# TRANSMISSION CONNECTION PLANNING REPORT
Produced jointly by the five Victorian Electricity Distribution Businesses

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EXECUTIVE SUMMARY

This document sets out a joint report on transmission connection asset planning in Victoria, prepared by the five Victorian electricity Distribution Businesses (“the DBs”)¹, in accordance with the transmission connection planning requirements of Clause 3.4 of the Victorian Electricity Distribution Code and clause 5.13.2 of the National Electricity Rules (the Rules).

Under their Electricity Distribution Licences, the DBs have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the shared transmission network². The assets connecting the DBs’ distribution networks to the shared transmission network are known as transmission connection assets. Those assets provide prescribed transmission services in accordance with Chapter 6A of the Rules. All current connection assets are located within terminal stations which are owned, operated, and maintained by the transmission asset owner, AusNet Transmission Group. The connection assets at the Deer Park terminal station - which are expected to be commissioned by late 2017 - will be owned, operated and maintained by TransGrid.

The Victorian jurisdiction has not set deterministic planning standards that apply to transmission connection assets. However, clause 5.2 of the Victorian Electricity Distribution Code sets out requirements relating to reliability of supply, and it requires the DBs to use best endeavours to meet, among other things, reasonable customer expectations of reliability of supply.

For the purpose of identifying emerging constraints, and subject to meeting the standards in schedule 5.1 of the Rules and complying with the Victorian Electricity Distribution Code, the DBs apply a probabilistic planning approach. That approach involves estimating the probability of a transmission plant outage occurring, and weighting the costs of such an occurrence by its probability. This calculation enables the assessment of:

- the expected amount (and value) of energy that will not be supplied under a ‘do nothing’ scenario, and therefore
- whether it is economic to take action to reduce or eliminate the expected supply interruptions.

The DBs’ approach is consistent with the probabilistic approach applied by AEMO in planning the Victorian shared transmission network³. An important point to note about the use of a probabilistic approach is that it involves customers accepting the risk that there may be circumstances when the available terminal station capacity will be insufficient to meet actual demand, and significant load shedding could be required.

An estimate of the value that customers place on supply reliability (“VCR”) is a key input to probabilistic network planning. Estimating the VCR is inherently uncertain, and AEMO’s current estimate (published in its September 2014 VCR Final Report⁴) is substantially lower.

¹ The five DBs are: Jemena Electricity Networks (Vic) Ltd, CitiPower, Powercor Australia, United Energy, and AusNet Electricity Services Pty Ltd. AusNet Electricity Services is owned by AusNet Services, a diversified energy infrastructure business that also owns the Victorian electricity transmission system. Throughout this document “AusNet Transmission Group” refers to the transmission business of AusNet Services and “AusNet Electricity Services” refers to the electricity distribution business of AusNet Services.

² The shared transmission network is the main extra high voltage network that provides or potentially provides supply to more than a single point. This network includes all lines rated above 66 kV and main system tie transformers that operate at two or three voltage levels above 66 kV.


than its previous estimate. In the 2015 Transmission Connection Planning Report, we highlighted the impact of AEMO’s lower VCR estimate by reporting the investment signals using both the current and previous estimates where the change in VCR has a material impact on the timing of augmentation over the next 5 years. We adopt the same approach in this report.

Where application of AEMO’s current VCR estimates produces a materially different investment signal (and hence different reliability outcomes and risks for customers) compared to its previous estimate, the DBs will undertake further analysis, which may include customer consultation. Customer consultation may be particularly helpful in determining the investment timing that would meet customers’ expectations of supply reliability as required by clause 5.2 of the Victorian Electricity Distribution Code.

In accordance with Part B (Network Planning and Expansion) of Chapter 5 of the Rules, the planning standard applied by the DBs in relation to transmission connection assets is the Regulatory Investment Test for Transmission (RIT-T), the purpose of which is set out in clause 5.16.1(b) of the Rules as follows:

“To identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.”

It is noted that “reliability corrective action” involves investment (which may consist of network or non-network options) to satisfy the technical requirements of schedule 5.1 of the Rules or an applicable regulatory instrument, such as the Victorian Electricity Distribution Code.

The assessment presented in this report, and summarised in the table on the following pages sets out the DBs’ Transmission Connection Planning Report for 2016. It is emphasised that this report does not present the detailed investment decision analysis that is required under the RIT-T. Rather, the report presents a high-level indication of the expected balance between capacity and demand at each terminal station over the forecast period.

The demand forecasts used in the preparation of this report are those set out in the 2016 Terminal Station Demand Forecasts (TSDF). The TSDF is compiled from forecasts provided by Victorian participants (being the Victorian DBs and directly connected customers), and they reflect participants’ expectations of future demand.

Data presented in this report may indicate an emerging major constraint. Therefore, this report provides a means of identifying those terminal stations where further detailed consultation and analysis, in accordance with the RIT-T, is required. This report also provides preliminary information on potential opportunities to prospective proponents of alternatives to network augmentations at terminal stations where remedial action may be required. Providing this information to the market should facilitate the efficient development of network and non-network solutions to best meet the needs of end-customers.

The DBs are required by clause 3.4 of the Victorian Electricity Distribution Code to provide, among other things, an indication of the magnitude, and potential impact of loss of load for each transmission connection.
This information is summarised in the table on the following pages, in the form of estimates of “expected unserved energy”\(^5\) for each terminal station in the year in which augmentation of the terminal station is likely to be required. Expected unserved energy estimates are provided for two forecasts of demand: the first forecast has a 10% probability of being exceeded, while the second forecast has a 50% probability of being exceeded.

AEMO’s 2014 VCR estimate has been escalated to 2016 values using the escalation adjustment set out in AEMO’s VCR Application Guide. The 2016 VCR and AEMO’s previous VCR estimate (also escalated to 2016 dollars) are used to calculate expected unserved energy, and to provide an indication of the timing of remedial action to address an emerging constraint. As already noted, where the application of AEMO’s previous VCR estimate gives rise to a material impact on the timing of augmentation over the next 5 years, this is noted in the table.

For each terminal station, the table also identifies alternatives to network augmentation that may alleviate constraints. Following the summary table is a map showing the approximate locations of the existing AusNet Transmission Group-owned connection terminal stations.

Unless noted otherwise in this report including the accompanying risk assessment documents, the relevant DB(s) have not identified any issues relating to compliance with applicable standards that would be likely to drive the need for augmentation of transmission connection assets at this time.

It is noted that as conditions change and as new information becomes available, the indicative timing of any remedial action required to address an emerging constraint or possible non-compliance with an applicable standard may also change. For instance, changes in demand forecasts from one year to the next may result in changes in the timing of remedial action at some stations. Further details are set out in the individual risk assessments for each of the terminal stations.

Parties seeking further information about any matter contained in this report should contact any one of the following people:

- Neil Gascoigne, Planning Policy & Transmission Interface Manager, CitiPower / Powercor, phone 9683 4472.
- Tom Langstaff, Lead Engineer, Subtransmission Network Planning, AusNet Electricity Services, phone 9695 6859.
- Rodney Bray, Manager Network Planning and Strategy, United Energy, phone 8846 9745.
- Ashley Lloyd, Network Capacity Planning and Assessment Manager, Jemena, phone 9173 8279.

Any of these contact officers will either be able to answer your queries or will direct you to the organisation that is best placed to provide you with the information you are seeking.

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\(^5\) Throughout this report, the terms “energy at risk” and “expected unserved energy” are used to provide an indication of the magnitude, and potential impact of loss of load for each terminal station. In this report:

“Energy at risk” is, for a given forecast of demand, the total energy that would not be supplied from a terminal station if: a major outage of a transformer occurs at that station in a specified year; the outage has a mean duration of 2.6 months; and no other mitigation action is taken. This statistic provides an indication of the magnitude of loss of energy that would arise in the unlikely event of a major outage of a transformer.

“Expected unserved energy” is the energy at risk weighted by the probability of a major outage of a transformer, where a “major outage” is defined as one that has a mean duration of 2.6 months. This statistic provides an indication of the amount of energy, on average, that will not be supplied in a year, taking into account the very low probability that one transformer at the station will not be available because of a major outage.
Summary of risk assessment and options for alleviation of constraints

<table>
<thead>
<tr>
<th>Terminal Station</th>
<th>Indicative timing for completion of preferred network solution (using 2016 VCR)</th>
<th>Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2016 VCR)</th>
<th>Preferred network solution</th>
<th>Indicative annual cost of preferred network solution</th>
<th>Potentially feasible non-network solutions</th>
</tr>
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<tbody>
<tr>
<td>Altona – Brooklyn (ATS/BLTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Altona no 3 &amp; 4 (ATS West) 66 kV</td>
<td>By 2026. (or 2022 based on AEMO’s previous VCR estimate escalated to 2016 dollars)</td>
<td>130 MWh ($4.7 million) 54.5 MWh ($2 million)</td>
<td>Install additional transformation capacity and reconfigure 66 kV exits at ATS.</td>
<td>$1.8 million</td>
<td>Demand reduction; Local generation.</td>
</tr>
<tr>
<td>Ballarat (BATS)</td>
<td>Not before 2026</td>
<td>0.65 MWh in 2017 ($25,000) Nil</td>
<td>Demand is forecast to decline marginally over the forecast period from 2017 levels. There are presently several large 66 kV wind farm proposals in the area which may drive the need for an additional 220/66 kV transformer at BATS to accommodate the reverse power flow expected at BATS.</td>
<td>$1.4 million to install a third 150 MVA 220/66 kV transformer</td>
<td>Demand reduction</td>
</tr>
<tr>
<td>Bendigo 22 kV (BETS 22 kV)</td>
<td>The need for augmentation is not expected to arise over the next ten years.</td>
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<tr>
<td>Bendigo 66 kV (BETS 66 kV)</td>
<td>Not before 2026</td>
<td>11.7 MWh in 2017 ($0.46 million) 4.0 MWh in 2017 ($0.16 million)</td>
<td>Install an additional 150 MVA 220/66 kV transformer. Note that demand at BETS 66 is expected to decrease over the forecast period. Therefore, over the forecast period, the expected unserved energy is also expected to decline from the levels forecast for 2017. On the basis of the present demand forecasts, augmentation of capacity at the station is unlikely to be economically justified within the ten year planning horizon.</td>
<td>$1.4 million</td>
<td>Demand reduction; Local generation</td>
</tr>
<tr>
<td>Terminal Station</td>
<td>Indicative timing for completion of preferred network solution (using 2016 VCR)</td>
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<td>10\textsuperscript{th} percentile demand forecast</td>
<td>50\textsuperscript{th} percentile demand forecast</td>
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<tr>
<td>Brooklyn 22 kV (BLTS 22 kV)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Brunswick 22 kV (BTS 22 kV)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Brunswick 66 kV (BTS 66 kV)</td>
<td>BTS 66 kV will be a new 66 kV source of supply, to be established with 3 x 225 MVA 220/66 kV transformers. BTS 66 kV is a committed project and is expected to be commissioned in late 2016 to reinforce the security of supply to the northern and inner suburbs and the Central Business District areas, and to provide future supply to the nearby suburbs of Brunswick, Brunswick West, Northcote, Carlton, Fitzroy and Collingwood. Once BTS 66 kV is established, the need for augmentation or other corrective action at the station is not expected to arise over the ten year planning horizon.</td>
<td>243 MWh in 2024 ($8.67 million)</td>
<td>33.1 MWh in 2024 ($1.18 million)</td>
<td>Install a fourth transformer.</td>
<td>$2 million Demand reduction; Local Generation. Recent reductions in demand forecasts for CBTS have enabled AusNet Electricity Services and United Energy to suspend negotiations with a proponent of network support arrangements. Network support would enable deferral of augmentation.</td>
</tr>
<tr>
<td>Cranbourne 66 kV (CBTS 66 kV)</td>
<td>2024, in the absence of network support arrangements (or 2022 based on AEMO’s previous VCR estimate escalated to 2016 dollars)</td>
<td>243 MWh in 2024 ($8.67 million)</td>
<td>33.1 MWh in 2024 ($1.18 million)</td>
<td>Install a fourth transformer.</td>
<td>$2 million Demand reduction; Local Generation. Recent reductions in demand forecasts for CBTS have enabled AusNet Electricity Services and United Energy to suspend negotiations with a proponent of network support arrangements. Network support would enable deferral of augmentation.</td>
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<tr>
<td>Deer Park (DPTS)</td>
<td>DPTS 66 kV is a committed future terminal station located at the corner of Christies Road and Riding Boundary Road in Deer Park. It is required to offload both transformer groups at KTS by November 2017 to avoid excessive load at risk and load exceeding 'N' ratings of plant at KTS in summer 2017/18. The establishment of DPTS will enable a large amount of augmentation work at ATS West and ATS/BLTS to be deferred. Powercor, Jemena Electricity Networks and AEMO published a regulatory test analysis of the proposed Deer Park Terminal station in May 2012. A copy of the report is available at: <a href="http://www.powercor.com.au/West_Metro_SubTransmission/">http://www.powercor.com.au/West_Metro_SubTransmission/</a>. Following its commissioning in late 2017, there will be sufficient capacity at the station to supply all expected demand at the 10\textsuperscript{th} and 50\textsuperscript{th} percentile temperature, over the forecast period, even with one transformer out of service.</td>
<td>243 MWh in 2024 ($8.67 million)</td>
<td>33.1 MWh in 2024 ($1.18 million)</td>
<td>Install a fourth transformer.</td>
<td>$2 million Demand reduction; Local Generation. Recent reductions in demand forecasts for CBTS have enabled AusNet Electricity Services and United Energy to suspend negotiations with a proponent of network support arrangements. Network support would enable deferral of augmentation.</td>
</tr>
<tr>
<td>East Rowville (ERTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
<td>243 MWh in 2024 ($8.67 million)</td>
<td>33.1 MWh in 2024 ($1.18 million)</td>
<td>Install a fourth transformer.</td>
<td>$2 million Demand reduction; Local Generation. Recent reductions in demand forecasts for CBTS have enabled AusNet Electricity Services and United Energy to suspend negotiations with a proponent of network support arrangements. Network support would enable deferral of augmentation.</td>
</tr>
<tr>
<td>Terminal Station</td>
<td>Indicative timing for completion of preferred network solution (using 2016 VCR)</td>
<td>Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2016 VCR)</td>
<td>Preferred network solution</td>
<td>Indicative annual cost of preferred network solution</td>
<td>Potentially feasible non-network solutions</td>
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<tr>
<td>Fishermans Bend (FBTS)</td>
<td>On 17 November 2016, the B1 transformer unit at FBTS had an internal fault requiring it to be replaced permanently with a 150 MVA metropolitan spare transformer. The replacement is planned to be completed before the end of December 2016. Once the replacement transformer is installed, no augmentation of capacity is expected to be required within the ten year planning horizon.</td>
<td>0.8 MWh ($28,000)</td>
<td>Establish a new 220/66 kV terminal station in Dandenong. This option alleviates a number of emerging transmission, connection asset and sub-transmission limitations including at HTS.</td>
<td>$7 million</td>
<td>Demand reduction; Local Generation</td>
</tr>
<tr>
<td>Frankston (FTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
<td>0.1 MWh ($2,300)</td>
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<tr>
<td>Geelong (GTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Glenrowan (GNTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Heatherton (HTS)</td>
<td>Not before 2026</td>
<td>43.8 MWh in 2016/17 ($1.7 million)</td>
<td>Construction of a new Terminal Station at Deer Park has commenced and is expected to be completed before summer 2017/18. Jemena Electricity Networks and Powercor have established contingency plans to manage the demand over the summer of prior to the establishment of Deer Park Terminal Station</td>
<td>$12.5 million for the new Terminal Station.</td>
<td>Demand reduction; Local generation.</td>
</tr>
<tr>
<td>Horsham (HOTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<td>Heywood (HYTS 22 kV)</td>
<td>A 22 kV point of supply was established in late 2009, by utilising the tertiary 22 kV on the existing 2 x 500/275/22 kV South Australian / Victorian interconnecting transformers. The station presently supplies a small number of customers in the local area. There is sufficient capacity at the station to supply all expected 22 kV load over the forecast period, even with one transformer out of service.</td>
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<tr>
<td>Keilor (KTS)</td>
<td>Prior to summer 2017/18</td>
<td>43.8 MWh in 2016/17 ($1.7 million)</td>
<td>Construction of a new Terminal Station at Deer Park has commenced and is expected to be completed before summer 2017/18. Jemena Electricity Networks and Powercor have established contingency plans to manage the demand over the summer of prior to the establishment of Deer Park Terminal Station</td>
<td>$12.5 million for the new Terminal Station.</td>
<td>Demand reduction; Local generation.</td>
</tr>
<tr>
<td>Kerang (KGTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<td>Malvern 22 kV (MTS 22 kV)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Terminal Station</td>
<td>Indicative timing for completion of preferred network solution (using 2016 VCR)</td>
<td>Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2016 VCR)</td>
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<tr>
<td>Malvern 66 kV (MTS 66 kV)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Mount Beauty (MBTS)</td>
<td>At times of high demand and with low output from Clover Power Station a transformer outage at MBTS could result in the loss of some customer load for a period of no more than 4 hours, as the “hot spare” transformer at the station is brought into service. At a cost of approximately $2 million, it would not be economic to install full switching of the hot spare transformer at MBTS to eliminate this risk during the 10 year planning horizon.</td>
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<td>Morwell (MWTS)</td>
<td>Not before 2026 (assuming a total contribution of 60 MVA from existing embedded generators)</td>
<td>3 MWh in 2016/17 ($0.12 million)</td>
<td>Negligible over the ten year forecast period</td>
<td>Demand at MWTS is forecast to decline over the ten year planning period. In view of the low and declining level of expected unserved energy, there are currently no plans to implement a network solution within the ten year planning horizon.</td>
<td>N/A</td>
</tr>
<tr>
<td>Red Cliffs 22 kV (RCTS 22 kV)</td>
<td>There is sufficient capacity at the station to supply all expected load over the forecast period, with one transformer out of service under 50th percentile forecast conditions. Under 10th percentile forecast conditions, there is load at risk from 2023 onwards which can be managed by utilising load transfers to Mildura zone substation. Therefore, the need for augmentation is not expected to arise over the ten year planning horizon.</td>
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<tr>
<td>Red Cliffs 66 kV (RCTS 66 kV)</td>
<td>Not before 2026</td>
<td>1.05 MWh ($0.04 million)</td>
<td>0.04 MWh ($1,800)</td>
<td>A distribution reinforcement project to reconductor part of the Wemen-Robinvale 66 kV line is planned to be completed in 2018. The project is justified primarily on the basis of the risk of supply to Boundary Bend (BBD) zone substation in the event of an unforced outage at RCTS 66 kV. The project will provide sufficient capacity to transfer all the BBD forecast load in 2026 (in the order of 35 MVA) to WETS.</td>
<td>$0.4 million</td>
</tr>
<tr>
<td>Richmond 22 kV (RTS 22 kV)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Terminal Station</td>
<td>Indicative timing for completion of preferred network solution (using 2016 VCR)</td>
<td>Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2016 VCR)</td>
<td>Preferred network solution</td>
<td>Indicative annual cost of preferred network solution</td>
<td>Potentially feasible non-network solutions</td>
</tr>
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</tr>
<tr>
<td>Richmond 66 kV</td>
<td>By summer 2019/20</td>
<td>14.6 MWh in 2017 ($0.22 million)</td>
<td>Permanently transfer load away to the proposed BTS 66 kV station after it is commissioned in late 2016.</td>
<td>The establishment of the BTS 66 kV station is committed and underway.</td>
<td></td>
</tr>
<tr>
<td>(RTS 66 kV)</td>
<td>1.7 MWh in 2017 ($0.07 million)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ringwood 22 kV</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>(RWTS 22 kV)</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Ringwood 66 kV</td>
<td>.No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
<td></td>
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<tr>
<td>(RWTS 66 kV)</td>
<td></td>
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<tr>
<td>Shepparton</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
<td></td>
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<tr>
<td>(SHTS)</td>
<td></td>
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<tr>
<td>South Morang</td>
<td>2024/25 (or 2022/23 based on AEMO’s previous VCR estimate escalated to 2016 dollars)</td>
<td>108.4 MWh in 2025/26, assuming no generation from Somerton PS ($3.97 million)</td>
<td>Install a third 225 MVA 220/66 kV transformer at SMTS.</td>
<td>$2.2 million (including the cost of fault limiting reactors)</td>
<td>Demand Reduction Embedded generation</td>
</tr>
<tr>
<td>(SMTS)</td>
<td>50.2 MWh in 2025/26, assuming no generation from Somerton PS ($1.84 million)</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Springvale</td>
<td>Not before 2026</td>
<td>0.1 MWh ($4,500)</td>
<td>Establish a new terminal station in the Dandenong area to off-load SVTS.</td>
<td>$7 million Demand reduction; Local generation</td>
<td></td>
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<tr>
<td>(SVTS)</td>
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<tr>
<td>Templestowe</td>
<td>Not before 2026</td>
<td>0.2 MWh ($6,700)</td>
<td>Install a fourth 150 MVA 220/66 kV transformer at TSTS.</td>
<td>$2 million Demand reduction; Local generation</td>
<td></td>
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<tr>
<td>(TSTS)</td>
<td></td>
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<tr>
<td>Thomastown</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>(TTS)</td>
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<tr>
<td>Terminal Station</td>
<td>Indicative timing for completion of preferred network solution (using 2016 VCR)</td>
<td>Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2016 VCR)</td>
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<td></td>
<td></td>
<td>10&lt;sup&gt;th&lt;/sup&gt; percentile demand forecast</td>
<td>50&lt;sup&gt;th&lt;/sup&gt; percentile demand forecast</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Terang (TGTS)</td>
<td>Not before 2022 (or 2019 based on AEMO’s previous VCR estimate escalated to 2016 dollars)</td>
<td>65.5 MWh in 2022 ($2.58 million)</td>
<td>46.5 MWh in 2022 ($1.83 million)</td>
<td>Install an additional 150 MVA 220/66 kV transformer. Powercor will continue to monitor peak demand at TGTS, and may initiate more detailed analysis of the value of customer reliability in the TGTS supply area, to determine the optimal timing of any augmentation or other corrective action. The timing of augmentation is also likely to be influenced by any further large scale wind farm developments in the area, which may drive the need for additional transformer capacity at TGTS to accommodate reverse power flows.</td>
<td>$1.8 million</td>
</tr>
<tr>
<td>Tyabb (TBTS)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon.</td>
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<tr>
<td>Wemen (WETS)</td>
<td>Not before 2026</td>
<td>11.1 MWh after load transfers to RCTS 66 ($0.49 million)</td>
<td>5.1 MWh after load transfers to RCTS 66 ($0.22 million)</td>
<td>Install an additional 70 MVA 235/66 kV transformer at WETS. Other lower cost options are being investigated to reduce the load at risk. There are proposals to connect large embedded generation to the 66 kV system in the area which may drive the need for additional transformer capacity at WETS to accommodate the reverse power flow expected at the station.</td>
<td>$1.4 million</td>
</tr>
<tr>
<td>West Melb 22 kV (WMTS 22 kV)</td>
<td>No augmentation of capacity is expected to be required within the ten year planning horizon. Under joint plans developed by CitiPower and AusNet Transmission Group, existing load supplied from WMTS 22 kV will be transferred to adjacent stations over the next six years, to enable the retirement of all of the existing WMTS 22 kV systems by the end of 2023.</td>
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<tr>
<td>West Melb 66 kV (WMTS 66 kV)</td>
<td>Following the transfer of approximately 140 MW of load to the new BTS in late 2016, there is sufficient capacity at WMTS 66 kV to supply the forecast 10th percentile and 50th percentile demand over the planning period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.</td>
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</tr>
<tr>
<td>Terminal Station</td>
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<tr>
<td>Wodonga (WOTS)</td>
<td>Not before 2026</td>
<td>2.7 MWh in 2016/17 ($0.11 million) excluding generation from Hume PS or any other source</td>
<td>0.2 MWh in 2016/17 ($9,800) excluding generation from Hume PS or any other source</td>
<td>At the 50th percentile demand forecast, the value of expected unserved energy is expected to decline from $9,800 in summer 2016/17 to a negligible level in summer 2025/26. In view of the low and declining level of expected unserved energy, there are currently no plans to implement a network solution within the ten year planning horizon.</td>
<td>N/A</td>
</tr>
</tbody>
</table>
1 INTRODUCTION AND BACKGROUND

