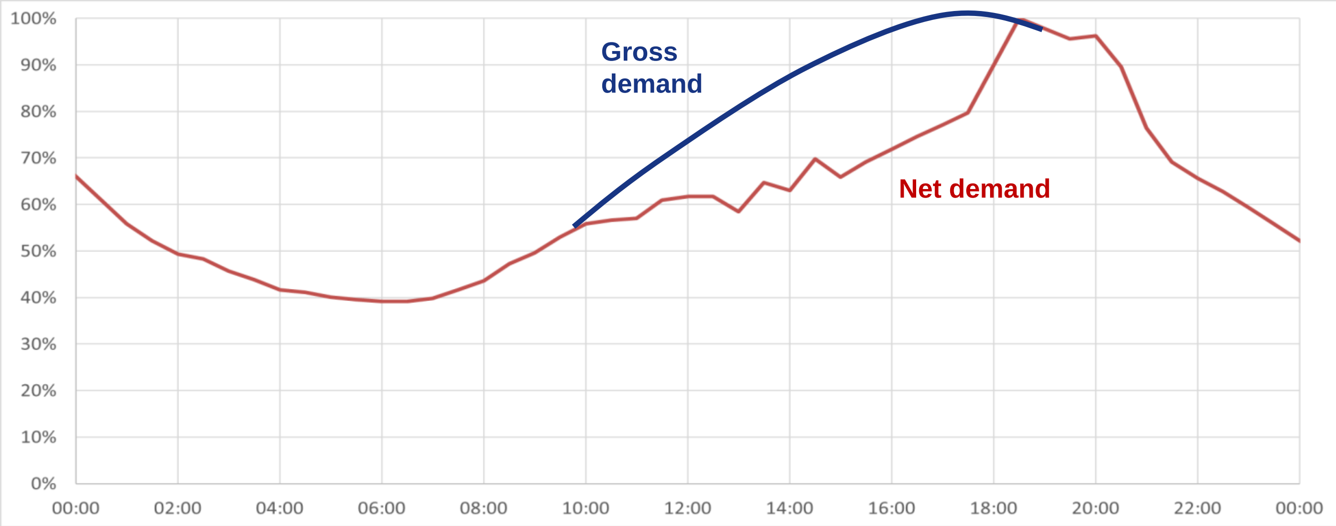
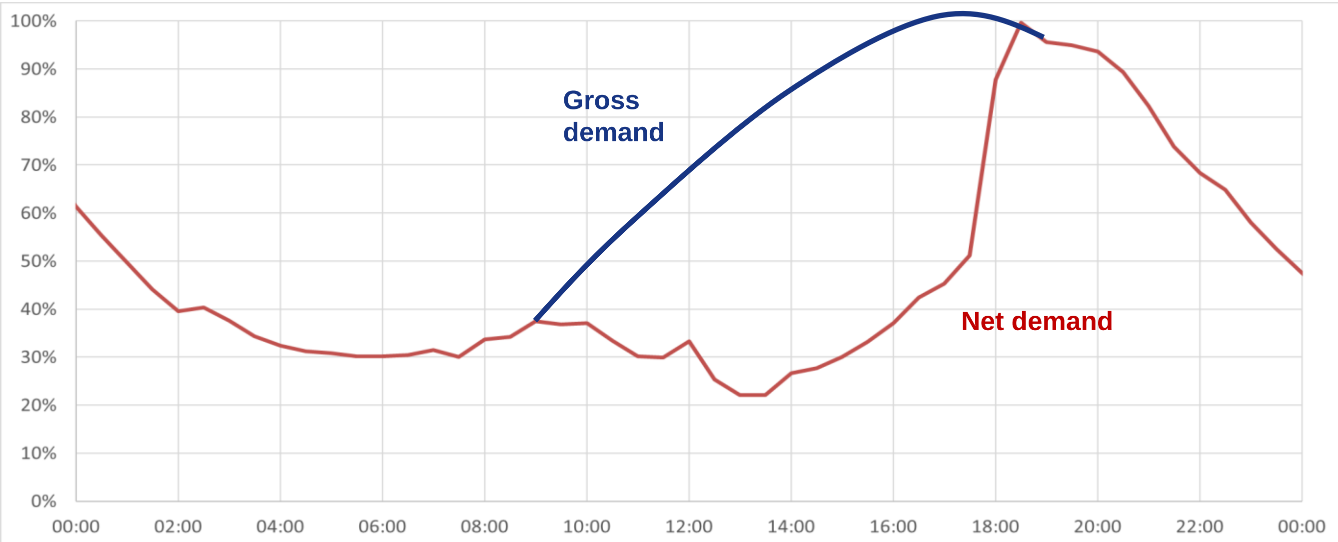