1.1 Purpose of this report

This document sets out a joint report on transmission connection asset planning in Victoria, prepared by the five Victorian electricity Distribution Businesses (the DBs)\(^6\), in accordance with the requirements of clause 3.4 of the Victorian Electricity Distribution Code\(^7\) and clause 5.13.2 of the National Electricity Rules (the Rules)\(^8\).

It is emphasised that this report does not present detailed investment decision analyses. Rather, the report presents a high-level indication of the expected balance between capacity and demand at each terminal station\(^9\) over the forecast period.

Data presented in this report may indicate an emerging major constraint. Therefore, this report provides a means of identifying those terminal stations where further consultation and detailed analysis - in accordance with Regulatory Investment Test for Transmission - is required. This report also provides preliminary information on potential opportunities to prospective proponents of alternatives to network augmentations at terminal stations where remedial action may be required. Providing this information to the market should facilitate the efficient development of network and non-network solutions to best meet the needs of end-customers.

1.2 Victorian joint planning arrangements for transmission connection assets

For the purpose of this report, transmission connection assets are those parts of the transmission system which are dedicated to the connection of customers at a single point. In Victoria:

- as explained in further detail in section 1.3.1 below, the DBs have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the Victorian shared transmission network;\(^10\) and

- The Australian Energy Market Operator (AEMO) is responsible for planning and directing the augmentation of the shared transmission network.

It is noted that pursuant to Chapter 6A of the Rules, transmission connection assets are used to provide prescribed transmission services.

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\(^6\) The five DBs are: Jemena Electricity Networks (Vic) Ltd, CitiPower, Powercor Australia, United Energy, and AusNet Electricity Services Pty Ltd. AusNet Electricity Services is owned by AusNet Services, a diversified energy infrastructure business that also owns the Victorian electricity transmission system. Throughout this document “AusNet Transmission Group” refers to the transmission business of AusNet Services and “AusNet Electricity Services” refers to the electricity distribution business of AusNet Services.

\(^7\) Version 9, effective from December 2015.

\(^8\) Version 82 of the Rules was in force at the time of preparing this report.

\(^9\) A terminal station is a facility that connects a distribution network to the shared transmission network.

\(^10\) The shared transmission network is the main extra high voltage network that provides or potentially provides supply to more than a single point. This network includes all lines rated above 66 kV and main system tie transformers that operate at two or three voltage levels above 66 kV.
Figure 1 below illustrates the distinction between the shared transmission network and transmission connection assets.

Figure 1: Shared network and connection assets in a notional network

These planning arrangements are aimed at fostering efficient and coordinated development of transmission connection facilities and the downstream sub-transmission and distribution systems. The DBs are best placed to determine the optimum level of investment in, and configuration of, distribution system capacity and transmission connection capacity, having regard to:

- the needs and preferences of the end consumers of electricity;
- the relative costs and benefits associated with alternative distribution, sub-transmission and transmission connection development strategies, and alternative strategies that would deliver a level of supply reliability in accordance with consumers’ needs; and
- the incentives and penalties faced by the DBs in relation to the reliability of their distribution networks and the transmission connection facilities that they plan.

The transmission planning responsibilities of AEMO are set out in section 50C(1) of the National Electricity (South Australia) (National Electricity Law—Australian Energy Market Operator) Amendment Act 2009. Under that act, AEMO’s functions include:

“to plan, authorise, contract for, and direct, augmentation of the declared shared network”, where the declared shared network is defined as “the adoptive jurisdiction’s [in this case, Victoria’s] declared transmission system excluding any part of it that is a connection asset within the meaning of the Rules”.

In accordance with clause 5.14.1(a)(1) of the Rules, AEMO and the DBs undertake joint planning to ensure the efficient development of the shared transmission and distribution networks and the transmission connection facilities. To formalise these arrangements, the parties have agreed a Memorandum of Understanding (MoU).

The MoU sets out a framework for cooperation and liaison between AEMO and the DBs with regard to the joint planning of the shared network and connection assets in Victoria. In particular, the MoU sets out the approach to be applied by AEMO and the DBs in the assessment of options to address limitations in a distribution network where one of the options consists of investment in dual function assets or transmission investment, including connection assets and the shared transmission network. Under the MoU, the DBs and AEMO have agreed that subject to the thresholds set out in the Rules, joint
planning projects should be assessed by applying the Regulatory Investment Test for Transmission.

The DBs also liaise regularly with AusNet Transmission Group, the owner of the Victorian transmission system, to coordinate their transmission connection augmentation plans with AusNet Transmission Group’s asset renewal and replacement plans\(^\text{11}\).

### 1.3 DBs’ obligations as transmission connection planners

#### 1.3.1 Victorian regulatory instruments

Clause 14 of each DB’s Distribution Licence states:

“The **Licensee** is responsible for planning, and directing the augmentation of, **transmission connection assets** to assist it to fulfil its obligations [to offer connection services and supply to customers] under clause 6.”

The licence defines “transmission connection assets” as:

“those parts of an electricity transmission network which are dedicated to the connection of customers at a single point, including transformers, associated switchgear and plant and equipment.”

In accordance with their obligations under clause 3.1(b) of the Victorian Electricity Distribution Code, the DBs plan and direct the augmentation of the transmission connection assets in a way which minimises costs to customers taking into account distribution losses and transmission losses.

Clause 3.4 of the Victorian Electricity Distribution Code states:

“3.4.1 Together with each other distributor, a distributor must submit to the Commission a joint annual report called the ‘Transmission Connection Planning Report’ detailing how together all distributors plan to meet predicted demand for electricity supplied into their distribution networks from transmission connections over the following ten calendar years.

3.4.2 The report must include the following information:

- the historical and forecast demand from, and capacity of, each transmission connection;
- an assessment of the magnitude, probability and impact of loss of load for each transmission connection;
- each distributor’s planning standards;
- a description of feasible options for meeting forecast demand at each transmission connection including opportunities for embedded generation and demand management and information on land acquisition where the possible options are constrained by land access or use issues;”


• the availability of any contribution from each distributor including where feasible, an estimate of its size, which is available to embedded generators or customers to reduce forecast demand and defer or avoid augmentation of a transmission connection; and

• where a preferred option for meeting forecast demand has been identified, a description of that option, including its estimated cost, to a reasonable level of detail.

3.4.3 Each distributor must publish the Transmission Connection Planning Report on its website and, on request by a customer, provide the customer with a copy. The distributor may impose a charge (determined by reference to its Approved Statement of Charges) for providing a customer with a copy of the report.”

The Victorian Electricity Distribution Code was amended in March 2008 to include an additional provision (clause 3.1A) relating to the security of supply of the Melbourne CBD. This provision describes the circumstances in which the Melbourne CBD distributor (currently CitiPower) is required to prepare a CBD security of supply upgrade plan and also sets out the required scope of that plan. In particular, the CBD security of supply upgrade plan must:

• specify strengthened security of supply objectives for the Melbourne CBD and a date or dates by which those objectives must be met;

• specify the capital and other works proposed by the Melbourne CBD distributor in order to achieve the security of supply objectives for the Melbourne CBD that are specified in the plan; and

• meet the regulatory test (which is discussed in further detail in section 1.3.2 below).

This provision establishes a separate planning process that applies to the network supplying the Melbourne CBD only.

Given that this Transmission Connection Planning Report covers the whole of Victoria, it should acknowledge the existence of any CBD security of supply upgrade plan without unnecessarily duplicating that plan and its supporting analysis. Details of the CBD security of supply upgrade plan are available from CitiPower’s website at the following address:


The upgrade will protect Melbourne’s electricity supply from a prolonged blackout should there be major failures (i.e. the loss of two or more 66 kV subtransmission elements) within the electricity networks supplying the CBD and inner Melbourne area. The relevant transmission connection works (namely, the establishment of a new 66 kV source of supply at Brunswick Terminal Station) are a separate project, but are related to the CBD upgrade project. Following consultation by AEMO and CitiPower in 2011 on the options for addressing emerging constraints at three terminal stations currently servicing CitiPower’s distribution network in the Melbourne CBD and surrounding suburbs, a final report was published. The final report confirmed that:

• The preferred option is an upgrade of the existing Brunswick Terminal Station (BTS) to 66 kV supply with 220 kV and 66 kV indoor gas insulated switchgear.

• CitiPower and AEMO propose to implement the preferred option and expect that the additional capacity provided by the upgrade of BTS to a 66 kV terminal station will be available from late 2016.
Further details on the current status of the work at Brunswick Terminal Station is presented in section 5 of this report, in the risk assessment for that station.

1.3.2 National Electricity Rules

Part B of Chapter 5 of the Rules\(^\text{12}\) sets out provisions governing the planning and development of networks. These provisions require, amongst other things, Transmission and Distribution Network Service Providers to:

- prepare and publish annual planning reports;
- consult with interested parties on the possible options, including but not limited to demand side options, generation options and market network service options to address the projected network limitations; and
- undertake analysis of proposed network investments using the Regulatory Investment Test for Distribution (formerly the regulatory test) or the Regulatory Investment Test for Transmission, as appropriate.

As noted in section 1.2, the DBs and AEMO have agreed that subject to the thresholds set out in the Rules, joint planning projects involving transmission connection and distribution investment should be assessed by applying the Regulatory Investment Test for Transmission (RIT-T). This agreement is consistent with clauses 5.16.3(a)(2) and (6) of the Rules, which requires RIT-T proponents to apply the RIT-T to projects to augment distribution to transmission connection facilities where the estimated capital cost of the most expensive technically and economically feasible option to address the identified need exceeds $6 million\(^\text{13}\). It is noted that in circumstances where a transmission connection augmentation project is not a joint project, then the assessment of that project may be undertaken by the relevant DB(s) under the Regulatory Test for Distribution.

Clause 5.13.2 of the Rules requires Distribution Network Service Providers to publish a Distribution Annual Planning Report (DAPR). The DAPR must contain the information specified in schedule 5.8 of the Rules, unless that information is provided in accordance with jurisdictional electricity legislation.

Pursuant to clause 5.13.2(d) of the Rules, this Transmission Connection Planning Report presents the information on transmission connection planning required under schedule 5.8. The table below lists the relevant clause of schedule 5.8, and provides a cross reference to the section of this report where the required information is presented.

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\(^{12}\) Version 82 of the Rules was in force at the time of preparing this report.

Table 1A: Schedule 5.8 requirements addressed in this report

<table>
<thead>
<tr>
<th>Schedule 5.8 clause</th>
<th>Matters addressed</th>
<th>Where the information is presented in this report</th>
</tr>
</thead>
<tbody>
<tr>
<td>S5.8(b)(1)</td>
<td>A description of the forecasting methodology used</td>
<td>Section 2</td>
</tr>
<tr>
<td>S5.8(b)(2)(i), (iv), (v), (vi), (vii), (viii), and (ix)</td>
<td>Load forecasts and forecasts of capacity</td>
<td>Section 4, Section 5.6 and individual risk assessments for each terminal station</td>
</tr>
<tr>
<td>S5.8(b)(3)</td>
<td>Forecasts of future transmission-distribution connection points and any associated connection assets</td>
<td>The Executive Summary and individual risk assessments for each terminal station</td>
</tr>
<tr>
<td>S5.8(h)</td>
<td>The results of joint planning undertaken with Transmission Network Service Providers</td>
<td>Section 1.2 describes joint planning arrangements. The Executive Summary and individual risk assessments for each terminal station describe the results of joint planning.</td>
</tr>
<tr>
<td>S5.8(i)(1)</td>
<td>The results of joint planning undertaken with other Distribution Network Service Providers</td>
<td>As above</td>
</tr>
</tbody>
</table>

1.3.3 Reliability incentive scheme (s-factor) for the Distribution Businesses

Under the Service Target Performance Incentive Scheme (STPIS) and the Distribution Determination that applies from 1 January 2016 to 31 December 2020, each DB's revenue cap contains an s-factor which provides a revenue bonus when service performance is better than performance targets, and a penalty when service performance is worse than performance targets.

The operation of the s-factor relates to the distribution network, and therefore is not directly relevant to the reliability of the transmission system. However, under clause 3.3(a)(6) of the STPIS\(^\text{14}\), the DBs are exposed to financial penalties if load interruptions are caused by a failure of transmission connection assets where the interruptions are due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.

The financial incentives under these arrangements reinforce the DBs' responsibilities with respect to transmission connection planning, which are set out in the Distribution Licences and the Victorian Electricity Distribution Code as explained in section 1.3.1 above.

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\(^{14}\) AER, Electricity Distribution Network Service Providers - Service Target Performance Incentive Scheme, November 2009.
1.3.4 **AusNet Transmission Group’s role in delivering connection services**

The transmission connection assets\(^{15}\) are located within terminal stations which are owned, operated, and maintained by the TNSP (Transmission Network Service Provider), AusNet Transmission Group. Connection services are provided by AusNet Transmission Group in accordance with connection agreements between AusNet Transmission Group and each of the DBs. These agreements set out, amongst other things, the standard of connection services to be provided.

In addition, the revenue cap applying to AusNet Transmission Group contains a Service Target Performance Incentive Scheme (STPIS), in accordance with clause 6A.7.4 of the National Electricity Rules. The STPIS aims to balance the incentive for AusNet Transmission Group to minimise expenditure with the need to maintain and improve reliability for customers, by providing AusNet Transmission Group with a financial incentive to maintain or improve service levels.

1.4 **Matters to be addressed by proponents of non-network alternatives**

One of the purposes of this document is to provide information to proponents of non-network solutions (such as embedded generation or demand management) to emerging network constraints. As noted in further detail in Chapter 2 below, the DBs aim to develop their networks and the associated transmission connection assets in a manner that minimises total costs (or maximises net economic benefit). To this end, proponents of non-network solutions to the emerging network constraints identified in this report are encouraged to lodge expressions of interest with the relevant DB(s).

Proponents of non-network proposals should make initial contact with the relevant DB as soon as possible, to ensure that sufficient time is available to the DB to fully assess feasible network and non-network potential solutions, having regard to the lead times associated with the evaluation, planning and implementation of various options. Indicative timeframes for the network solutions are provided in the table in the Executive Summary.

To assist in the assessment of non-network solutions, proponents are invited to make a detailed submission to the relevant DB. This submission should be informed by earlier discussions with the relevant DB, and should include all of the following details about the proposal:

(a) proponent name and contact details;
(b) a detailed description of the proposal;
(c) electrical layout schematics;
(d) a firm nominated site;
(e) capacity in MW to be provided and number of units to be installed (if applicable);
(f) fault level contribution, load flows, and stability studies (if applicable);
(g) a commissioning date with contingency specified;
(h) availability and reliability performance benchmarks;

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\(^{15}\) With the exception of the connection assets at the Deer Park terminal station - expected to be commissioned by late 2017 - which will be owned, operated and maintained by TransGrid.
(i) network interface requirements (as agreed with the relevant DBs);

(j) the economic life of the proposal;

(k) banker / financier commitment;

(l) proposed operational and contractual arrangements that the proponent would be prepared to enter into with the relevant DBs;

(m) any special conditions to be included in a contract with the responsible DBs; and

(n) evidence of a planning application having been lodged, where appropriate.

All proposals must satisfy the requirements of any applicable Codes and Regulations.

In addition, as a general rule of thumb, any network reinforcement costs required to accommodate the non-network solution will typically be borne by the proponent(s) of the non-network project. Some non-network alternatives such as embedded generation may raise issues relating to fault level control. In particular, connection of additional embedded generators will result in an increase in fault levels. Therefore, fault level mitigation measures may be required because of the installation of embedded generation, in which case it would be equitable and efficient for the proponents of such projects to bear the costs of fault level mitigation works.

1.5 Implementing Transmission Connection Projects

In the absence of any commitment by interested parties to offer non-network solutions such as embedded generation or demand side management, the process to implement the preferred network solution will commence. A brief description of the implementation process for network solutions and the issues involved is presented below.

1.5.1 Land Acquisition

Network solutions may require land acquisition. The process of land acquisition for new terminal stations may be complex especially in metropolitan areas. Land acquisition issues and processes are beyond the scope of this document.

A limited number of vacant sites, currently owned by AusNet Transmission Group, have been reserved for possible future terminal station development in Victoria. DBs would need to seek AusNet Transmission Group’s consent to use any reserved land for transmission connection development.\(^\text{16}\)

The granting of a town planning permit on lands reserved for future terminal station development is by no means certain. In some municipalities, town planning approval may also be required for network augmentation on existing developed sites.

1.5.2 Connection Application to AEMO

Where a network solution requires new connection points with the shared transmission network to be established, a connection agreement with AEMO is required in accordance

with clause 5.3 (Establishing or Modifying Connection) of the National Electricity Rules. As noted in section 1.2, the 220 kV assets that form part of the Victorian shared transmission network fall under the planning jurisdiction of AEMO. Hence, issues associated with 220 kV switching arrangements and connection to the shared transmission system would be clarified with AEMO at the connection application stage. It is also noted that AEMO’s requirements regarding new connections must be finalised through a joint planning process involving AEMO and the relevant DBs. These activities can increase the lead time for delivery of projects by some months.

For augmentations to existing connection points, a connection application to AEMO may be required so that the effect on the shared transmission network, if any, can be taken into consideration. In some cases, AEMO and the relevant DBs may undertake a public consultation process in relation to the proposed development, in addition to the consultation processes that must be undertaken if the RIT-T applies. Similar to new connections, AEMO’s requirements regarding any augmentation of shared transmission network assets must be finalised through a joint planning process involving AEMO and the relevant DBs.


### 1.5.3 Connection Application to AusNet Transmission Group

It is most likely that establishment of new transmission connections, or augmentation of existing transmission connections will require interface to transmission assets owned by AusNet Transmission Group. In accordance with AusNet Transmission Group’s negotiating framework, an initial “Connection Inquiry” outlining the broad scope of service sought should be submitted to AusNet Transmission Group, followed by a “Connection Application” when the scope of the service has been accurately defined in consultation with AEMO and the relevant DB(s).

### 1.5.4 Town Planning Permit

For greenfield sites, DBs may need to engage the services of experienced town planning consultants, because very extensive planning requirements are usually laid down by local planning authorities. In most cases, the town planning permit application would need to be accompanied by extensive supporting documents such as:

- flora and fauna study;
- archaeological and cultural assessment;
- noise study;
- electromagnetic field (EMF) assessment;
- traffic analysis;
- layouts and elevation plans; and
- landscaping and fencing plans.

The choice of appropriate town planning consultants is very important, as they may need to provide expert witness statements to the Victorian Civil and Administrative Tribunal (VCAT) if objections to the transmission connection application are received. Due to the possibility of simultaneous shared network development by AEMO on the same site, it
may become necessary to invite AEMO to participate in the town planning process at the same time so that both the council and the public are made aware of the entire proposed development on the site.

For augmentation to existing transmission connection assets, the requirement for a town planning permit varies from council to council, and depends on the extent of the proposed work. AusNet Transmission Group is likely to be the initiator of the planning permit application for augmentation work at an existing terminal station.

1.5.5 Public Consultation Strategy

A key aspect of the public consultation strategy is the positive engagement of various stakeholders in the project from the initial stages of the development. The strategy may include:

- distribution of leaflets that provide information on the proposal in clear, concise, non-technical language to every nearby resident;
- presentations to the councillors of the local municipality and the local members of parliament; and
- public consultation such as display stands in local shopping centres to highlight the need for such a project and the resultant benefits to the community, and invitation of public comments on the proposal.

Feedback from stakeholders is then considered in the design of the transmission connection work to ensure the resultant project is acceptable to the local community.

1.5.6 Project Implementation

As noted in section 1.3.1, the DBs are required by the Victorian Electricity Distribution Code to augment the transmission connections in a way which minimises costs to customers taking account of distribution losses. This can be achieved by a variety of means, including competitive tendering and cost benchmarking.

Transmission connection augmentation works will be arranged by the relevant DBs in accordance with the requirements of any applicable guidelines in force.

1.5.7 Project lead times

The lead-time required for the implementation of connection asset augmentation projects depends on the number of interdependent activities involved in the project, and varies from between 3 to 5 years.

The critical path activities in the delivery of such projects include the following:

- Finalisation of any requirements for shared network augmentation due to planned connection asset augmentation works. These requirements are assessed through the joint planning process, which involves AEMO, AusNet Transmission Group and the DBs in Victoria.
• Procurement of a planning permit in relation to the proposed works. In order to obtain planning consent for proposed works, the statutory planning requirements of the local council(s) must be met, and community expectations must be addressed. For connection asset augmentations involving either major augmentations on an established site or the development of new terminal station(s) on new site(s), a period of at least 24 to 36 months is required for land planning and associated community issues to be resolved. The timely completion of this task requires effective coordination and cooperation between AEMO, AusNet Transmission Group and the DBs through the joint planning process in Victoria.

• After completing the above two tasks successfully, the next important tasks are:
  - finalisation of the scope of works;
  - preparation of cost estimates (including invitation to tender if the project is contestable); and
  - finalisation and execution of all contracts and agreements between distribution and transmission network service providers after obtaining all the necessary internal business approvals.

Once the project contracts are signed, the next important task is the delivery of the project itself, including installation and commissioning of the assets into service. AusNet Transmission Group’s recent experience indicates that the lead-time required for the delivery of a connection asset augmentation involving power transformers is between 18 and 24 months. In some cases, issues identified during testing of completed units have resulted in further delays. In view of this, for planning purposes it is assumed that approximately 24 months would be required to procure, install and commission power transformers from the time that a commercial contract is signed between the parties to complete the project works.
1.6 Overview of Transmission Connection Planning Process

The flow chart below provides a summary of the transmission connection planning and augmentation process under the regulatory framework which presently applies to the Victorian DBs.

**PROCESS FLOW CHART: TRANSMISSION CONNECTION PLANNING**
2 PLANNING STANDARDS

2.1 Planning standard applying to transmission connection assets

Clause 3.4.2(c) of the Victorian Electricity Distribution Code requires this report to set out the planning standards applying to transmission connection assets. The planning standard applied by the DBs is the Regulatory Investment Test for Transmission (RIT-T), the purpose of which is set out in clause 5.16.1(b) as follows:

“To identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.”

Clause 5.10.2 of the Rules defines “reliability corrective action” as follows:

“Investment by a Transmission Network Service Provider or a Distribution Network Service Provider in respect of its transmission network or distribution network for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options.”

The terms “applicable regulatory instruments” is defined in the Rules as follows:

“All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the Rules) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.”

Applicable regulatory instruments in Victoria include:

- the Electricity Industry Act 2000 (EI Act);
- all regulations made and licences (Licences) issued under the EI Act;
- the Essential Services Commission Act 2001 (ESCV Act);
- all regulations and determinations made under the ESCV Act;
- all regulatory instruments applicable under the Licences; and
- the Tariff Order made under section 158A(1) of the Electricity Industry Act 1993 and continued in effect by clause 6(1) of Schedule 4 to the Electricity Industry (Residual Provisions) Act 1993, as amended or varied in accordance with section 14 of the Electricity Industry Act.

Further background information on the planning standard applying to transmission connection assets, and the probabilistic planning approach applied by the DBs for the purpose of evaluating net economic benefits is set out in sections 2.2 to 2.5 below.
2.2 Overall objective of transmission connection planning

The planning standards and criteria applied in network development are a significant determinant of network-related costs. Costs associated with transmission connection facilities can be considered to be comprised of two parts:

- the direct cost of the service (as reflected in network charges and the costs of losses); and
- indirect costs borne by customers as a consequence of supply interruptions caused by network faults and/or insufficient network capacity.

The DBs aim to develop transmission connection facilities in an efficient manner that minimises the total (direct plus indirect) life-cycle cost of network services. This basic concept is illustrated in Figure 2 below.

In accordance with the requirements of the RIT-T, the DBs' transmission connection investment decisions aim to maximise the net present value to the market as a whole, having regard to the costs and benefits of non-network alternatives to augmentation. Such alternatives include, but are not necessarily limited to, demand-side management and embedded generation.
2.3 Overall approach to transmission planning and investment evaluation

In Victoria, pursuant to section 50C of the National Electricity Law, AEMO applies a probabilistic approach\(^\text{17}\) to planning the shared transmission network\(^\text{18}\).

Under the probabilistic approach, deterministic standards (such as N-1) are not applied. Instead, simulation studies are undertaken to assess the amount of energy that would not be supplied if an element of the network is out of service. The application of this approach can lead to the deferral of transmission capital works that might otherwise proceed if a deterministic standard were strictly applied. This is because:

- in a network planned in accordance with the probabilistic approach, there may be conditions under which all the load cannot be supplied with a network element out of service (hence the N-1 standard is not met); however
- under these conditions, the value of the energy that is expected to be not supplied is not high enough to justify additional investment, taking into account the probability of a forced outage of a particular element of the transmission network.

However, implicit in the use of a probabilistic approach is acceptance of the risk that there may be circumstances (such as the loss of a transformer during a high demand period) when the available terminal station capacity will be insufficient to meet actual demand, and significant load shedding could be required.

In Victoria, the jurisdiction has not set deterministic standards applying to transmission connection assets. However, clause 5.2 of the Victorian Electricity Distribution Code sets out the following requirements relating to reliability of supply:

“A distributor must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.”

In light of these considerations and the requirements of the RIT-T, the DBs apply probabilistic planning and economic investment decision analysis to transmission connection assets, subject to meeting the technical and other standards set out in the Rules and other applicable regulatory instruments including the Victorian Electricity Distribution Code.

2.4 Valuing supply reliability from the customers’ perspective

In order to determine the economically optimal level and configuration of connection capacity (and hence to deliver a level of supply reliability that will meet customers’ reasonable expectations), it is necessary to place a value on supply reliability from the perspective of customers.


\(^{18}\) As explained in section 1, the “shared transmission network” is the Victorian transmission system, excluding the transmission facilities that connect the distribution networks (and the generators) to the high voltage network. The distribution businesses are responsible for the planning and development of the transmission facilities that connect their distribution networks to the shared transmission network. These arrangements are set out in the distribution licences issued by the ESC.
Estimating the marginal value to customers of reliability is inherently difficult, and ultimately requires the application of some judgement. Nonetheless, there is information available (principally, surveys designed to estimate the costs faced by customers from electricity supply interruptions) that provides a guide to the likely value.

In September 2014, AEMO published its final report on its 2013–2014 review of the Value of Customer Reliability (VCR). AEMO conducted the review at the request of the former Standing Council on Energy and Resources (SCER), now the Council of Australian Governments' (COAG) Energy Council. AEMO’s final report explained that:\(^\text{19}\):

“The VCR represents, in dollar terms, the estimated aggregated value that customers place on the reliable supply of electricity. The actual value will vary by the type of customer and the characteristics of the outages being considered. The VCR at different points on the grid would then vary based on the mix of customer types at that point. As customers cannot directly specify the value they place on reliability, the VCR plays an important role in determining the efficient level of investment in, and efficient operation and use of, electricity services required by customers in the National Electricity Market (NEM).”

AEMO’s final report summarised its findings as follows:\(^\text{20}\):

“AEMO’s assessment of the survey findings includes the following:

1. Residential VCR values are similar across all NEM states.
2. The most important outage characteristics affecting residential VCR values are length of outage and whether the outage occurred at the time of the NEM daily peak.
3. Residential VCR values have not substantially changed since the 2007–08 values. However, survey feedback indicates that residential customers are concerned about the rise in electricity prices since 2007–08, which has resulted in an increased customer focus on implementing energy efficiency measures.
4. Business VCR values on average continue to be higher than the residential values, consistent with other Australian and international studies.
5. Business VCR values for the commercial and agricultural sectors are notably lower than the 2007–08 values.
6. Drivers include increased electricity costs since 2007–08 and the implementation of energy efficiency savings by businesses in these sectors.
7. Larger businesses tend to have a lower VCR value than smaller businesses, reflecting the likelihood that larger businesses are better equipped to mitigate against the impact of power outages.
8. The survey indicates the majority of residential and business customers are satisfied with their current level of reliability and consider it to be of a high standard.
9. The VCR values are broadly consistent with international and Australian VCR studies, where a similar survey methodology and approach has been used.”


\(^{20}\) Ibid, page 1.
In December 2014, AEMO published its final Application Guide on the VCR\(^\text{21}\). Section 5 of the Application Guide explains that:

- It is AEMO’s intention to conduct surveys every 5 years to estimate the VCR.
- To help maintain the currency of VCR estimates over time, AEMO considers it is appropriate to index VCR values between surveys using the Consumer Price Index (CPI).

Table 1 below shows the 2016 VCR estimates obtained by applying the annual indexation adjustment (set out in section 5.2 of the VCR Application Guide) to AEMO’s sector and composite VCR estimates for 2014 (as set out in AEMO’s September 2014 VCR Review Final Report).

<table>
<thead>
<tr>
<th>Sector</th>
<th>VCR for 2016 ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential (Victoria)</td>
<td>25.42</td>
</tr>
<tr>
<td>Commercial (NEM)</td>
<td>45.91</td>
</tr>
<tr>
<td>Agricultural (NEM)</td>
<td>48.94</td>
</tr>
<tr>
<td>Industrial (NEM)</td>
<td>45.23(^\text{22})</td>
</tr>
<tr>
<td>Composite- all sectors</td>
<td>40.55</td>
</tr>
</tbody>
</table>

The DBs note that the indexation adjustment results in a 1.3% increase in the VCR from 2015 to 2016.

As noted in last year’s Transmission Connection Planning Report, AEMO’s 2014 VCR survey entailed significant reductions in the VCR estimates for the commercial and agricultural sectors compared to the results of the 2007-08 VCR study, which was conducted on behalf of VENCorp (AEMO’s predecessor) by CRA International. This led to a reduction in AEMO’s estimate of the composite VCR from $63 per kWh in 2013 to $39.50 per kWh in 2014.

From a planning perspective, it is appropriate for the DBs to have regard to the most recent VCR estimates. It is also important to recognise, however, that all methods for estimating VCR are prone to error and uncertainty, as illustrated by the wide differences between:

- AEMO’s previous VCR estimate of approximately $67 per kWh (expressed in 2016 dollars), which was based on the 2007-08 VENCorp study\(^\text{23}\);

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\(^{22}\) Excludes industrial customers that are directly connected to the transmission network.
• Oakley Greenwood’s 2012 estimate of the New South Wales VCR\textsuperscript{24}, of approximately $102 per kWh (expressed in 2016 prices); and

• AEMO’s 2016 Victorian VCR estimate of $40.55 per kWh.

The wide range of VCR estimates produced by these three studies is likely to reflect estimation errors and methodological differences between the studies, rather than changes in the actual value that customers place on reliability\textsuperscript{25}. Moreover, the magnitude of the recent reduction in AEMO’s VCR estimates raises concerns that the investment decisions signalled by applying the most recent VCR estimate may fail to meet customers’ reasonable expectations of supply reliability.

In view of these considerations, the risk assessments presented in this report test the investment evaluation against AEMO’s previous VCR estimate. Where application of the earlier VCR estimate produces a materially different investment signal over the next five years (and hence different reliability outcomes for customers) compared to the updated estimate, the DBs will undertake further analysis. Customer consultation may also assist in determining how best to meet customers’ reasonable expectations of supply reliability in accordance with clause 5.2 of the Victorian Electricity Distribution Code.

In applying the VCR, it is also important to recognise that VCR is a composite (or weighted average) measure of customer interruption costs:

• for a wide range of different customers; and

• across a wide range of supply interruption attributes including time of day, duration, frequency, and season.

The range of sector VCR values has potentially significant implications for transmission connection investment decisions, especially where the composition of the load supplied from a constrained terminal station is dominated by a particular sector. These considerations suggest there is a case for applying sector-specific VCR values in transmission connection investment analysis, where a constraint affects a readily identifiable group of consumers. It may also be appropriate to calibrate the VCR estimate to take into account the outage scenario, as noted by AEMO\textsuperscript{26}:

“[…] customer class VCRs are aggregated values derived by probability-weighting the VCR of 24 outage scenarios. However, in some cases network planning may only be concerned with specific outage scenarios (i.e. ones occurring during peak times). Then, it may be appropriate to re-weight the outage probabilities to create an aggregate customer class VCR that better reflects the outage scenarios considered. For example, where network planning identifies that an outage in peak conditions results in a loss of supply to a connection point, customer class VCRs are re-weighted by removing off-peak outage scenarios and changing peak demand scenario probabilities.

For example, consider a 22 kV underground feeder which serves residential customers only. Based on historical data, outages on this part of the network mainly occur during peak demand periods, with few occurring at other times. Further, most outages are

\textsuperscript{23} See section 2.4 of the Victorian DB’s 2013 Transmission Connection Planning Report.

\textsuperscript{24} AEMO, Value of Customer Reliability Review Appendices, Appendix G, September 2014.

\textsuperscript{25} A further source of differences in the composite VCR estimates is the estimated composition of load by sector.

restored within three hours. Here it may be appropriate to re-weight the VCR based on revised outage probabilities that reflect actual outage times and durations.

A re-weighted residential VCR for a similar scenario may be in the range of $32/kWh, which is about 30% higher than the aggregate Victoria residential VCR value.”

In general, this report provides details of the VCR values used for each terminal station, based on the composition of station load by sector, and the sector VCR estimates provided by AEMO and set out in Table 1 above. However, in accordance with the approach outlined in AEMO’s VCR Application Guide, where it is appropriate to apply a VCR to reflect a particular outage scenario, this approach is noted in the relevant risk assessment for each terminal station.

2.5 Application of the probabilistic approach to transmission connection planning

The probabilistic planning approach involves estimating the probability of a plant outage occurring, and weighting the costs of such an occurrence by its probability to assess:

- the expected cost that will be incurred if no action is taken to address an emerging constraint,\(^\text{27}\) and therefore
- whether it is economic to augment terminal station capacity to reduce expected supply interruptions.

The quantity and value of energy at risk is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints; and
- the cost of having some exposure to loading levels beyond the network’s capability.

In other words, recognising that very high loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under conditions of very high loading. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower volumes of unserved energy.

This approach provides a reasonable estimate of the expected net present value to consumers of terminal station augmentation for planning purposes. However, implicit in its use is acceptance of the risk that there may be circumstances (such as the loss of a transformer during a high demand period) when the available terminal station capacity will be insufficient to meet actual demand, and significant load shedding could be required. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard to:

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes;
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand,

\(^\text{27}\) The energy that would not be supplied in the event of an interruption is valued in accordance with the approach outlined in Section 2.4 above.
and catastrophic plant failure leading to increased safety risk, increased risk of property damage, and/or extended periods of plant non-availability;

- the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk; and

- the Victorian DBs’ obligation (under clause 5.2 of the Victorian Electricity Distribution Code) to use best endeavours to meet, among other things, reasonable customer expectations of reliability of supply.
3 CURRENT AND EMERGING PLANNING CONSIDERATIONS

The purpose of this chapter is to outline current electricity market developments or recent events in Victoria that may have a bearing on the DBs’ transmission connection planning activities. While such matters are considered routinely in preparing this report, the DBs recognise that stakeholders may value a short discussion of recent developments and how they relate to transmission connection planning.

1. Electricity market changes, and the emergence of embedded generation

Electricity transmission and distribution networks play an essential role in the delivery of electricity to end consumers. In recent years, the electricity market has changed significantly. These changes follow a long period of a relatively stable energy market characterised by steady growth in consumption and demand.

The changes include:

- a decline in market-wide electricity consumption from historically high levels, with minimal growth in consumption expected over the medium term\textsuperscript{28};
- increased variability in peak demand growth rates across regions, with some regions exhibiting comparatively strong demand growth, and other regions exhibiting very low or in some cases negative demand growth;
- increased prominence of distributed and renewable generation at both the consumer end of the supply chain (for example, residential solar panels) and in the wholesale generation market (for example, wind and solar farms); and
- the development of other technologies that enable consumers to generate and store their own electricity.

The significant increase in connection applications for low carbon generation in recent years has given rise to the need for the DBs’ transmission connection planning activities to include:

- analysis and management of voltage compliance issues associated with the connection of new low carbon generation to the distribution network;
- assessing the impacts of possible reverse power flows through transmission connection assets;
- specifying connection requirements and operating the distribution system so as to ensure that generating stations remain stable and connected during system disturbances; and
- determining the design specifications for new transformers so that any new plant installed enables the efficient mitigation of emerging voltage management issues.

\textsuperscript{28} AEMO’s 2016 National Electricity Forecast Report (page 3) states: “Consumption of grid-supplied electricity is forecast to remain flat for the next 20 years, despite projected 30% growth in population and average growth in the Australian economy.”
Our planning also takes account of the specific peak demand forecasts across each region in assessing the need for transmission connection augmentation at each terminal station.

The DBs will continue to monitor the changing role of the network and the increasing contribution from distributed generation, and will continue to explore the most efficient options including network and non-network solutions. Our aim is to ensure that the network continues to provide cost effective and reliable services that meet the needs of all users, including low carbon generators.