Figure 3-10: Daily load profile for KTS (B3,4) (summer peak demand)



3.2.5 Network asset reliability

Table 3-4 provides a summary of the KTS transformer reliability information used in the EUE analysis.

Table 3-4: KTS transformer reliability information

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)	2.65 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.

3.2.6 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[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 following VCRs for KTS (presented in Table 3-5 and Table 3-6), with the aggregated value for KTS being $44,811 per MWh.

Table 3-5: 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[21]	33,100	5.0%	1,645
Industrial	33,490	12.4%	4,163
Composite		**100%**	**41,906**

Table 3-6: 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[21]	33,100	0.0%	0
Industrial	33,490	4.8%	1,614
Composite		**100%**	**47,716**

[21] Greater than 10 MW.

4. Proposed assessment methodology

This chapter discusses key parameters relating to the NPV assessment of options under this RIT-T, which will form the key focus on the PADR assessment.

4.1 Assessment period

We intend to undertake the NPV analysis over a ten-year period, from 2025 to 2034. 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 (moderated) 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 moderation 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 ten years, we intend to 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 ten-year assessment period.

4.2 Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. The discount rate used in this RIT-T will be a regulatory discount rate of 4.69 per cent.

4.3 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 2024 dollars based on the information available at the time of preparing this report. Overheads comprise approximately 6.7% of the total costs, financing charges of 4.0%, and contingency risk of 5.8%.

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.

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.

4.4 Materiality of market benefits

The NER require 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:

- 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 avoided EUE is the only class of market benefit that will be material to the RIT-T assessment. We will review this expectation at the PADR stage, having regard to any submissions to the PSCR including from non-network option proponents.

We expect that the following classes of market benefits will not be material to the RIT-T assessment for any of the credible options:

- **Avoided unrelated network expenditure**, as we do not expect the options to affect other proposed network expenditure;
- **Wholesale market benefits,** including changes in fuel consumption arising through different patterns of generation dispatch changes in voluntary load curtailment, and changes in costs for parties other than JEN and Powercor, because we do not expect the credible options to have a material market on generation dispatch in the wholesale market;
- **Changes in Australia's greenhouse gas emissions**, as we do not expect the credible options to affect emissions through dispatch or through changes in SF_6 emissions;
- **Changes in network losses**, as any network losses outside of those that are captured through the network capacity assumptions feeding into the EUE analysis are not expected to be material to the ranking of options;
- **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 estimated cost of undertaking the analysis to quantify these changes would likely be disproportionate to the scale of the credible options being considered in this report; and
- **Competition benefits**, because the estimated cost of undertaking the analysis to quantify competition benefits would likely be disproportionate to the scale of the credible options being considered in this report.

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

This chapter outlines the technical characteristics that a non-network or SAPS option would be required to deliver in the form of network support services, to alleviate the forecast capacity limitations at KTS.

5.1 Performance requirements

Initial analysis by JEN and Powercor has identified that Option 3 is likely to be the preferred network option with an annualised cost of $5.4 million (real, 2024) which represents the maximum available annual payment that could be available to non-network or SAPS providers (in aggregate) for a network support option.

Based on the results of Table 2-5, the EUE risk exceeds the annualised cost of the preferred network option in the summer of 2027-28, which represents the latest date that a network support service needs to be in place to defer the preferred network option.