2. **Management of system fault levels**

As noted above, there have been significant changes in the mix of generation in the Victorian power system, and across the National Electricity Market over recent years. The increasing proportion of non-synchronous generation (both large-scale and distributed) creates a number of operational challenges. One such challenge is the management of changing fault levels across the power system.

Further changes in the generation mix in Victoria are expected in the immediate future and over the medium term, with:

- the planned closure of Hazelwood Power Station in March 2017;
- further increases in the connection of new low carbon generation to the network; and
- the possible development of increased interconnector capacity.

These developments will drive further changes in fault levels across the system. The DBs are acutely aware of the need to closely monitor changes in fault levels, and to ensure that transmission connection plans take account of present and likely future changes in fault levels.

3. **Managing the risk of transformer failure**

Over the past 18 months, three transmission connection transformers have failed unexpectedly. In each of these cases, adverse impacts on customers have been mitigated through the installation of spare transformers that AusNet Transmission Group holds for this purpose.

The DBs and AusNet Transmission Group have commenced a joint study to review the current arrangements for spare transformers, and to determine the optimal number and type of spares that should be held. Further information on spare transformers is provided in section 5.5.

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30 In an electric power system, a fault or fault current is any abnormal electric current. For example, a short circuit is a fault in which current bypasses the normal load. In power systems, protective devices detect fault conditions and operate circuit breakers to protect an electrical circuit from damage caused by overload or short circuit. In order for a circuit breaker to operate safely and reliably, the current that flows in the event of a fault must be within the rating or short-circuit limits of the circuit breaker and other terminal station equipment.
4. Maintaining security of supply during major terminal station refurbishments

Over recent years, AusNet Transmission Group has been undertaking an asset refurbishment program. As noted in more detail in the risk assessments in this report, a number of terminal station refurbishments have been completed, while others are planned or in progress.


The larger terminal station refurbishments require careful outage and construction sequencing to ensure security of supply to the distribution networks is not compromised. Security of supply risks can also be mitigated efficiently by planning some temporary or permanent network reconfigurations of the distribution networks supplied from the terminal station.

As AusNet Transmission Group’s asset renewal program continues to progress, the DBs will continue to work collaboratively to manage the reliability risks during construction and minimise total costs to customers.
4 HISTORIC AND FORECAST DEMAND

In accordance with the requirements of clause 3.4.2 of the Victorian Electricity Distribution Code, data showing the historical and forecast demand from, and capacity of, each transmission connection are presented for each terminal station in the individual risk assessments that form part of this Transmission Connection Planning Report.

The demand forecasts used in the preparation of this report are referred to as the Victorian Terminal Station Demand Forecasts (TSDF). The TSDF sets out transmission connection point demand forecasts as provided by Victorian participants, being the Victorian DBs and directly connected customers. A spreadsheet setting out these forecasts for the period from 2016/17 to 2026/27 has been published by the Victorian DBs alongside this Transmission Connection Planning Report.


The 2014 and 2015 Transmission Connection Planning Reports noted that there were differences between the demand forecasts in the DBs’ TSDF and AEMO’s Victorian connection point forecasts in those years. Since 2014, the DBs’ and AEMO’s aggregate forecasts have converged, however, differences remain at some terminal stations.

In last year’s Transmission Connection Planning Report, the DBs noted that the reasons for the differences between AEMO’s forecasts and the TSDF appeared to relate to:

- problems with AEMO’s historical data sets, arising from misallocated State-wide demand forecasts to individual terminal stations or inappropriate treatment of load transfers;
- the magnitude of post-model adjustments undertaken by AEMO to allow for rooftop PV and energy efficiency impacts in particular;
- weather normalisation processes; and
- the relationship between AEMO’s energy and demand forecasting models.

Although AEMO has reviewed and refined its forecasting methodologies over the past 12 months, the DBs consider that at least some of these factors persist, and continue to give rise to differences between AEMO’s and the DBs’ connection point forecasts.

To address these issues, AEMO is arranging a series of joint meetings with the DBs to allow all parties to discuss their demand forecasting methods, and to better understand the differences between the forecasts they produce. The DBs welcome this initiative, and will continue to work with AEMO to improve demand forecasting methodologies, and to understand and address the differences between the forecasts produced by AEMO and the DBs.
The DBs consider it appropriate to continue to adopt the TSDF forecasts for the purpose of preparing this Transmission Connection Planning Report. It is noted that the TSDF forecasts have been applied in all previous Transmission Connection Planning Reports.
5 RISK ASSESSMENT AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS

5.1 Preamble

This section presents an overview of the magnitude, probability and impact of loss of load at each transmission connection, in accordance with the requirements of clause 3.4.2(b) of the Victorian Electricity Distribution Code.

The assessment presented is not a detailed planning analysis, but a high-level description of the expected balance between capacity and demand over the forecast period. Data presented in this high-level analysis may indicate an emerging major constraint. Therefore, this high-level assessment provides a means of identifying those terminal stations where further detailed analysis of risks and options for remedial action, in accordance with the RIT-T, is required.

It is emphasised that this high-level analysis focuses on risks to supply reliability that relate to the capacity and reliability of transformers only. There are typically risks to supply reliability associated with the performance and capacity of smaller plant items. However, these smaller items involve relatively low capital expenditure, the deferral of which is unlikely to entail a sufficiently high avoided cost to justify the employment of non-network alternatives.

In addition, capital expenditure is required from time to time to address fault level issues. This expenditure is driven chiefly by mandatory health and safety standards, and does not relate to terminal station capacity, per se. Fault level issues are therefore not within the scope of this report, however, the analysis of feasible and preferred options for increasing capacity will, where appropriate have due regard to issues relating to fault level control.\(^{31}\)

The following key data are presented in this section for each Terminal Station:

- **Energy at risk:** For a given demand forecast, this is the amount of energy that would not be supplied from a terminal station if a major outage of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.6 months (as discussed in section 5.4 below), and no other mitigation action is taken. This statistic provides an indication of the magnitude of loss of load that would arise in the unlikely event of a major outage of a transformer.

- **Expected unserved energy:** For a given demand forecast, this is the energy at risk weighted by the probability of a major outage of a transformer. A load duration curve is used to estimate the unserved energy in each hour of the year for a major transformer outage. The estimated unserved energy for each hour is then multiplied by the probability of the outage occurring in any hour of the year. The total expected unserved energy in a year is obtained by summing the probability-weighted estimates of unserved energy for each hour of the year. This statistic provides an indication of the amount of energy, on average, that will not be supplied in a year, taking into

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31 Some non-network alternatives such as embedded generation may raise issues relating to fault level control. A further discussion of this issue is set out in Section 1.4 of this report.

32 The term “major outage” refers to an outage that has a mean duration of 2.6 months, typically due to a significant failure within the transformer. The actual duration of an individual major outage may vary from under 1 month up to 9 months. Further details are provided in section 5.4 below.
account the very low probability that one transformer at the station will not be available for 2.6 months because of a major outage.

Risk assessments for each individual terminal station provide estimates of energy at risk and expected unserved energy based on the 50\textsuperscript{th} percentile and 10\textsuperscript{th} percentile demand forecasts set out in Section 4. Consideration of energy at risk and expected unserved energy at these two demand forecast levels provides:

- an indication of the sensitivity of these two parameters to temperature variation over the peak period; and
- an indication of the level of exposure to supply interruption costs at higher demand conditions (namely, 10\textsuperscript{th} percentile levels).

As already noted, this information provides an aid to identifying the likely timing of economically-justified augmentations or other actions. However, the precise timing of augmentation or any other non-network solutions aimed at alleviating emerging constraints will be a matter for more detailed analysis prepared in accordance with the RIT-T requirements.

In interpreting the information set out in this report, it is important to recognise that in the case of a Summer peaking station, the 50\textsuperscript{th} percentile demand forecast relates to a maximum average temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50\% probability of being higher than the 50\textsuperscript{th} percentile demand forecast.\(^{33}\)

5.2 Interpreting “energy at risk”

As noted above, “energy at risk” is an estimate of the amount of energy that would not be supplied if one transformer was out of service due to a major failure during the critical loading season(s), for a given demand forecast.

The capability of a terminal station with one transformer out of service is referred to as its “N minus 1” rating. The capability of the station with all transformers in service is referred to as its “N” rating. The relationship between the N and N-1 ratings of a station and the energy at risk is depicted in the diagram below.

\(^{33}\) Conversely, there is also a 50\% chance that actual demand will be lower than the forecast in any one year.
5.3 Assessing the costs of transformer outages

As noted in Section 5.1, for a given demand forecast:

- “energy at risk” denotes the amount of energy that would not be supplied from a terminal station if a major outage of a single transformer occurs at that station in that particular year, and no other mitigation action is taken; and
- “expected unserved energy” is the energy at risk weighted by the probability of a major outage of a single transformer.

In estimating the expected cost of connection plant outages, this report considers the first order contingency condition (“N minus 1”) only. It is recognised that in the case of terminal stations that consist of two transformers, there is a significant amount of energy at risk if both transformers are out of service at the same time, due to a major outage. Some interested parties have therefore suggested that the analyses presented in this report should be expanded to include consideration of the costs of major outages under N-1 (first order contingency) and N-2 (second order contingency) conditions.

The DBs have carefully considered these suggestions, and concluded that it is not necessary for the analyses presented in this report to be extended to include consideration of second order contingency conditions. The principal reason for this is that the value of expected unserved energy associated with second order contingencies would be unlikely to be sufficiently high to justify the advancement of any major augmentation, compared to the augmentation timing that is economically justified by an analysis that is limited to considering first order contingencies. The Appendix contains a detailed example which illustrates this point.

However, in undertaking a detailed economic evaluation of network investment in accordance with the RIT-T, the DBs agree that the quantity and value of energy at risk associated with higher order contingencies should be considered. As noted above, these higher order contingencies are unlikely to affect the indicative timing of the required investment, which is the primary focus of this report.
5.4 Base reliability statistics for transmission plant

Estimates of the expected unserved energy at each terminal station must be based on the expected reliability performance of the relevant transformers. The basic reliability data for terminal station transformers has been established and agreed with the asset owner, AusNet Transmission Group. The base data focuses on:

- the availability of the connection point main transformers; and
- the probability of a major problem forcing these plant items out of service for an average period of 2.6 months. This does not include minor faults that would result in a transformer being unavailable for a short period of time (ranging from a few hours up to no more than two days).

The basic reliability data adopted for the purpose of producing this report is summarised in the following table. It is derived from the statistical data collected in a survey carried out in 1995 for the Australian CIGRE Panel 12 on Transformer Reliability, with support from AusNet Transmission Group, the owner of the connection assets.

<table>
<thead>
<tr>
<th>Major plant item: Terminal station transformer</th>
<th>Interpretation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Major outage rate for transformer</td>
<td>1.0% per annum</td>
</tr>
<tr>
<td>Weighted average of major outage duration</td>
<td>2.6 months</td>
</tr>
<tr>
<td>Expected transformer unavailability due to a major outage per transformer-year</td>
<td>0.01 x 2.6/12 = 0.217% approximately</td>
</tr>
</tbody>
</table>

In September 2016, AusNet Services’ Principal Engineer, Strategic Network Planning confirmed that the transformer outage rate data and the average transformer repair time assumptions adopted in this report are reasonable, for the purpose of preparing the transmission connection asset risk assessments.

Further details regarding the estimation of the weighted average duration of “major outages” are provided in the Appendix. The Appendix also sets out an example demonstrating the calculation of the “Expected Transformer Unavailability” for a terminal station with two transformers, using the basic reliability data contained in this section.

---

34 AusNet Transmission Group uses asset condition based failure risk information for asset replacement decisions. Joint planning is undertaken with the DBs to coordinate terminal station augmentation works with AusNet Transmission Group’s replacement plans.
5.5 Availability of spare transformers

In November 2016, AusNet Transmission Group’s Principal Engineer, Strategic Network Planning advised that:

- The two 220/66 kV metropolitan spare transformers will not be available for Summer 2016/17 as they are being utilised at Ringwood and Fishermans Bend terminal stations following transformer failures at these two connection stations.

- The country spare transformer will not be available for the start of summer 2016/17 as it has been used as a permanent replacement for the Ballarat 220/66 kV transformer that failed in July 2015.

- Following these events, AusNet Transmission Group has implemented the following actions:
  - A “universal” spare transformer (that is, one that may be used in either the country or metropolitan areas) is being procured, which will be generally suitable for use at any 220/66 kV station. However, it may not share load optimally due to differences in transformer impedances as the design needs to be compatible with both country and metropolitan connection stations. Consequently, the universal spare transformer may provide reduced capacity compared to the original transformer. The universal spare transformer is expected to be available for use by late 2017.
  - A new metropolitan spare transformer is being procured, and should be available for use by late 2017.
  - A new country spare transformer is also being procured and delivery is expected in January 2017. The transformer will be suitable for installation at any 220/66 kV country terminal station. Prior to the delivery of the new country spare transformer, a recently replaced 165 MVA 220/66 kV transformer at Morwell will act as a temporary country spare.
  - The new country spare and the universal spare transformers will have rated 22 kV windings, so they will be capable of supplying 22 kV load as well as 66 kV load.
  - Spare transformers held by AusNet Transmission Group may be used to support essential maintenance activities including refurbishment programs. Any transformer used in this way would no longer be available to replace a failed transformer.
  - AusNet Transmission Group will aim to install a spare transformer to replace a unit that is subject to a long term outage within one calendar month. However, it is not possible to provide a guaranteed time for installation of the temporary replacement, because the particular circumstances of each transformer failure will determine the replacement timeframe.
  - There is a small number of stations for which a stock of spare transformers is not held. These stations are the metropolitan 220/22 kV connection stations (being Ringwood, Brunswick, Richmond, West Melbourne and Brooklyn) and Wodonga 330/66/22 kV Terminal Station. For the metropolitan stations, an in-service ‘hot’ spare is provided by one of the 220/22 kV transformers at Brunswick. The
timeframes for deploying the ‘hot’ spare are likely to exceed one calendar month. In
the case of Wodonga 330/66/22 kV Terminal Station, the energy at risk does not
warrant the procurement of a dedicated spare transformer.

The DBs and the asset owner (AusNet Transmission Group) have initiated a joint study to
review the level of transformer spares holdings, to verify whether the planned future
holdings are optimal36. The assumptions and inputs used to prepare the risk
assessments in this report will also be reviewed in light of the study’s findings and any
proposed change in the number of spare transformers.

The risk analysis in this report assumes that a spare transformer will not be available if an
existing transformer fails. The DBs regard this assumption as appropriately conservative,
as there can be no guarantee that a spare will be available. As explained in section 5.4,
the risk analysis assumes that the average outage duration is 2.6 months, which is the
estimated repair time for a major failure of a transformer.

5.6 Treatment of Load Transfer Capability

For many terminal stations there is some capability to transfer load from one station to
adjacent ones using the distribution network. The amount of load that can be transferred
varies from minimal amounts at most country terminal stations to significant amounts at
some urban terminal stations. Some load transfers are able to be made at 66 kV and/or
22 kV and lower voltage levels.

In the event of a transformer failure at a terminal station, load could be transferred away
(where short-term transfer capability is available) and this would reduce the unserved
energy and the impact of an outage. The risk assessments presented in this planning
report assume normal network operating conditions, and therefore they show estimates of
load at risk and expected unserved energy before any potential short-term load transfers.
The reasons for this approach are:

- There is no guarantee that capacity will be available at an adjacent terminal station to
  accept load transfers, due to uncertainty of the availability of transformation capacity
  at that station.

- The capability of the distribution network to affect load transfers is always changing.
  It will vary depending on network loading conditions and is usually at a minimum
  during peak demand times. The transfer capability can also be adversely affected by
  any abnormal configurations which are implemented from time to time to manage
  power flows across the distribution network.

- Implementing short term transfers places the network in a suboptimal operating
  condition, thereby increasing operational risks. As already noted, the network
  planning studies presented in this report evaluate load at risk for a single contingency
  under otherwise normal network operating conditions. This approach accords with
  sound network planning practices.

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36 As noted in section 1.3.4, the connection assets at Deer Park Terminal Station (DPTS) - expected to
be commissioned by late 2017 - will be owned, operated and maintained by TransGrid. Powercor
has recently requested TransGrid to provide a plan on the provision of a spare transformer for that
station. It is understood that TransGrid is currently investigating options for the provision of a spare
transformer for DPTS.
The one exception to this approach is Wemen Terminal Station, which is the only single transformer station considered in this report. Wemen was planned on the basis that some load transfer capability at 66 kV would be available to Red Cliffs Terminal Station (RCTS 66) in the event of a transformer outage at Wemen. Accordingly, the risk assessment for Wemen takes into account the load forecasts for RCTS 66 and an assessment of the post-contingent load transfer capability.

For the other stations where there is short-term load transfer capability available, the relevant risk assessment identifies load transfer as an operational solution to mitigate the severity of a major outage.

5.7 Detailed risk assessments and options for alleviation of constraints, by terminal station

Set out on the following pages are the detailed risk assessments and a description of the options available for alleviation of constraints, for each individual terminal station. The assessments, by station, are set out in alphabetical order. For each station, the network augmentation requirements (if any) and the estimated annual costs of the augmentation works are identified. This cost estimate provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation.

However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation. For example, a non-network solution that defers a network augmentation from 2020 to 2023 is less valuable today than one which defers a network augmentation from, say, 2017 to 2020. These issues should be considered by proponents of non-network solutions in assessing the implications of this report.

In addition, any potential proponents of non-network solutions to emerging constraints should note that the lead time for completion of a major network augmentation (such as the development of a new station, or the installation of a new transformer) can easily be up to two to three years, taking into account the need to obtain local authority planning consent. In view of this consideration, the individual risk assessment commentaries for each terminal station will:

• identify the estimated lead time for delivery of the preferred network solution; and/or

• identify the latest date by which the relevant DB(s) will generally require a firm commitment from proponents of non-network alternatives, in order to be confident that the network augmentation can be displaced or deferred without compromising supply reliability in the future.

5.8 Interpreting the dates shown in the risk assessments

All charts and tables in the following risk assessments present data on a calendar year basis. However, the narrative within some of the risk assessments may refer to composite years; for instance “2016/17”, or “summer of 2016/17”.

References to composite years may be made in risk assessments relating to summer peaking stations. In these cases, the peak annual demand would typically be expected to

37 Section 1.5 provides a more detailed description of the processes and timeframes involved in implementing transmission connection projects.
occur around mid to late summer (that is, early in the calendar year, say, from late January to March).

Therefore, where a risk assessment refers to a peak demand occurring in a composite year (such as 2016/17, for instance), the peak would typically be expected to occur in the second year (in this example, 2017), and the relevant data for 2016/17 would be shown in the accompanying tables and charts as 2017.
APPENDIX: ESTIMATION OF BASIC TRANSFORMER RELIABILITY DATA AND EXAMPLE OF EXPECTED TRANSFORMER UNAVAILABILITY CALCULATION

1. Estimation of basic transformer reliability data

The basic transformer reliability data adopted for the risk assessment is estimated as follows:

Based on historic data, a major outage is expected to occur once per 100 transformer-years (reflecting a 1% per annum failure rate). Therefore, in a population of 100 transformers, you would expect one major failure of any one transformer per year.

The mean duration of a major failure is derived from the following data:

<table>
<thead>
<tr>
<th>PROPORTION OF MAJOR FAILURES</th>
<th>MEAN OUTAGE DURATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Costly Major Failures(^38)</td>
<td>0.4 of failures</td>
</tr>
<tr>
<td>Other Major Failures</td>
<td>0.6 of failures</td>
</tr>
</tbody>
</table>

Mean duration of a major failure = (0.4\*5.0 months) + (0.6\*1.0 month) = 2.6 months

2. Sample of expected transformer unavailability calculation

This appendix sets out an example demonstrating the calculation of the “Expected Transformer Unavailability” for a terminal station with two transformers, using the basic reliability data contained in Section 5.4.

| Expected transformer unavailability due to major outage per transformer-year (Refer to Section 5.4 for the base reliability statistics) | A | 0.217% |
| Number of transformers                                                   | B | 2      |
| Expected unavailability of one transformer (probability of being in state N-1) | C=A\*B | 0.434% |
| Expected unavailability of both transformers (probability of being in state N-2)\(^39\) | D=A\*A | 0.00047% |

\(^38\) The costly major failures are those that would result in repair costs greater than 2% of the replacement value of the failed transformer, with a relatively long duration of outage for repair.

\(^39\) The coincident outages of two transformers are considered to be “independent events”. This means that the failure of one transformer is assumed to not affect the availability of the other.
Example Calculation

The following example is used to illustrate the methodology to calculate “Expected Unserved Energy” for a 2-transformer terminal station, given the following data and the load duration curve shown below:

**Required Data:**
- Maximum Demand = 80 MW
- (N-1) Rating = 70 MW
- (N-2) Rating = 0 MW
- Annual Maximum Demand Growth Rate = 3.0%
- Annual Energy Growth Rate = 1.5%
- VCR = $60,000 per MWh

Risk assessment results for first and second order contingencies (i.e. one and two transformers out of service, respectively) over 10 years are presented for this example. It is assumed that the shape of the load duration curve will not change over the forecast period. Detail calculations are shown for the first year.

![Annual Load Duration Curve](image)

**Risk Assessment Calculations for the first year**

Energy at risk for an N-1 contingency is determined as the area below the load duration curve, but in excess of the N-1 rating, as shown above. For this example, this is given by:

- Energy above N-1 Rating in year 1 = 132 MWh

---

40 A VCR of $60,000 per MWh is used for illustrative purposes only.
Similarly, energy at risk for an N-2 contingency is determined as the area below the load duration curve, but in excess of the N-2 rating:

- Energy above N-2 Rating in year 1 = 367,877 MWh

**First Order Contingency (N-1):**

\[
\text{Expected Unserved Energy} = \text{(Energy above N-1 Rating)} \times \text{(N-1 Probability)} \\
= (132 \text{ MWh}) \times (0.434\%) = 0.6 \text{ MWh}
\]

\[
\text{Customer Value} = \text{(Expected Unserved Energy)} \times \text{(VCR)} \\
= (0.6 \text{ MWh}) \times ($60,000 \text{ per MWh}) = $36,000
\]

**Second Order Contingency (N-2):**

\[
\text{Expected Unserved Energy} = \text{(Energy above N-2 Rating)} \times \text{(N-2 Probability)} \\
= (367,877 \text{ MWh}) \times (0.00047\%) = 1.7 \text{ MWh}
\]

\[
\text{Customer Value} = \text{(Expected Unserved Energy)} \times \text{(VCR)} \\
= (1.7 \text{ MWh}) \times ($60,000 \text{ per MWh}) = $102,000
\]

Based on the data set out above, the expected unserved energy and corresponding customer value can be calculated for each year over the next 10 years. The results of these calculations are summarised and presented in the table and chart below. The following conclusions can be drawn from the results:

- The value of expected unserved energy for a 2\textsuperscript{nd} order contingency is comparable to the value of expected unserved energy for a 1\textsuperscript{st} order contingency in the earlier years (when the peak demand is roughly the same as the N-1 rating at the station). However, the combined total value of unserved energy for first and second order contingencies in those early years is highly unlikely to economically justify a large capital investment, such as the installation of a new transformer.

- Over the ten year planning horizon, the value of expected unserved energy for a 1\textsuperscript{st} order contingency grows at a much faster rate than the value of expected unserved energy for a 2\textsuperscript{nd} order contingency.

- The value of expected unserved energy associated with 2\textsuperscript{nd} order contingencies only would be unlikely to be sufficiently high to economically justify any major augmentation. Hence, if a terminal station was expected to remain within its N-1 rating over the planning period, major augmentation (such as the installation of a third transformer) would not be economically justified.

- In undertaking a detailed economic evaluation of network investment, the quantity and value of energy at risk associated with higher order contingencies should be assessed. However, for the purpose of providing an indication of the likely timing of the need for new investment, it is sufficient to consider the expected unserved energy associated with first order contingencies only.

\[41\] A VCR of $60,000 per MWh is used for illustrative purposes only.
Customer Value of Risk for 1st and 2nd Order Contingency

Customer Value (1st Order Contingency)  Customer Value (2nd Order Contingency)
### Summary of Risk Assessment Results for a 2-Transformer Terminal Station Example

<table>
<thead>
<tr>
<th></th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
<th>Year 5</th>
<th>Year 6</th>
<th>Year 7</th>
<th>Year 8</th>
<th>Year 9</th>
<th>Year 10</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximum Demand</strong></td>
<td>80.0</td>
<td>82.4</td>
<td>84.9</td>
<td>87.4</td>
<td>90.0</td>
<td>92.7</td>
<td>95.5</td>
<td>98.4</td>
<td>101.3</td>
<td>104.4</td>
</tr>
<tr>
<td><strong>N-1 Risk Assessment</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rating</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
<td>70.0</td>
</tr>
<tr>
<td>Demand above Rating</td>
<td>10.0</td>
<td>12.4</td>
<td>14.9</td>
<td>17.4</td>
<td>20.0</td>
<td>22.7</td>
<td>25.5</td>
<td>28.4</td>
<td>31.3</td>
<td>34.4</td>
</tr>
<tr>
<td>Energy above Rating</td>
<td>132</td>
<td>231</td>
<td>374</td>
<td>565</td>
<td>838</td>
<td>1,253</td>
<td>1,914</td>
<td>3,003</td>
<td>4,759</td>
<td>7,393</td>
</tr>
<tr>
<td>Probability</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
<td>0.433%</td>
</tr>
<tr>
<td>Expected Unserved Energy</td>
<td>0.6</td>
<td>1.0</td>
<td>1.6</td>
<td>2.4</td>
<td>3.6</td>
<td>5.4</td>
<td>8.3</td>
<td>13.0</td>
<td>20.6</td>
<td>32.0</td>
</tr>
<tr>
<td>Customer Value ($)</td>
<td>36k</td>
<td>60k</td>
<td>96k</td>
<td>144k</td>
<td>216k</td>
<td>324k</td>
<td>498k</td>
<td>780k</td>
<td>1236k</td>
<td>1920k</td>
</tr>
<tr>
<td><strong>N-2 Risk Assessment</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rating</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Demand above Rating</td>
<td>80.0</td>
<td>82.4</td>
<td>84.9</td>
<td>87.4</td>
<td>90.0</td>
<td>92.7</td>
<td>95.5</td>
<td>98.4</td>
<td>101.3</td>
<td>104.4</td>
</tr>
<tr>
<td>Energy above Rating</td>
<td>367,877</td>
<td>373,395</td>
<td>378,996</td>
<td>384,681</td>
<td>390,452</td>
<td>396,308</td>
<td>402,253</td>
<td>408,287</td>
<td>414,411</td>
<td>420,627</td>
</tr>
<tr>
<td>Probability</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
<td>0.00047%</td>
</tr>
<tr>
<td>Expected Unserved Energy</td>
<td>1.7</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
<td>1.9</td>
<td>1.9</td>
<td>1.9</td>
<td>1.9</td>
<td>2.0</td>
</tr>
<tr>
<td>Customer Value ($)</td>
<td>102k</td>
<td>108k</td>
<td>108k</td>
<td>108k</td>
<td>108k</td>
<td>114k</td>
<td>114k</td>
<td>114k</td>
<td>114k</td>
<td>120k</td>
</tr>
</tbody>
</table>
ALTONA/BROOKLYN TERMINAL STATION (ATS/BLTS) 66 kV

Altona/Brooklyn Terminal Station (ATS/BLTS) 66 kV comprises two terminal stations in close proximity, connected by strong sub-transmission ties. The ATS/BLTS 66 kV supply area includes Altona, Brooklyn, Laverton North, Tottenham, Footscray and Yarraville. It is the main source of supply for 57,966 customers. The stations supply both Jemena Electricity Network and Powercor customers.

ATS consists of three 150 MVA 220/66 kV transformers with the 2-3 66 kV bus tie circuit breaker locked open to manage fault levels. Under these arrangements, only one ATS 150 MVA 220/66 kV transformer operates in parallel with the BLTS system. The BLTS rebuild project has recently been completed by AusNet Transmission Group, with two new 150 MVA 220/66 kV transformers supplying the BLTS 66 kV bus.

The existing synchronous condenser connected to the BLTS 66 kV bus was switched off in May 2016 due to age and poor condition. It will be decommissioned in 2017 as it is no longer required.

Magnitude, probability and impact of loss of transformer (N-1 System Condition):

The load characteristic for ATS/BLTS substation is of a mixed nature, consisting of residential and industrial customers. The peak load demand on the entire ATS/BLTS 66 kV network reached 289.6 MW (299 MVA) in summer 2016. A major customer (Qenos) installed a 22.5 MW gas generator in January 2013 and load was reduced from ATS-BLTS due to the generation. This load reduction due to the generation is reflected in the load forecasts.

It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.95.

The graph on the following page depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature. As explained above, the forecast is affected by the introduction of the Qenos embedded generator in summer 2012-13. Further, the completion of Deer Park Terminal Station in 2017 will enable transfers away from the ATS-BLTS Terminal Station. In summer 2016-17 the BATS-BLTS tie will be closed and 12 MW of load will be transferred to Ballarat Terminal Station (BATS).
The “N” rating on the chart indicates the maximum load that can be supplied from ATS-BLTS with all transformers in service. The “N-1” rating on the chart is the load that can be supplied from ATS-BLTS with one 150 MVA transformer out of service.

The graph shows there is sufficient capacity at the station to supply all expected demand at the 50th percentile temperature, over the forecast period, even with one transformer out of service. Under 10th percentile forecast conditions, there is a small amount of load at risk in 2017, which can be managed by utilising load transfers away to ATS, BATS & KTS in the order of 33 MVA. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
ALTONA WEST TERMINAL STATION (ATS West) 66 kV

Altona Terminal Station 66 kV comprises three 150 MVA 220/66 kV transformers. For reliability and maintenance of existing supply requirements, the station is configured so that one transformer operates in parallel with the BLTS system, and is isolated from the other two transformers via a permanently open 2-3 bus tie CB at ATS. This electrically separates the two systems and effectively creates two separate terminal stations. These stations are referred to as ATS/BLTS and ATS West (ATS bus 3 & 4).

Background

The ATS West 66 kV supply area includes Laverton, Laverton North, Altona Meadows, Werribee, Wyndham Vale, Mount Cottrell, Eynesbury, Tarneit, Hoppers Crossing and Point Cook. The station supplies 85,408 Powercor customers, as well as Air Liquide, a company supplied directly from the 66 kV bus at ATS. Air Liquide’s load has been included in the following assessment.

Growth in summer peak demand on the 66 kV network at ATS West has averaged around 1.8% per annum over last five years. The peak load on the station reached 225.4 MW in summer 2016.

It is estimated that:

- For 4 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.95.

ATS West is summer peaking with high demand occurring over a four month period. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the stations operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature. The reduction in load in 2018 is due to load transfers to the proposed Deer Park Terminal Station which is expected to be completed in 2017.
The “N” rating on the chart indicates the maximum load that can be supplied from ATS West with all transformers in service. The “N-1” rating on the chart is the load that can be supplied from ATS West with one 150 MVA transformer out of service.

The graph above shows that there is insufficient capacity to supply the forecast demand at 50th percentile temperature at ATS West if a forced outage of a transformer occurs.

**Magnitude, probability and impact of loss of transformer (N-1 System Condition):**

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

![Annual Energy and Hours at Risk and Expected Customer Value at ATS West under transformer outage condition](image)

**Comments on Energy at Risk**

For an outage of one transformer at ATS West 66 kV, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 490 hours in 2026. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 12,567 MWh in 2026. The estimated value to consumers of the 12,567 MWh of energy at risk is approximately $457.4 million (based on a value of customer reliability of $36,398/MWh). In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at ATS West in 2026 would be anticipated to lead to involuntary supply interruptions that would cost consumers $457.4 million.

It is emphasised however, that the probability of a major outage of one of the two 150 MVA transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at

---

1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
risk (12,568 MWh for 2026) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 54.5 MWh. This expected unserved energy is estimated to have a value to consumers of $2.0 million (based on a value of customer reliability of $36,398/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in 2026 is estimated to be 29,935 MWh. The estimated value to consumers of this energy at risk in 2026 is approximately $1,089 million. The corresponding value of the expected unserved energy (of 130 MWh) is $4.7 million.

These key statistics for the year 2026 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>12,567</td>
<td>$457.4 million</td>
</tr>
<tr>
<td>54.5</td>
<td>$2.0 million</td>
</tr>
<tr>
<td>29,935</td>
<td>$1,089 million</td>
</tr>
<tr>
<td>130</td>
<td>$4.7 million</td>
</tr>
</tbody>
</table>

It is noted that the chart on page 2 indicates that over the period from 2018 to 2026 inclusive, the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast averages approximately $980,000.

**Possible Impact on Customers**

**System Normal Condition (Both transformers in service)**

Applying the 50th percentile and 10th percentile demand forecasts, there is sufficient capacity at Altona West Terminal Station to meet all demand when both transformers are in service.

**N-1 System Condition**

If one of the 150 MVA 220/66 kV transformers at ATS West is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA\(^2\) automatic load shedding scheme which is operated by AusNet Transmission Group’s TOC\(^3\) will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with Powercor’s operational procedures after the operation of the OSSCA scheme.

Possible load transfers away to ATS/BLTS and KTS terminal stations in the event of a transformer failure at ATS West total 13.6 MVA in summer 2017.

---

\(^2\) Overload Shedding Scheme of Connection Asset.  
\(^3\) Transmission Operation Centre
Feasible options for alleviation of constraints

Deer Park Terminal Station (DPTS) 66 kV is a committed terminal station located at the corner of Christies Road and Riding Boundary Road in Deer Park.

DPTS is being constructed with two 225 MVA 220/66 kV transformers and will connect into the existing KTS-GTS 220 kV lines which presently pass through the site. Powercor, Jemena Electricity Networks and AEMO published a regulatory test analysis of the proposed Deer Park Terminal station in May 2012. A copy of the report is available at:


Construction of DPTS is now well advanced, and the station is expected to be commissioned by November 2017 for service during the summer of 2017/18.

The establishment of the new Deer Park terminal station with proposed Truganina zone substation will offload Laverton (LV) and Werribee (WBE) zone substations and ATS West terminal station. As noted above, this option has been assessed in the Regulatory Test report for the proposed Deer Park Terminal Station, which was published in April 2012, and is also subject to further planning work in relation to the proposed Truganina zone substation, with both proposed projects expected to be completed in 2017.

Once Deer Park Terminal Station is installed, there will still be load at risk at ATS West as described in this risk assessment.

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Install additional transformation capacity and reconfigure 66 kV exits at ATS, at an estimated indicative capital cost of $18 million (equating to a total annual cost of approximately $1.8 million per annum). This would result in the station being configured so that three transformers are supplying the ATS West load, and one transformer will continue to provide capacity to the ATS/BLTS system.

2. A new Tarneit zone substation is planned for 2023; however it is not a committed project at this point in time. This zone substation would be supplied from DPTS and will offload Werribee and Laverton zones substations in the order of 40 MW. This will not eliminate the load at risk at ATS West, only reduce it.

3. Demand reduction: There is an opportunity to develop innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of potential demand reduction depends on the customer uptake and would be taken into consideration when determining the optimum timing of any network capacity augmentation.

4. Embedded generation, connected to the ATS 66 kV bus, may substitute capacity augmentations.

Preferred network option(s) for alleviation of constraints

In the absence of commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce
load at ATS, it is proposed to install additional transformation capacity and to reconfigure 66 kV exits at ATS.

On the basis of the present demand forecasts and applying the 2016 VCR estimates, the installation of an additional transformer and the 66 kV exit reconfiguration works at ATS would be expected to be economically justified by 2026. As already noted, the chart on page 2 indicates that over the period from 2018 to 2026 inclusive, the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast averages approximately $980,000 when the 2016 VCR estimate is used. Applying the 2013 VCR estimate, the average annual expected unserved energy value at the 50th percentile demand forecast is approximately $2.0 million per year over the period from 2018 to 2026 inclusive. At the higher VCR value, the preferred network option would be likely to be economically justified by around 2022.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
Altona West Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:

<table>
<thead>
<tr>
<th>Powercor (100%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW</td>
</tr>
<tr>
<td>340</td>
</tr>
</tbody>
</table>

via 2 transformers (Summer peaking)

Normal cyclic rating with all plant in service

<table>
<thead>
<tr>
<th>Summer N-1 Station Rating:</th>
</tr>
</thead>
<tbody>
<tr>
<td>158</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Winter N-1 Station Rating:</th>
</tr>
</thead>
<tbody>
<tr>
<td>176</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Station: ATS West</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>271.3</td>
<td>253.1</td>
<td>258.3</td>
<td>261.7</td>
<td>269.7</td>
<td>272.0</td>
<td>278.8</td>
<td>285.5</td>
<td>288.8</td>
<td>294.2</td>
</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>196.9</td>
<td>183.0</td>
<td>188.5</td>
<td>194.4</td>
<td>200.0</td>
<td>205.7</td>
<td>212.1</td>
<td>217.4</td>
<td>222.5</td>
<td>228.6</td>
</tr>
<tr>
<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>304.8</td>
<td>282.7</td>
<td>287.7</td>
<td>292.6</td>
<td>300.1</td>
<td>304.5</td>
<td>310.0</td>
<td>316.2</td>
<td>321.9</td>
<td>328.3</td>
</tr>
<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
<td>216.2</td>
<td>202.2</td>
<td>208.1</td>
<td>214.2</td>
<td>219.9</td>
<td>226.0</td>
<td>232.6</td>
<td>238.1</td>
<td>243.3</td>
<td>249.8</td>
</tr>
<tr>
<td>N-1 energy at risk at 50% percentile demand (MWh)</td>
<td>5688</td>
<td>3388</td>
<td>3960</td>
<td>4387</td>
<td>5485</td>
<td>5913</td>
<td>7290</td>
<td>8923</td>
<td>10268</td>
<td>12568</td>
</tr>
<tr>
<td>N-1 hours at risk at 50th percentile demand (hours)</td>
<td>181.5</td>
<td>123.5</td>
<td>137.8</td>
<td>151.0</td>
<td>180.8</td>
<td>200.8</td>
<td>260.5</td>
<td>328.8</td>
<td>396.8</td>
<td>490.3</td>
</tr>
<tr>
<td>N-1 energy at risk at 10% percentile demand (MWh)</td>
<td>13002</td>
<td>7583</td>
<td>8659</td>
<td>10018</td>
<td>12294</td>
<td>14388</td>
<td>17412</td>
<td>20935</td>
<td>24690</td>
<td>29935</td>
</tr>
<tr>
<td>N-1 hours at risk at 10th percentile demand (hours)</td>
<td>405.8</td>
<td>229.3</td>
<td>271.0</td>
<td>330.8</td>
<td>419.3</td>
<td>509.3</td>
<td>620.3</td>
<td>732.3</td>
<td>846.0</td>
<td>1007.3</td>
</tr>
<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
<td>24.65</td>
<td>14.68</td>
<td>17.16</td>
<td>19.01</td>
<td>23.77</td>
<td>25.62</td>
<td>31.59</td>
<td>38.66</td>
<td>44.50</td>
<td>54.46</td>
</tr>
<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
<td>56.34</td>
<td>32.86</td>
<td>37.52</td>
<td>43.41</td>
<td>53.28</td>
<td>62.35</td>
<td>75.45</td>
<td>90.72</td>
<td>106.99</td>
<td>129.72</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 50th percentile demand</td>
<td>$0.90M</td>
<td>$0.53M</td>
<td>$0.62M</td>
<td>$0.69M</td>
<td>$0.87M</td>
<td>$0.93M</td>
<td>$1.15M</td>
<td>$1.41M</td>
<td>$1.62M</td>
<td>$1.98M</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
<td>$2.05M</td>
<td>$1.20M</td>
<td>$1.37M</td>
<td>$1.58M</td>
<td>$1.94M</td>
<td>$2.27M</td>
<td>$2.75M</td>
<td>$3.30M</td>
<td>$3.89M</td>
<td>$4.72M</td>
</tr>
<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
<td>$1.24M</td>
<td>$0.73M</td>
<td>$0.85M</td>
<td>$0.96M</td>
<td>$1.19M</td>
<td>$1.33M</td>
<td>$1.63M</td>
<td>$1.98M</td>
<td>$2.30M</td>
<td>$2.80M</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
BALLARAT TERMINAL STATION (BATS) 66kV

Ballarat Terminal Station (BATS) 66 kV consists of two 150 MVA 220/66 kV transformers and is the main source of supply for 70,193 customers in Ballarat and the surrounding area. The station supply area includes Ballarat CBD and Ararat via the interconnected 66 kV tie with Horsham Terminal Station (HOTS).