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

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

The amount of network support that JEN and Powercor are seeking from a full non-network or SAPS option by summer 2027-28 is 170 MW at KTS (B1,2,3) and 108 MW at KTS (B3,4), post-contingent. This would need to increase in the following years according to Table 2-2 and Table 2-3 respectively. By 2027-28, pre-contingent services would also be required, starting from 74 MW at KTS (B1,2,3). Lower levels of support may be able to be combined with other network or non-network solutions, as described above.

The magnitude and duration for each of KTS (B1,2,5) and KTS (B3,4) network support services required under various seasonal, loading and network operating conditions (considering the likelihood of those conditions), is detailed in Table 2-2 and Table 2-3, with the indicative time of day requirements shown in Figure 3-9 and Figure 3-10, respectively.

5.2 Submission requirements

Non-network and SAPS service providers interested in providing submissions to alleviate the network limitations outlined in this PSCR are advised to begin engagement with JEN and 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.

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

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

1. JEN Industry Engagement Strategy.

2. Powercor Industry Engagement Document.

6. Description of potential credible options

This chapter lists and describes options that JEN and Powercor consider 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). 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 66 kV buses and two new transformers;
- Option 5 - Establish a new 500/220/66 kV switchyard at Sydenham Terminal Station (SYTS);
- Option 6 - Establish a new 220/66 kV terminal station.

All of these options (except for Option 1) would increase the thermal capacity of KTS or result in additional capacity at another (or new) terminal station. Table 6-1 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 6-1: Thermal capacity ratings of each option (MVA)

KTS 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	530	530
Summer (N-1)	339	331	530	331	265	265
Winter (N)	509	375	879	560	586	586
Winter (N-1)	353	375	586	375	293	293

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.

6.1 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 $0.01 in 2024-25 to $11.9 million in 2027-28, to $2,081 million by 2033-34 (real, 2024).

In the context of this RIT-T, the “Do nothing” option is used as a base case to which all other credible options will be compared, to identify the option that maximises the present value of net economic benefit. Furthermore, since no incremental expenditure is implemented under the “Do nothing” option, the “Do nothing” option is considered a zero-cost and zero-benefit option.

6.2 Option 2 - Non-network or SAPS solution

Non-network or SAPS options may be 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.

Chapter 5 details the required technical characteristics as well as the maximum network support payments potentially available to a non-network or SAPS service provider, based on the current preferred network option. Network support may also be combined with suitable network augmentation components to defer or reduce the scope of a credible network option.

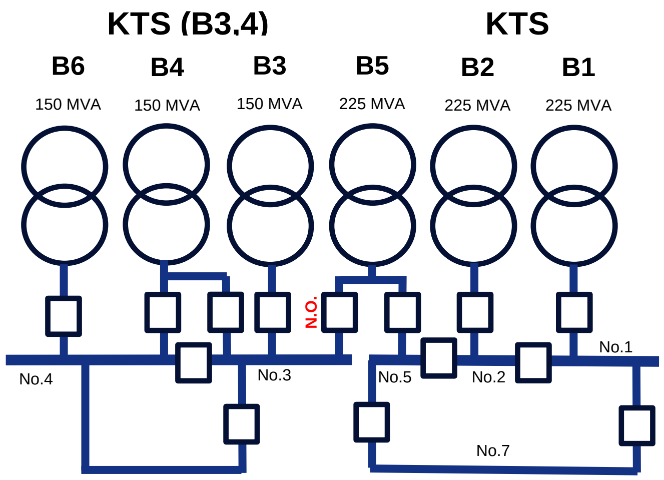
6.3 Option 3 - Upgrade all three transformers at KTS (B1,2,5), and install a new third transformer at KTS (B3,4)

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 6-1.

Figure 6-1: KTS 66 kV simplified single line diagram (Option 3)



The estimated capital cost of this network option is $91 million (real $2024), with ongoing operations and maintenance costs of $0.9 million per annum.

The annualised cost of this option is $5.4 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) is before summer 2027-28.

This option has an estimated construction period of two to three years.

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.

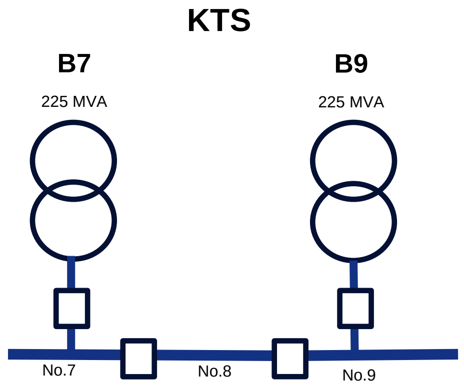
Based on an initial assessment, this option is currently expected to maximise the net market benefits and is therefore likely to be the preferred network option. However this conclusion will be confirmed through this RIT-T process.

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

This option involves installing a new 66 kV switchyard within KTS with new B7 and B9 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 and B9 into the 220 kV shared transmission assets.

A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 6-2.

Figure 6-2: KTS (B7,8,9) 66 kV simplified single line diagram (Option 4)



The estimated capital cost of this network option is $100 million (real $2024), with ongoing operations and maintenance costs of $1.0 million per annum.

The annualised cost of this option is $5.9 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) is before summer 2027-28.

This option has an estimated construction period of two to three years.

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.

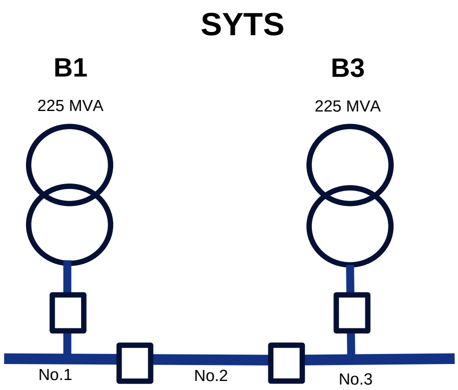
Social licencing risks are considered minor for this option as it only involves work within an existing established substation. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

6.5 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 new B1 and B3 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 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 6-3.

Figure 6-3: SYTS 66 kV simplified single line diagram (Option 5)



The estimated capital cost of this network option is $250 million (real $2024), with ongoing operations and maintenance costs of $1.3 million per annum.

The annualised cost of this option is $15.1 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) is before summer 2028-29.

This option has an estimated construction period of three years.

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.

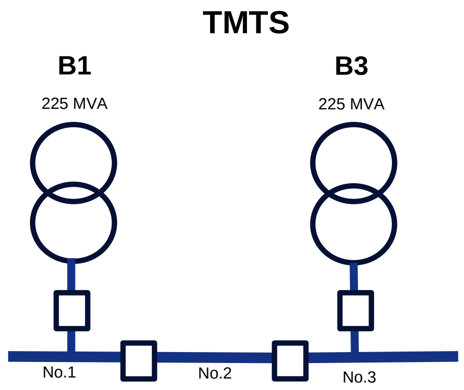
Social licencing risks are considered moderate for this option as even though it only involves work within an existing established substation, the scale of the works is substantial requiring works at 500 kV. The social licensing risks are expected to increase over time as the surrounding area becomes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

6.6 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 new B1 and B3 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 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 6-4.

Figure 6-4: TMTS 66 kV simplified single line diagram (Option 6)



The estimated capital cost of this network option is $200 million (real $2024), with ongoing operations and maintenance costs of $1.0 million per annum.

The annualised cost of this option is $11.1 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) is before summer 2028-29.

This option has an estimated construction period of four years.

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.

7. Submissions and next steps

7.1 Request for submissions

JEN and Powercor invites written submissions and enquiries on the matters set out in this PSCR 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

rittenquiries@powercor.com.au

The consultation on this PSCR is open for 12 weeks. Submissions are due on or before 5 September 2025.

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.

7.2 Next steps

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

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

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

JEN and Powercor intend on publishing the PADR by the third quarter of 2025.

8. Appendix A – RIT-T compliance checklist

This appendix sets out a checklist in Table 8-1 which demonstrates the compliance of this PSCR with the requirements of clause 5.16.4(b) of the NER, version 225.

Table 8-1: 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 5
(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 6
(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 4 & 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 8-2: AER guidelines PSCR compliance checklist

Summary of the requirements:	Chapter
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 4
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 6