Magnitude, probability and impact of loss of load

In 2015, one of the 150 MVA transformers failed at BATS. AusNet Transmission Group replaced the failed transformer with the 150 MVA country spare transformer. Accordingly, the station ratings have changed, and these changes are depicted in the graph below. Growth in summer peak demand at BATS has averaged around -0.1 MW (-0.05%) per annum over the last 5 years. The peak load on the station reached 159.4 MW (163.6 MVA) in summer 2016.

It is estimated that:
- For 5 hours per year, 95% of peak demand is expected to be reached under the 50\textsuperscript{th} percentile forecast.
- The station load power factor at the time of peak demand is 0.97.

The graph below depicts the 10\textsuperscript{th} and 50\textsuperscript{th} percentile maximum demand forecasts together with the stations operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.

![BATS Summer Peak Forecast](image)

The N rating on the chart indicates the maximum load that can be supplied from BATS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.
The graph indicates that the overall demand at BATS is expected to remain below its N rating within the 10 year planning period. In addition, the 50\textsuperscript{th} percentile summer peak demand is not expected to exceed the station’s (N-1) rating at 35°C. However, the 10\textsuperscript{th} percentile summer peak demand is forecast to exceed the station’s (N-1) rating at 35°C from summer 2017.

## Comments on Energy at Risk

The table below indicates that for an outage of one transformer at BATS, it is expected that there would be sufficient capacity at the station to supply all demand at the 50\textsuperscript{th} percentile temperature.

However, for an outage of one transformer at BATS, it is expected that from summer 2017, there would be insufficient capacity at the station to supply all demand at the 10\textsuperscript{th} percentile temperature. Demand at BATS is forecast to decline marginally over the ten year planning horizon, so the largest exposure to energy at risk arises in 2017.

In 2017, the energy at risk under N-1 conditions is 150.9 MWh at the 10\textsuperscript{th} percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 16.5 hours in that year. The estimated value to customers of the 150.9 MWh of energy at risk in 2026 is approximately $5.7 million (based on a value of customer reliability of $38,081/MWh\textsuperscript{1}). In other words, at the 10\textsuperscript{th} percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at BATS over the summer of 2017 would be anticipated to lead to involuntary supply interruptions that would cost consumers $5.7 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0\% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217\%. When the energy at risk (150.9 MWh in 2017) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.65 MWh. This expected unserved energy is estimated to have a value to consumers of around $25,000 (based on a value of customer reliability of $38,081/MWh).

These key statistics for the year 2017 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy at risk, at 50\textsuperscript{th} percentile demand forecast</td>
<td>0</td>
</tr>
<tr>
<td>Expected unserved energy at 50\textsuperscript{th} percentile demand</td>
<td>0</td>
</tr>
<tr>
<td>Energy at risk, at 10\textsuperscript{th} percentile demand forecast</td>
<td>150.9</td>
</tr>
<tr>
<td>Expected unserved energy at 10\textsuperscript{th} percentile demand</td>
<td>0.65</td>
</tr>
</tbody>
</table>

\textsuperscript{1} The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

- Installation of a third 220/66 kV transformer (150 MVA) at BATS at an indicative capital cost of $14 million.

- Demand reduction: There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction would depend on the customer uptake and would be taken into consideration when determining the optimum timing for any future capacity augmentation.

- Embedded generation in order of 25 MVA connected to the network supplied by BATS 66 kV bus may help to defer augmentation beyond the forecast period, depending on the expected incidence of reverse power flows associated with any new embedded generation.

- There are presently several large embedded 66 kV wind farm proposals in the area which may drive the need for an additional 220/66 kV transformer at BATS to accommodate the reverse power flow expected at BATS.

Preferred option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at BATS, it is proposed to:

1. Install a third 220/66 kV transformer (150 MVA) at BATS at an indicative capital cost of $14 million. This equates to a total annual cost of approximately $1.4 million per annum. On the basis of the medium economic growth scenario and both 50th and 10th percentile weather probability, the transformer would not be expected to be required before 2026 to support the critical peak demand.

2. As a temporary measure, maintain contingency plans to transfer load quickly to the Horsham Terminal Station (HOTS) by the use of the 66 kV tie lines between BATS and HOTS in the event of an unplanned outage of one transformer at BATS under critical loading conditions. This load transfer is in the order of 17 MVA. Under these temporary measures, affected customers would be supplied from the 66 kV tie line infrastructure on a radial network, thereby reducing the level of supply reliability they receive.

3. Embedded generation in order of 25 MVA connected to the network supplied by BATS 66 kV bus will help to defer augmentation. As already noted, proposals to install 66 kV connected wind generation in the area may drive the need for a third 220/66 kV transformer to accommodate the reverse power flow expected.

4. Powercorp is trialling a 2 MW battery storage connected to a 22 kV feeder exit at Ballarat South zone substation which will provide some relief during a BATS transformer outage.

5. Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for rural areas (refer Section 5.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.
The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
## BATS Terminal Station
### Detailed data: Magnitude and probability of loss of load

#### Distribution Businesses supplied by this station:
- Powercor (100%)

#### Normal cyclic rating with all plant in service
- **MW:** 358
- **VMA:** via 2 transformers (summer)

#### Summer N-1 Station Rating:
- 183
  
  [See Note 1 below for interpretation of N-1]

#### Winter N-1 Station Rating:
- 206

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>183.2</td>
<td>184.3</td>
<td>184.1</td>
<td>183.7</td>
<td>185.0</td>
<td>183.3</td>
<td>184.7</td>
<td>184.3</td>
<td>182.4</td>
<td>181.8</td>
</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>173.9</td>
<td>174.3</td>
<td>175.4</td>
<td>177.2</td>
<td>177.9</td>
<td>178.4</td>
<td>179.3</td>
<td>179.0</td>
<td>178.4</td>
<td>182.6</td>
</tr>
<tr>
<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>205.7</td>
<td>205.2</td>
<td>205.6</td>
<td>203.9</td>
<td>204.6</td>
<td>204.0</td>
<td>203.0</td>
<td>203.2</td>
<td>201.0</td>
<td>200.5</td>
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<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
<td>206.5</td>
<td>202.2</td>
<td>183.7</td>
<td>186.0</td>
<td>186.8</td>
<td>187.5</td>
<td>188.6</td>
<td>188.4</td>
<td>187.7</td>
<td>192.5</td>
</tr>
<tr>
<td>N-1 energy at risk at 50% percentile demand (MWh)</td>
<td>0.0</td>
<td>0.5</td>
<td>0.4</td>
<td>0.2</td>
<td>0.9</td>
<td>0.1</td>
<td>0.7</td>
<td>0.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>N-1 hours at risk at 50% percentile demand (hours)</td>
<td>0.3</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>N-1 energy at risk at 10% percentile demand (MWh)</td>
<td>150.9</td>
<td>142.9</td>
<td>148.9</td>
<td>122.8</td>
<td>123.8</td>
<td>109.6</td>
<td>119.9</td>
<td>84.1</td>
<td>78.6</td>
<td>78.6</td>
</tr>
<tr>
<td>N-1 hours at risk at 10% percentile demand (hours)</td>
<td>16.5</td>
<td>15.8</td>
<td>14.3</td>
<td>14.8</td>
<td>14.8</td>
<td>14.8</td>
<td>13.5</td>
<td>13.8</td>
<td>11.0</td>
<td>10.5</td>
</tr>
<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
</tr>
<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
<td>$0.65M</td>
<td>$0.62M</td>
<td>$0.53M</td>
<td>$0.58M</td>
<td>$0.54M</td>
<td>$0.47M</td>
<td>$0.48M</td>
<td>$0.36M</td>
<td>$0.34M</td>
<td>$0.00M</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 50th percentile demand</td>
<td>$0.01M</td>
<td>$0.01M</td>
<td>$0.01M</td>
<td>$0.01M</td>
<td>$0.01M</td>
<td>$0.01M</td>
<td>$0.01M</td>
<td>$0.01M</td>
<td>$0.00M</td>
<td>$0.00M</td>
</tr>
</tbody>
</table>

### Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. “Expected unserved energy” means “N-1 energy at risk” for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, as described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx]).
BENDIGO TERMINAL STATION (BETS) 22 kV

Bendigo Terminal Station (BETS) 22 kV consists of two 75 MVA 235/22.5 kV transformers supplying the 22 kV network ex-BETS. These two transformers have been in service since mid 2013 and they have enabled the separation of the 66 kV and 22 kV points of supply, and the transfer of load from the existing 230/66/22kV transformers. This configuration is the main source of supply for 26,076 customers in Bendigo and the surrounding area. The station supply area includes Marong, Newbridge and Lockwood.

Magnitude, probability and impact of loss of load

BETS 22 kV demand is summer peaking. Growth in summer peak demand on the 22 kV network at BETS has averaged around 2.4 MVA (5.3%) per annum over the last 5 years. The peak load for the 22 kV network now on the station reached 68.9 MW in summer 2016. There have been load transfers from Eaglehawk Zone Substation to BETS22 which have contributed to the higher peak demand in 2016 compared to 2015. It is estimated that:

- For 10 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.98.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.

![BETS22 Summer Peak Forecast](image)

The above graph shows that there is sufficient capacity at the station to supply all expected demand at the 50th and 10th percentile temperature, over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
BENDIGO TERMINAL STATION (BETS) 66 kV

Background

In 2013, AusNet Transmission Group commissioned 2x75 MVA 220/22 kV transformers to pick up the 22 kV load from the tertiary of the existing 230/66/22 kV transformers. The 66 kV and 22 kV points of supply at Bendigo Terminal Station are now segregated and supplied from separate transformers.

Also in 2013, two 70/57/51 MVA 230/66/22 kV transformers were retired and one new 150 MVA 220/66 kV transformer was commissioned in service supplying the 66 kV buses in parallel with one existing 125/125/40 MVA 230/66/22 kV transformer. These transformers provide the main source of 66 kV supply for 58,672 customers in Bendigo and the surrounding area. The station supply area includes Bendigo CBD, Eaglehawk, Charlton, St. Arnaud, Maryborough and Castlemaine.

AusNet Transmission Group down-rated the transformers in 2015. As a result the BETS 66 station has new ratings with the N rating reduced from 328 MVA to 310.9 MVA and the N-1 rating reduced from 150 MVA to 146.7 MVA in summer. These new ratings are depicted in the graph below.

Magnitude, probability and impact of loss of load

Growth in summer peak demand at BETS 66 kV has averaged around -2.7 MVA (-0.9%) per annum over the last 5 years. The peak load on the station reached 160.2 MW in summer of 2016. It is estimated that:

- For 10 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at time of peak demand is 0.99.

BETS 66 kV demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperatures.
The (N) rating on the chart indicates the maximum load that can be supplied from BETS with all transformers in service. Exceeding this level will initiate automatic load shedding by AusNet Transmission Group’s automatic load shedding scheme.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

![Annual Energy and Hours at Risk and Expected Customer Value at BETS66 under transformer outage condition](image)

**Comments on Energy at Risk**

For a major outage of one transformer at BETS 66 kV during the summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 74 hours in 2017. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 921 MWh in 2017. The estimated value to consumers of the 921 MWh of energy at risk is approximately $36.2 million (based on a value of customer reliability of $39,242/MWh). In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at BETS 66kV in 2017 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately $36.2 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (921 MWh for 2017) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 4 MWh. This expected unserved energy is estimated to

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1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
have a value to consumers of around $0.16 million, (based on a value of customer reliability of $39,242/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50\textsuperscript{th} percentile) summer temperatures occurring in each year. Under 10\textsuperscript{th} percentile temperature conditions, the energy at risk in 2017 is estimated to be 2,698 MWh. The estimated value to consumers of this energy at risk in 2017 is approximately $105.9 million. The corresponding value of the expected unserved energy (of 11.7 MWh) is approximately $0.46 million.

These key statistics for the year 2017 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy at risk, at 50\textsuperscript{th} percentile demand forecast</td>
<td>921</td>
</tr>
<tr>
<td>Expected unserved energy at 50\textsuperscript{th} percentile demand</td>
<td>4.0</td>
</tr>
<tr>
<td>Energy at risk, at 10\textsuperscript{th} percentile demand forecast</td>
<td>2,698</td>
</tr>
<tr>
<td>Expected unserved energy at 10\textsuperscript{th} percentile demand</td>
<td>11.7</td>
</tr>
</tbody>
</table>

It is noted that the demand at BETS 66 is expected to decrease over the forecast period. Therefore, over the forecast period, the energy at risk and expected unserved energy are also expected to decline from the levels forecast for 2017.

**Possible impacts of a transformer outage on customers**

If one of the 230/66/22 kV transformers at BETS 66 kV is taken off line during peak loading times and the N-1 station rating is exceeded, the OSSCA\textsuperscript{2} automatic load shedding scheme which is operated by AusNet Transmission Group’s TO C\textsuperscript{3} will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with Powercor’s operational procedures after the operation of the OSSCA scheme.

**Feasible options for alleviation of constraints**

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or alleviate the emerging constraint over the next ten year planning horizon:

1. Implement a contingency plan to transfer 3.0 MVA of load away to BETS 22 kV, WETS, HOTS and SHTS in the event of loss of a transformer at BETS 66 kV.
2. Install an additional 150 MVA 220/66 kV transformer at BETS 66 kV.
3. Demand reduction: There is an opportunity for voluntary demand reduction to reduce peak demand during times of network constraint. The amount of demand reduction

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\textsuperscript{2} Overload Shedding Scheme of Connection Asset.

\textsuperscript{3} Transmission Operation Centre.
would be taken into consideration when determining the optimum timing for the capacity augmentation.

4. Embedded generation, connected to the BETS 66 kV bus, may defer the need for an additional 220/66 kV transformer at BETS 66 kV.

**Preferred option(s) for alleviation of constraints**

As already noted, a contingency plan to transfer 3.0 MVA of load to BETS 22 kV, WETS and SHTS will be implemented in the event of the loss of one of the BETS 220/66 kV transformers.

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at BETS 66 kV, it is proposed to install an additional 150 MVA 220/66 kV transformer at BETS 66 kV, at an estimated capital cost of $14 million. This equates to a total annual cost of approximately $1.4 million per annum. However, it is expected that the additional capacity will not be economically justified during the forecast period.

Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for rural areas (refer to Section 5.5), a spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
Bendigo Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)
Normal cyclic rating with all plant in service: 310.9 MVA via 2 transformers (Summer peaking)

Summer N-1 Station Rating: 146.7 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 173.7 MVA

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>178.4</td>
<td>177.1</td>
<td>175.8</td>
<td>173.3</td>
<td>173.6</td>
<td>170.3</td>
<td>170.3</td>
<td>169.8</td>
<td>167.1</td>
<td>165.8</td>
</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>130.8</td>
<td>129.4</td>
<td>129.0</td>
<td>128.7</td>
<td>128.2</td>
<td>127.8</td>
<td>127.8</td>
<td>127.0</td>
<td>126.2</td>
<td>127.7</td>
</tr>
<tr>
<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>197.1</td>
<td>195.0</td>
<td>192.8</td>
<td>189.9</td>
<td>188.5</td>
<td>186.0</td>
<td>184.5</td>
<td>183.3</td>
<td>181.1</td>
<td>179.8</td>
</tr>
<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
<td>133.8</td>
<td>132.5</td>
<td>132.2</td>
<td>132.0</td>
<td>131.6</td>
<td>131.2</td>
<td>131.2</td>
<td>131.3</td>
<td>130.6</td>
<td>129.6</td>
</tr>
<tr>
<td>N-1 energy at risk at 50% percentile demand (MWh)</td>
<td>921.2</td>
<td>837.0</td>
<td>750.6</td>
<td>608.0</td>
<td>624.0</td>
<td>457.1</td>
<td>454.7</td>
<td>431.8</td>
<td>320.2</td>
<td>273.4</td>
</tr>
<tr>
<td>N-1 hours at risk at 50th percentile demand (hours)</td>
<td>74</td>
<td>69.75</td>
<td>64.75</td>
<td>58.25</td>
<td>58.75</td>
<td>48.75</td>
<td>48.75</td>
<td>48.5</td>
<td>46.75</td>
<td>38.75</td>
</tr>
<tr>
<td>N-1 energy at risk at 10% percentile demand (MWh)</td>
<td>2697.9</td>
<td>2447.5</td>
<td>2206.2</td>
<td>1898.4</td>
<td>1761.8</td>
<td>1528.7</td>
<td>1391.4</td>
<td>1292.6</td>
<td>1116.9</td>
<td>1015.9</td>
</tr>
<tr>
<td>N-1 hours at risk at 10th percentile demand (hours)</td>
<td>140.5</td>
<td>132.25</td>
<td>123.75</td>
<td>113.5</td>
<td>108</td>
<td>101</td>
<td>95.5</td>
<td>91.25</td>
<td>83.5</td>
<td>79</td>
</tr>
<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
<td>4.0</td>
<td>3.6</td>
<td>3.3</td>
<td>2.6</td>
<td>2.7</td>
<td>2.0</td>
<td>2.0</td>
<td>1.9</td>
<td>1.4</td>
<td>1.2</td>
</tr>
<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
<td>11.7</td>
<td>10.6</td>
<td>9.6</td>
<td>8.2</td>
<td>7.6</td>
<td>6.6</td>
<td>6.0</td>
<td>5.6</td>
<td>4.8</td>
<td>4.4</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 50th percentile demand</td>
<td>$0.16M</td>
<td>$0.14M</td>
<td>$0.13M</td>
<td>$0.10M</td>
<td>$0.11M</td>
<td>$0.08M</td>
<td>$0.08M</td>
<td>$0.07M</td>
<td>$0.05M</td>
<td>$0.05M</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
<td>$0.46M</td>
<td>$0.42M</td>
<td>$0.38M</td>
<td>$0.32M</td>
<td>$0.30M</td>
<td>$0.26M</td>
<td>$0.24M</td>
<td>$0.22M</td>
<td>$0.19M</td>
<td>$0.17M</td>
</tr>
<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
<td>$0.25M</td>
<td>$0.22M</td>
<td>$0.20M</td>
<td>$0.17M</td>
<td>$0.16M</td>
<td>$0.13M</td>
<td>$0.13M</td>
<td>$0.12M</td>
<td>$0.10M</td>
<td>$0.08M</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station transformer output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. “Expected unserved energy” means "energy at risk" multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
BROOKLYN TERMINAL STATION (BLTS) 22 kV

The Brooklyn Terminal Station (BLTS) 22 kV supply area includes Altona, Brooklyn, Laverton North, Tottenham, Footscray and Yarraville. The station supplies both Jemena Electricity Network and Powercor customers.

Brooklyn Terminal Station (BLTS) 22 kV was rebuilt by AusNet Transmission Group during 2012-13, with the existing two 60 MVA 220/22 kV transformers plus a 35 MVA 66/22 kV tie transformer/phase angle regulator (PAR) being retired and replaced by two new 75 MVA 220/22 kV transformers, namely L1 & L3. This configuration is the main source of supply for 7,525 customers in Brooklyn and the surrounding area.

The load characteristic for BLTS 22 kV substation is of a mixed nature, consisting of residential and industrial customers. In recent years, the industrial load has declined in the area; however this has been offset by some growth from residential developments. Growth in summer peak demand on the 22 kV network at BLTS is expected to decline at an average of around 1.2% per annum over the next ten years. The peak load demand on the entire BLTS 22 kV network reached 58 MW (66.2 MVA) in summer 2016. It is estimated that:

- For 7 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer power factor at the time of peak demand is 0.88.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.
The “N” rating on the chart indicates the maximum load that can be supplied from BLTS 22 kV Terminal Station with all transformers in service. The “N-1” rating on the chart is the load that can be supplied with one 75 MVA transformer out of service.

The graph shows there is sufficient capacity at the station to supply all expected demand at the 10th and 50th percentile temperature, over the forecast period, with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
BRUNSWICK TERMINAL STATION 22 kV (BTS 22 kV)

BTS 22 kV is a terminal station located in an inner northern suburb of Melbourne and shared by Jemena Electricity Networks (55%) and CitiPower (45%). It operates at 220/22 kV and supplies a total of approximately 45,000 customers in the Brunswick, Fitzroy, Northcote, Fairfield, Essendon, Ascot Vale and Moonee Ponds areas.

Magnitude, probability and impact of loss of load

BTS 22 kV is a summer critical station with three 75 MVA transformers operating in parallel.

The peak load on the station transformer reached 92.8 MW (or 93.0 MVA) in summer (January) 2016.

It is estimated that:

- For 12 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer load power factor at the time of peak demand is 1.0.

The graph below depicts the BTS 22 kV operational “N-1” rating (for an outage of one transformer) at ambient temperatures of 38°C and 43°C, and the 50th and 10th percentile summer maximum demand forecasts1.

The graph shows there is sufficient capacity to supply all anticipated loads and that no customers would be at risk if a forced transformer outage occurred at BTS 22 kV over the forecast period. Accordingly, no capacity augmentation or other corrective action is planned at BTS 22 kV over the next ten years.

1 Note that station transformer output capability rating and transformer loading are shown in the graph.
BRUNSWICK TERMINAL STATION 66 kV (BTS 66 kV)

BTS 66 kV is a new 66 kV source of supply established in late 2016. It consists of 3 x 225 MVA 220/66 kV transformers to reinforce the security of supply to the northern and inner suburbs and the Central Business District areas, and to provide future supply to the nearby suburbs of Brunswick, Brunswick West, Northcote, Carlton, Fitzroy and Collingwood.

Magnitude, probability and impact of loss of load

The initial BTS load includes transfers of load from WMTS 66 kV. Further load transfers from WMTS 66, RTS 66 and WMTS 22 will occur in 2018 and 2020 as shown below. The BTS demand will be summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35 deg C ambient temperature.

The 50th percentile peak load on the station is expected to reach 141.7 MW in summer 2016/17 with a station load power factor of 0.97.

The number of hours per year in which 95% of peak load is expected to be reached is estimated to be 3 hours.

The graph shows that there is expected to be sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action at the station is not expected to arise over the current ten year planning horizon.
CRANBOURNE TERMINAL STATION (CBTS)

Cranbourne Terminal Station (CBTS) was originally commissioned with two 150 MVA 220/66 kV transformers in 2005 to reinforce the security of supply for United Energy and AusNet Electricity Services customers and to off-load East Rowville Terminal Station (ERTS). In order to supply the growing electricity demand in the area, a third 150 MVA 220/66 kV transformer was commissioned in 2009.

The geographic area supplied by CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west. The electricity distribution networks for this area are the responsibility of both AusNet Electricity Services (66%) and United Energy (34%).

Magnitude, probability and impact of loss of load

The summer peak demand at CBTS 66 kV has increased by 133 MVA, which is equivalent to an annual growth rate of 5.4%, between 2008 and 2016. The peak demand on the station reached 430.1 MW (442.9 MVA) in summer 2015/16 which is the highest recorded peak demand so far. The peak demand is 2.3% higher than the previous highest peak demand (recorded in summer 2013/14). The station load has a power factor of 0.971 at maximum demand. Demand at CBTS 66 kV is expected to exceed 95% of the 50th percentile peak demand for 2 hours per annum.

The risk of interruption to CBTS 66 kV supplies, for a single contingency event was assessed as being unacceptable in 2010. A Request For Information (RFI) was published by AusNet Electricity Services, United Energy and Australian Energy Market Operator (AEMO) in March 2011 to seek non-network alternatives to this emerging constraint. Two offers were received, one for demand management and one for connecting embedded generation. AusNet Electricity Services and United Energy commenced negotiation with the generation proponent to establish a network support contract that would allow the installation of the fourth 220/66kV 150 MVA transformer to be deferred. However the forecast demand growth rate has declined significantly due to weaker economic conditions, appliance energy efficiency, rooftop solar generation and the impact of increases in the cost of electricity. This, compounded with a lower VCR has deferred the economic timing for the installation of a fourth transformer or a network support contract, as demonstrated later in this risk assessment.

The economic timing and nature of the augmentation or network support option are yet to be determined. Accordingly, the following risk assessment is for the current configuration with three transformers.

CBTS 66 kV is a summer peaking station and is expected to be loaded above its “N-1” rating in summer. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s expected operational “N” rating (all transformers in service) and the “N-1” rating at 35°C as well as 40°C ambient temperatures.
The “N” rating on the chart indicates the maximum load that can be delivered from CBTS 66 kV with all transformers in service. Exceeding this level will initiate AusNet Transmission Group’s automatic load shedding scheme (OSSCA).

The winter ratings of transformers are higher than the summer ratings due to lower ambient temperatures. Thus, energy at risk during the winter period is generally lower than the summer period for summer peaking stations. The graph below demonstrates the 10th and the 50th percentile winter maximum demand forecast together with the station’s operational “N” rating and “N-1” rating for winter.
The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the “N-1” capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

**Comments on Energy at Risk**

As already noted, CBTS 66 kV is a summer peaking station and most of the energy at risk occurs in the summer period because the rating of the transformers is lower at higher ambient temperatures in addition to higher summer demand. For simplicity therefore, the comments below focus on the energy at risk over the summer period.

For an outage of one 220/66 kV transformer at CBTS, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 107 hours in 2023/24. The energy at risk under “N-1” conditions is estimated to be 5,093 MWh in 2023/24. The estimated value to consumers of the 5,093 MWh of energy at risk is approximately $182 million (based on a value of customer reliability of $35,670/MWh). In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one 220/66 kV transformer at CBTS for the entire duration of the summer of 2023/24 would be anticipated to lead to involuntary supply interruptions that are valued by consumers at $182 million.

It is emphasised however, that the probability of a major outage of one of the transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (5,093 MWh) is weighted by this low unavailability, the expected unserved energy is estimated to be around 33.1 MWh. This expected unserved energy is estimated to have a

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1 The value of unserved energy is derived from the sector values given in Table 1 in Section 2.4, weighted in accordance with the composition of the load at this terminal station.
value to consumers of around $1.18 million (based on a value of customer reliability of $35,670/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of moderate temperatures occurring in each year. Under higher temperature conditions (that is, at the 10th percentile level), there is a higher amount of energy at risk under “N-1” and “N” conditions at CBTS in 2023/24. The “N-1” and “N” energy at risk in summer 2023/24 is estimated to be 9,531 MWh and 181 MWh respectively. The total estimated value to consumers of this energy at risk in 2023/24 is approximately $346 million. The corresponding value of the expected unserved energy is $8.67 million.

These key statistics for the year 2023/24 under “N” and “N-1” outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>$0</td>
</tr>
<tr>
<td>5,093</td>
<td>$182 million</td>
</tr>
<tr>
<td>33.1</td>
<td>$1.18 million</td>
</tr>
<tr>
<td>181</td>
<td>$6.46 million</td>
</tr>
<tr>
<td>9,531</td>
<td>$340 million</td>
</tr>
<tr>
<td>243</td>
<td>$8.67 million</td>
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</table>

Possible impacts of a transformer outage on customers

If one of the 220/66 kV transformers at CBTS is taken off line during peak loading times and the N-1 station rating is exceeded, the Overload Shedding Scheme for Connection Assets (OSSCA)\(^2\) which is operated by AusNet Transmission Group’s TOC\(^3\) will act swiftly to reduce the loads in blocks to within ratings of available plant. In the event of OSSCA operating, it would automatically shed up to 200 MVA of load, affecting up to 73,000 customers in 2016/17. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy’s and AusNet Electricity Services’ operational procedures after the operation of the OSSCA scheme.

\(^2\) OSSCA is designed to protect connection transformers against transformer damage caused by overloads. Damaged transformers can take months to repair or replace, which can result in prolonged, long term risks to the reliability of customer supply.

\(^3\) Transmission Operations Centre
Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint.

1. Implement contingency plans to transfer load to adjacent terminal stations: Both AusNet Electricity Services and United Energy have established and implemented the necessary plans that enable load transfers under contingency conditions via emergency 66 kV ties to the adjacent terminal stations at East Rowville (ERTS 66 kV), Tyabb (TBTS 66 kV) and Heatherton (HTS 66 kV). The emergency 66 kV ties can be in operation within 2 hours and have a combined capability to transfer up to 150 MVA of load. The 22 kV distribution network is also capable of transferring a further 55 MVA.

2. Establish a new 220/66 kV terminal station: AusNet Electricity Services expects that a new terminal station in the Pakenham area (with a site yet to be acquired) will be required in around 10 to 20 years to service demand growth in the region. This development will help to off-load CBTS as well as addressing constraints on the existing 66 kV sub-transmission network from CBTS to the Pakenham area. AusNet Electricity Services will carry out planning studies to assess whether this option is economic, and if so, to determine the optimal timing of any investment. An alternative would be to develop a new terminal station on a reserved site in North Pearcedale. The North Pearcedale site, however, is not located within the growth area and is considered suboptimal at this time.

3. Install a 4th 220/66 kV transformer at Cranbourne Terminal Station: The site has provision for a 4th transformer and implementing this option is relatively straight forward, however it would require 66 kV lines to be re-arranged so that the station can operate with split 66 kV buses in order to maintain fault levels within equipment ratings.

4. Install two new 50 MVAR 66 kV capacitor banks: CBTS currently does not have 66 kV capacitor banks and the station operates with a power factor around 0.971 lagging in summer. Two 50 MVAR 66 kV capacitor banks will help to reduce the net MVA supplied by the transformers by approximately 13 MVA and would defer a network augmentation by one to two years. AEMO have also been considering installing capacitors at CBTS to support the transmission network and any opportunity to install 66 kV capacitors at CBTS to provide benefits in both areas will be identified through joint planning with AEMO.

5. Demand Management: United Energy and AusNet Electricity Services have developed a number of innovative network tariffs that encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and the subsequent change in the load pattern and will be taken into consideration when determining the optimum timing for the capacity augmentation.

6. Embedded Generation: Embedded generation, with a capacity in the order of 20 MW, connected to the CBTS 66 kV bus, will defer the need for augmentation by one to two years.

Preferred network option for alleviation of constraints

Although AusNet Electricity Services and United Energy have commenced the process of addressing the supply risks at CBTS, as discussed earlier, the recent reduction in demand forecasts coupled with the recent reduction in the VCR estimate indicate that these activities can be deferred. The preferred option of network support and then the installation of a fourth 150 MVA 220/66 kV transformer can be deferred until 2024 based on the latest demand
forecasts, and the 2016 VCR estimate. The installation of fourth transformer would be
economic in 2022 based on AEMO’s previous VCR estimate (escalated to 2016 dollars).
The installation of two new 50 MVAR 66 kV capacitor banks at CBTS could be economic
earlier if they also supported the needs of the transmission network.

Prior to implementing any augmentation option it is proposed to implement the following
temporary measures to cater for an unplanned outage of one transformer at CBTS under
critical loading conditions:

- maintain contingency plans to transfer load to adjacent terminal stations;
- fine-tune the OSSCA scheme settings to minimise the impact on customers of any
  automatic load shedding that may take place; and
- subject to the availability of a spare 220/66 kV transformer for metropolitan areas
  (refer Section 5.5), a spare transformer can be used to temporarily replace a failed
  transformer.

The capital cost of installing a fourth 150 MVA 220/66 kV transformer at CBTS is estimated
to be $20 million. The cost of establishing, operating and maintaining a new transformer
would be recovered from network users through network charges, over the life of the asset.
The estimated total annual cost of this network augmentation is approximately $2 million.
This cost provides a broad upper bound for the maximum annual network support payment
which may be available to embedded generators or customers to reduce forecast demand,
and to defer or avoid the transmission connection component of this augmentation. Any non-
network solution that defers this augmentation for say 1-2 years, will not have as much
potential value (and contribution available from distributors) as a solution that eliminates or
defers the augmentation for, say, 10 years.

The table on the following page provides more detailed data on the station rating, demand
forecasts, energy at risk and expected unserved energy.
## CRANBOURNE TERMINAL STATION

### Detailed data: Magnitude and probability of loss of load

**Distribution Businesses supplied by this station:** [United Energy (34%)] and [AusNet Electricity Services (66%)]

**Normal cyclic rating with all plant in service:** 538 MVA via 3 transformers (Summer peaking)

**Summer N-1 Station Rating:** 359 MVA [See Note 1 below for interpretation of N-1]

**Winter N-1 Station Rating:** 411 MVA

### Station: CBTS 66 kV

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<th>2019</th>
<th>2020</th>
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### Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at a summer ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled [Victorian Electricity Planning Approach](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx), published in June 2016.
DEER PARK TERMINAL STATION (DPTS) 66 kV

Deer Park Terminal Station (DPTS) 66 kV is a committed terminal station located at the corner of Christies Road and Riding Boundary Road in Deer Park. It is expected to be commissioned for service in the fourth quarter of 2017. It is required to offload both transformer groups at KTS by November 2017 to avoid excessive load at risk and load exceeding ‘N’ ratings of plant at KTS in summer 2017/18. It is planned to transfer SU (Sunshine) zone substation from KTS (B1,2,5) transformer group and MLN (Melton) zone substation from KTS (B3,4) group to the new DPTS.

DPTS will also supply a nearby new zone substation, Truganina (TNA) which is required by November 2017 to offload nearby LV (Laverton), LVN (Laverton North), SU and WBE (Werribee) zone substations, and to augment supply to the fast-growing western suburbs of Melbourne.

The transfer of load from LV and LVN zone substations which are supplied from ATS West and ATS/BLTS terminal stations respectively also defers augmentation at those terminal stations.

DPTS is to be constructed with two 225 MVA 220/66 kV transformers and will connect into the existing KTS-GTS 220 kV lines which presently pass through the site. Powercor, Jemena Electricity Networks and AEMO published a regulatory test analysis of the proposed Deer Park Terminal station in April 2012. A copy of the report is available at:


Magnitude, probability and impact of loss of load

The initial 50th percentile forecast load is expected to be 194.8 MW and rising to 212.4 MW by 2026 due to the high load growth in the western suburbs of Melbourne and additional transfers from LVN, SU, LV and WBE zone substations.

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of peak demand will be 0.94

The graph below depicts the 10th and 50th percentile maximum demand forecasts together with the stations estimated operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.
The (N) rating on the chart indicates the maximum load that can be supplied from DPTS with all transformers in service. The “N-1” rating on the chart is the load that can be supplied from DPTS with one 225 MVA transformer out of service.

The graph shows there is sufficient capacity at the station to supply all expected demand at the 10th and 50th percentile temperature, over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
EAST ROWVILLE TERMINAL STATION (ERTS)

ERTS is the main source of supply for part of the outer south-eastern corridor of Melbourne. The geographic coverage of the area supplied by this station spans from Scoresby in the north to Lyndhurst in the south, and from Belgrave in the east to Mulgrave in the west. The electricity supply network for this large region is split between United Energy (UE) and AusNet Electricity Services.

ERTS 66 kV is a summer critical station. The station reached its highest recorded peak demand of 504.9 MW (523.4 MVA) in summer 2009 under extreme weather conditions. The recorded demand in summer 2016 was 426.5 MW (437.8 MVA). Five embedded generation units over 1 MW are connected at ERTS 66 kV.¹

The risk of supply interruption at ERTS 66 kV, for a single contingency event was assessed as being unacceptable in 2007. As a result, a Regulatory Test was undertaken by both AusNet Electricity Services and United Energy which identified the installation of a fourth 150 MVA 220/66 kV transformer as the most economic network solution. A new fourth transformer was installed at ERTS and commissioned in January 2012. Prior to the installation of a fourth transformer, Cranbourne Terminal Station (CBTS) was established in 2005 to off-load ERTS.

In 2012, AusNet Electricity Services transferred approximately 15 MVA of load away from ERTS to CBTS. This load transfer is reflected in the figure below.

United Energy’s new Keysborough zone substation was commissioned in 2014-15. Approximately 7 MW of demand was transferred away from ERTS to HTS in 2014-15, after the new Keysborough zone substation was commissioned. This load transfer is also reflected in the figure below.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile total summer maximum demand forecasts together with the station’s expected operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.

¹ The maximum demand forecasts adopted in this risk analysis excludes the impact of the five generation schemes.
The N rating on the graph indicates the maximum load that can be supplied from ERTS with all transformers in service. Exceeding this level will require manual load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that:

- The overall demand at ERTS is expected to remain below the station’s N rating within the 10 year planning period.
- The 10\textsuperscript{th} and 50\textsuperscript{th} percentile overall summer demand forecast is expected to remain within the N-1 rating for the entire planning period.

The station load is forecast to have a power factor of 0.981 at times of peak demand. The demand at ERTS is expected to exceed 95\% of the 50\textsuperscript{th} percentile peak demand for approximately 8 hours per annum.

With the commissioning of the fourth transformer in 2012, the ERTS 66 kV bus was split into two bus groups (B12 and B34) containing two transformers in each group during normal operation in order to reduce the 66 kV fault level.

In the event of a transformer outage, the normally open 66 kV bus tie circuit breaker will automatically be closed to share the demand across the other three transformers. The following sections discuss the demand on these two bus groups under normal operating conditions.

**Transformer group ERTS (B12) Summer Peak Forecasts**

This bus group supplies UE’s Mulgrave and Lyndale zone substations and AusNet Electricity Services’ Ferntree Gully, Lysterfield and Belgrave zone substations.

The graph below depicts the ERTS (B12) bus group rating with both transformers in service (“N” rating), the historical demand and the 10\textsuperscript{th} and 50\textsuperscript{th} percentile summer maximum demand forecasts.
The graph indicates that both the 10th and 50th percentile forecast maximum demands connected to the bus group ERTS (B12) are below its N rating for the entire planning period. Therefore, the maximum demand at ERTS (B12) bus group is not expected to exceed its total capacity under normal operation at any time over the 10 year planning period.

Transformer group ERTS (B34) Summer Peak Forecasts

This bus group supplies UE’s Dandenong South, Dandenong and Dandenong Valley zone substations and AusNet Electricity Services’ Hampton Park zone substation.

The graph below depicts the ERTS (B34) bus group rating with both transformers in service (“N” rating), the historical demand and the 10th and 50th percentile summer maximum demand forecasts.

As previously noted, approximately 7 MW of demand was transferred from ERTS to HTS after commissioning of the new Keysborough zone substation in 2014-15. This is reflected in the diagram below.

The graph indicates that the forecast demand connected to the bus group ERTS (B34) is below its N rating for the full planning period. Therefore, it is not expected that the connected demand will exceed the total capacity of the bus group under normal operation at any time over the 10 year planning period.
Load remains below the “N-1” station rating under both 10th percentile and 50th percentile maximum demand forecasts for the ten year planning period. Load also remains below the N rating for both bus groups for the ten year planning period. Therefore, on the basis of the current forecasts, there is not expected to be any need for augmentation over the ten year planning period.
EAST ROWVILLE TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (61%) and AusNet Electricity Services (39%)
Station operational rating (N elements in service): 786 MVA via 4 transformers (Summer peaking)
Summer N-1 Station Rating: 573 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 656 MVA

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Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
FISHERMAN’S BEND TERMINAL STATION 66 kV (FBTS 66 kV)

FBTS 66 kV is a terminal station shared by both CitiPower (currently 93.5%) and Powercor (currently 6.5%). It is a summer critical station consisting of three 150 MVA 220/66 kV transformers supplying the Docklands areas and an area south-west of the City of Melbourne bounded by the Yarra River in the north and west, St Kilda/Queen’s Roads in the east and Hobsons Bay in the south. FBTS 66 kV is the main source of supply for 39,437 customers in areas of Docklands, Southbank, Port Melbourne, Fisherman’s Bend, Albert Park, Middle Park and St Kilda West.

As part of its asset renewal program, AusNet Transmission Group had planned to replace the B1 and B4 transformers with 2 x 150 MVA 220/66 kV transformer units by 2020. On 17 November 2016, the B1 transformer unit had an internal fault requiring it to be replaced permanently with a 150 MVA metropolitan spare transformer. The replacement is planned to be completed before the end of December 2016. CitiPower/Powercor has contingency plans in place to manage the load at risk in the interim period before the failed B1 transformer unit is replaced.

The peak load on the station reached 255.2 MW in summer 2016. It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.96.

Magnitude, probability and impact of loss of load

AEMO decided to retire the 125 MVA synchronous compensator at FBTS in 2015 and the station is now operating with all three 220/66 kV transformers in service under system normal conditions. Previously the station was run with one transformer operating on “Normal Open Auto Close” duty for fault level mitigation. AusNet Services has updated the terminal station ratings to reflect this change. The updated ratings shown in the graph below also reflect the permanent replacement of the failed B1 transformer unit with the metropolitan spare transformer as mentioned above.

The graph below depicts the 10th and 50th percentile maximum demand forecasts during the summer periods over the next ten years, together with the station’s operational N and N-1 ratings. The forecast demand includes the effects of any future load transfer works that have been committed.
The graph shows that there would be sufficient capacity at FBTS 66 kV to supply the forecast 50th percentile and 10th percentile demands over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
FRANKSTON TERMINAL STATION (FTS)

FTS is a 66 kV switching station. FTS was originally supplied from East Rowville terminal station (ERTS), and was transferred to Cranbourne terminal station (CBTS) in May 2005. The station is now supplied via three 66 kV supply routes from CBTS. There is one embedded generation unit over 1 MW connected at FTS 66 kV.¹

United Energy upgraded its existing CBTS-CRM 66 kV line in 2009. This increased the summer thermal rating of the line from 930 A to 1120 A at 35°C. There is a project currently underway to implement dynamic line ratings on the CBTS-FTS 66 kV double circuit tower lines using actual wind velocity, which is planned to be completed in 2017/18.

Arrangements relating to the ownership of assets supplying FTS, as well as the ratings of those assets are listed in the table below.

<table>
<thead>
<tr>
<th>66kV Supply Route to FTS</th>
<th>Thermal Rating @ 35°C</th>
<th>Dynamic Rating² @ 35°C</th>
<th>Ownership</th>
</tr>
</thead>
<tbody>
<tr>
<td>CBTS-FTS #1</td>
<td>825 Amp</td>
<td>825 Amp @ 1.2m/s</td>
<td>Transmission connection asset owned by AusNet Transmission Group</td>
</tr>
<tr>
<td></td>
<td></td>
<td>920 Amp @ 2.2m/s</td>
<td></td>
</tr>
<tr>
<td>CBTS-FTS #2</td>
<td>825 Amp</td>
<td>825 Amp @ 1.2m/s</td>
<td>Transmission connection asset owned by AusNet Transmission Group</td>
</tr>
<tr>
<td></td>
<td></td>
<td>920 Amp @ 2.2m/s</td>
<td></td>
</tr>
<tr>
<td>CBTS-CRM-(FTN/LWN)-FTS</td>
<td>1120 Amp</td>
<td>N/A</td>
<td>Distribution system assets owned by United Energy</td>
</tr>
</tbody>
</table>

Magnitude, probability and impact of loss of load

The various 66 kV supply routes and ownership arrangements mean that the risk assessment for FTS is more complicated than for other terminal stations. As far as transmission connection assets are concerned, load flow studies indicate that the lowest (N-1) rating of FTS during summer corresponds to the outage of CBTS-CRM 66 kV line which is limited by the combined thermal rating of CBTS-FTS No.1 and CBTS-FTS No.2 66 kV lines.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational (N-1) rating at 35°C as well as 40°C ambient temperature.

The (N-1) rating on the chart below indicates the maximum load that can be supplied from FTS with the CBTS-CRM 66 kV line out of service. If the CBTS-FTS 66 kV lines (owned and

¹ The maximum demand forecast adopted in this risk analysis excludes the impact of this embedded generation scheme.
² After implementing dynamic ratings in 2017/18.
operated by AusNet Transmission Group) become overloaded, AusNet Transmission Group’s automatic load shedding scheme would be initiated to trip both lines. This would result in loss of electricity supply to all customers connected at FTS until the lines are re-energised with a sufficiently reduced demand level to avoid further overloading.

The graph indicates that the 10th percentile overall summer maximum demand at FTS 66 kV is expected to exceed the (N-1) rating from summer 2023 while the 50th percentile summer maximum demand is forecast to exceed the station’s (N-1) rating at 40 °C from summer 2026.

The station load is forecast to have a power factor of 0.970 at times of peak demand. The demand at FTS is expected to exceed 95% of the 50th percentile peak demand for approximately 6 hours per annum.

The bar chart below depicts the energy at risk for the 10th percentile demand forecast, and the hours per year that the 10th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 10th percentile demand forecast.
Comments on Energy at Risk

For an outage of one of the CBTS-CRM 66 kV lines, there will be insufficient capacity at FTS to supply all the connected demand at the 10\textsuperscript{th} percentile temperature beyond 2023. AusNet Transmission Group will be implementing dynamic ratings for the CBTS-FTS 66 kV lines by 2018. This will eliminate the limitation at FTS until 2022. From summer 2023, to protect assets from overloading, a centralised automatic load shedding scheme (SOCS) at CBTS for the two CBTS-FTS 66 kV lines would be implemented to ensure that the loading of these two lines do not exceed their dynamic ratings. By the end of the ten year planning period, the total estimated duration of the constraint under N-1 is about 9 hours in 2026. The total energy at risk is estimated to be 4,105 MWh in summer 2026. The estimated value to consumers of the 4,105 MWh of energy at risk is approximately $141.3 million (based on a value of customer reliability of $34,410/MWh$).

The expected unavailability of CBTS-CRM 66kV sub-transmission line per annum due to a major outage is 0.0114\% per annum. When the energy at risk (4,105 MWh in 2026) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.5 MWh. This expected unserved energy is estimated to have a value to consumers of around $18,260 (based on a value of customer reliability of $34,410/MWh$).

If SOCS is not implemented to manage the loading of the two CBTS-FTS 66 kV lines below their dynamic ratings, AusNet Transmission Group will protect its assets by tripping both CBTS-FTS 66 kV lines. Hence there is a risk of the total supply to FTS being disconnected for an outage of the CBTS-CRM 66 kV line during high demand periods when the total connected load exceeds the N-1 rating.

The key statistics for the year 2026 under N-1 outage conditions are summarised in the table below. It is noted that after the dynamic ratings are implemented to the CBTS-FTS 66 kV

\[\text{The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.}\]
lines by 2018, the expected energy at risk is minimal within the 10 year planning period. Therefore no further works are anticipated.

<table>
<thead>
<tr>
<th></th>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
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</thead>
<tbody>
<tr>
<td>Energy at risk, at 50\textsuperscript{th} percentile demand forecast</td>
<td>0</td>
<td>$0.0 M</td>
</tr>
<tr>
<td>Expected unserved energy at 50\textsuperscript{th} percentile demand</td>
<td>0</td>
<td>$0.0 M</td>
</tr>
<tr>
<td>Energy at risk, at 10\textsuperscript{th} percentile demand forecast</td>
<td>4,105</td>
<td>$141.3 M</td>
</tr>
<tr>
<td>Expected unserved energy at 10\textsuperscript{th} percentile demand</td>
<td>0.5</td>
<td>$18,300</td>
</tr>
</tbody>
</table>
FRANKSTON TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (100%)
Normal cyclic rating with all plant in service: 273 MVA via all 66kV lines (Summer peaking)
Summer N-1 Loop Rating: 186 (199) MVA and 194 (207) MVA for an outage of CBTS-CRM and CBTS-FTS #1 or #2 lines [See Note 1]
Winter N-1 Loop Rating: 244 MVA and 201 MVA for an outage of CBTS-CRM and CBTS-FTS #1 or #2 lines respectively

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>171</td>
<td>170</td>
<td>170</td>
<td>170</td>
<td>172</td>
<td>174</td>
<td>177</td>
<td>182</td>
<td>186</td>
<td>191</td>
</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>138</td>
<td>141</td>
<td>144</td>
<td>146</td>
<td>148</td>
<td>150</td>
<td>152</td>
<td>155</td>
<td>158</td>
<td>161</td>
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<tr>
<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>184</td>
<td>183</td>
<td>183</td>
<td>183</td>
<td>185</td>
<td>188</td>
<td>192</td>
<td>196</td>
<td>202</td>
<td>207</td>
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<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
<td>140</td>
<td>144</td>
<td>147</td>
<td>149</td>
<td>151</td>
<td>153</td>
<td>156</td>
<td>159</td>
<td>162</td>
<td>165</td>
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<tr>
<td>N-1 energy at risk at 50th percentile demand (MWh)</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
</tr>
<tr>
<td>N-1 hours at risk at 50th percentile demand (hours)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
<td>378</td>
<td>913</td>
<td>2,342</td>
<td>4,105</td>
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<tr>
<td>N-1 hours at risk at 10th percentile demand (hours)</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>2</td>
<td>5</td>
<td>9</td>
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<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
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<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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</tr>
<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
<td>0.1</td>
<td>0.0</td>
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<td>0.0</td>
<td>0.0</td>
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</tr>
<tr>
<td>Expected Unserved Energy value at 50th percentile demand</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
<td>$5.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$1.5K</td>
<td>$3.8K</td>
<td>$10.0K</td>
</tr>
<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value</td>
<td>$1.5K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.0K</td>
<td>$0.4K</td>
<td>$1.1K</td>
<td>$3.0K</td>
<td>$5.5K</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
Geelong Terminal Station (GTS) 66 kV consists of four 150 MVA 220/66 kV transformers. Due to the excessive fault levels associated with all four transformers operating in parallel the following strategies have been adopted:

(a) Prior to 2012 the B3 transformer operated as a hot standby with a normally open auto close scheme on its 66 kV circuit breaker.

(b) In 2012 the 66 kV loop lines were rearranged so that the B3 transformer could be placed in service with the 66 kV bus tie circuit breaker between 66 kV buses 2&3 normally open. Under system normal, 66 kV buses 1&2 are supplied via B1 and B2 transformers and 66 kV buses 3&4 are supplied via B3 and B4 transformers. For loss of a transformer, the normally open 66 kV bus tie circuit breaker between buses 2&3 is closed. This measure increased the N capacity significantly as shown in the total station load forecast graph on page 4 of this risk assessment.

(c) As part of AusNet Transmission Group’s asset renewal program, the B3 transformer was replaced in 2013, and the B1 transformer was replaced in 2014. These works increased the terminal station’s capacity slightly as reflected in the total load forecast graph on page 4 of this risk assessment.

The GTS N-1 summer rating is now 524 MVA.

GTS is the main source of supply for over 145,832 customers in Geelong and the surrounding area. The station supply area includes Geelong, Corio, North Shore, Drysdale, Waurn Ponds and the Surf Coast.

Due to the operating arrangement at this station, load comparisons with the N rating are provided for the two separate bus groups below, followed by commentary on the total forecast demand at GTS and the station’s N-1 rating.

**GTS 1 & 2 66 kV Bus Group Summer Peak Forecasts**

This bus group supplies Powercor’s zone substations at Ford North Shore, Waurn Ponds, Colac and Winchelsea and 66 kV customer substations at Shell Refinery Corio and Blue Circle Cement

The peak load on the GTS 1 & 2 Bus group reached 172.6 MW (174.5 MVA) in summer 2016.

GTS 66 kV buses 1&2 demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service).
The (N) rating on the chart indicates the maximum load that can be supplied from GTS bus 1&2 with two transformers in service. The graph shows there is sufficient capacity (N rating) at the station to supply all expected load over the forecast period.

**GTS 3 & 4 66kV Bus Group Summer Peak Forecasts**

This bus group supplies Powercor's zone substations at Geelong East, Geelong City, Geelong B, Corio and 66 kV customer substation Ford Norlane.

The peak load on the GTS 3 & 4 Bus group reached 238.2 MW (245.9 MVA) in summer 2016.

GTS 66 kV buses 2&3 demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service).
The (N) rating on the chart indicates the maximum load that can be supplied from GTS bus 3&4 with two transformers in service. The graph shows there is sufficient capacity (N rating) at the station to supply all expected load over the forecast period.

**GTS Total Load Summer Peak Forecasts**

Growth in summer peak total demand at GTS has averaged around 2.7 MW (0.69 %) per annum over the last 5 years. The peak total load on the station reached 410.9 MW (419.9 MVA) in Summer 2016.

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.98.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.
The graph shows there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service under 50th and 10th percentile forecast conditions. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
GLENROWAN TERMINAL STATION 66 kV (GNTS 66 kV)

Glenrowan Terminal Station (GNTS) consists of one 125 MVA 220/66kV three phase transformer and one newly installed 150 MVA 220/66 kV three phase transformer that replaced the old 110 MVA transformer formed by six-single phase 55 MVA units in 2014.

The station is the main source of supply for a major part of north-eastern Victoria including Wangaratta in the north; to Euroa in the south; to Mansfield and Mt Buller in the east; and Benalla more centrally.

AusNet Electricity Services is responsible for planning the transmission connection and distribution networks for this region.

Magnitude, probability and impact of loss of load

GNTS has historically been a winter peaking station but more recently has had similar peak loading in summer and winter. The rate of growth in summer and winter peak demand at GNTS 66 kV has been low in recent years, and demand is forecast to continue to increase slowly at less than 1% per annum for the next few years.

The peak load on the station reached 98.8 MW (100.6 MVA) in winter 2015 and 103.1 MW (106.6 MVA) in summer 2015/16. The demand at GNTS 66 kV is expected to exceed 95% of the 50th percentile peak demand for 5 hours per annum. The station load has a power factor of 0.967 at summer maximum demand.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at an ambient temperature of 35°C.

The graph shows that there is no energy at risk under 50th percentile or 10th percentile loading conditions for the summer period for the next ten years. There is therefore not expected to be any need for augmentation over the ten year planning period.
HEATHERTON TERMINAL STATION (HTS)

HTS is the main source of supply for a major part of the southern metropolitan area. The geographic coverage of the HTS supply area spans from Brighton in the north to Edithvale in the south.

HTS is a summer critical terminal station. The station reached its highest recorded peak demand of 341.1 MW (351.4 MVA) in summer 2009 under extreme weather conditions. The recorded demand in summer 2016 was 331.7 MW (340 MVA), which was 49.1 MW higher than the 2015 peak. There are no embedded generation units over 1 MW connected at HTS.

Major works completed to manage load at HTS over the last eleven years have included establishment of a new terminal station at Cranbourne (CBTS) in 2005 to off-load HTS (and ERTS) prior to summer 2006. United Energy transferred approximately 48 MW away from HTS to CBTS in September 2005.

United Energy’s new Keysborough zone substation was commissioned in 2014. After commissioning, approximately 24 MW of demand was transferred from ERTS and SVTS to HTS. This load transfer is reflected in the graph below.

AusNet Transmission Group plans to replace the existing HTS 220/66 kV transformers in 2017 as part of their asset replacement programme. This is a committed project. The station ratings are expected to be marginally higher than current levels following the asset replacement as shown in the graph below. It should be noted however that the post-asset replacement station ratings used in this risk assessment are an estimate based on data from other similar stations. The ratings will be confirmed upon receipt of actual transformer test reports from the manufacturer.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.
The N rating on the graph indicates the maximum load that can be supplied from HTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that the 10th percentile maximum demand is expected to exceed the (N-1) rating from summer 2017 and 50th percentile maximum demand is expected to exceed the (N-1) rating from summer 2024.

The station load is forecast to have a power factor of 0.975 at times of peak demand. The demand at HTS is expected to exceed 95% of the 10th percentile peak demand for approximately 16 hours per annum.

The bar chart below depicts the energy at risk with one transformer out of service for the 10th percentile demand forecast, and the hours per year that the 10th percentile demand forecast is expected to exceed the (N-1) capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 10th percentile demand forecast.
Comments on Energy at Risk

For an outage of one transformer at HTS, it is expected that from 2017, there would be insufficient capacity at the station to supply all demand at the 10th percentile temperature.

By the end of the ten-year planning period in 2026, the energy at risk under N-1 conditions is estimated to be 124 MWh at the 10th percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 8 hours in that year. The estimated value to customers of the 124 MWh of energy at risk in 2026 is approximately $4.3 million (based on a value of customer reliability of $34,902/MWh). In other words, at the 10th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at HTS over the summer of 2026 would be anticipated to lead to involuntary supply interruptions that would cost consumers $4.3 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (124 MWh in 2026) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.8 MWh. This expected unserved energy is estimated to have a value to consumers of around $28,000 (based on a value of customer reliability of $34,902/MWh).

AusNet Transmission Group has indicated that all three of the transformers at HTS have an elevated failure rate due to the age and condition of the transformers. Therefore the expected unserved energy calculated above may underestimate the risk at this station. Given AusNet Transmission Group has plans in place to replace these transformers as part

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1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
of its asset replacement program in 2017, the elevated failure rates are unlikely to advance any augmentation requirement at this terminal station.\textsuperscript{2}

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of 10\textsuperscript{th} percentile temperatures occurring in each year. Under 50\textsuperscript{th} percentile temperature conditions, the energy at risk in 2026 is estimated to be 10 MWh. The estimated value to consumers of this energy at risk in 2026 is approximately $0.4 million. The corresponding value of the expected unserved energy (0.1 MWh) is around $2,300.

These key statistics for the year 2026 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
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<td>$0.4 million</td>
</tr>
<tr>
<td>0.1</td>
<td>$2,300</td>
</tr>
<tr>
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<td>$4.3 million</td>
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<tr>
<td>0.8</td>
<td>$28,000</td>
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</tbody>
</table>

**Possible impacts of a transformer outage on customers**

If one of the 220/66 kV transformers at HTS is taken off line during peak loading times and the (N-1) station rating is exceeded, the OSSCA\textsuperscript{3} load shedding scheme which is operated by AusNet Transmission Group’s TOC\textsuperscript{4} will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy’s operational procedures after the operation of the OSSCA scheme.

In the case of HTS supply at maximum loading periods, the OSSCA scheme would shed about 160 MVA of load, affecting approximately up to 42,420 customers in 2017.

**Feasible options for alleviation of constraints**

As already noted, AusNet Transmission Group intends to replace the existing HTS ‘B’ transformers in 2017 with like-for-like transformers. This is a committed project. The station’s (N-1) rating after asset replacement is expected to be marginally higher than the current level. However the final ratings are subject to confirmation upon receipt of actual transformer test reports from the manufacturer.


\textsuperscript{3} Overload Shedding Scheme of Connection Asset.

\textsuperscript{4} Transmission Operations Centre
In addition to the committed transformer replacement works, the following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy has established and implemented the necessary plans that enable load transfers under contingency conditions, via both 66 kV subtransmission and 22/11 kV distribution networks. These plans are reviewed annually prior to the summer season. Transfer capability away from HTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 72 MVA for summer 2016-17.

2. Install a fourth 220/66 kV transformer at HTS.

3. Establish a new 220/66 kV terminal station (DNTS) in the Dandenong area to off-load HTS.

Prior to 2011, the TCPR identified that a 4th transformer at HTS would be the preferred network option to alleviate the increasing load at risk. It has now been determined that this may not be the most economic option for the following reasons:

- HTS is supplied on a radial double-circuit 220 kV transmission line from Rowville (ROTS) via Springvale (SVTS). The connected demand on these lines is presently reliant on emergency short time ratings to remain within the N-1 rating of the 220 kV circuits. Therefore the capacity provided by a fourth transformer at HTS may not be able to be utilised because of the 220 kV line constraints.

- The anticipated timing of a 4th transformer at HTS coincides with a number of other significant sub-transmission and connection asset constraints in the Dandenong, Keysborough and Braeside areas, which a 4th transformer at HTS would not be able to resolve.

In early 2012 United Energy submitted a preliminary connection enquiry to AEMO for the establishment of a new connection point in the Dandenong area. Joint planning activities have been underway between the two organisations to quantify the risk of the emerging constraints in the area and to assess viable options for alleviating the constraints. The investigations to date have identified that the need is driven mainly by load-at-risk associated with the 220 kV line constraints in the area. Utilising United Energy’s latest maximum demand forecasts, this assessment indicates that the establishment of a new Dandenong Terminal Station (DNTS) with associated sub-transmission works is not likely to be economically justified within the ten year planning horizon.

The capital cost of installing a new 220/66 kV terminal station in Dandenong and related subtransmission works is estimated to be in excess of $70 million. The cost of establishing, operating and maintaining the new assets would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $7 million.

Further analysis, including a Regulatory Investment Test for Transmission will be undertaken at a later time to determine the preferred option for addressing the constraints, but at this stage a new 220/66 kV terminal station in Dandenong is the planned network option to address the emerging constraints. United Energy will continue to work with AEMO on this joint planning exercise.
Preferred network option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at HTS, it is proposed to:

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at HTS under critical loading conditions:
   - maintain contingency plans to transfer load quickly to adjacent terminal stations;
   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place; and
   - subject to the availability of AusNet Transmission Group’s spare 220/66 kV transformer for metropolitan areas (refer to Section 5.5), this spare transformer can be used to temporarily replace a failed transformer.

2. Replace the existing HTS ‘B’ transformers in 2017 as part of AusNet Transmission Group’s asset replacement programme.

3. Establish a new 220/66 kV terminal station in the Dandenong area to off-load HTS. On the present forecasts, the new terminal station in the Dandenong area is unlikely to be economic within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
HEATHERTON TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (100%)

Station operational rating (N elements in service):
- Summer N-1 Station Rating: 537 MVA via 3 transformers (Summer peaking)
- Winter N-1 Station Rating: 406 MVA

<table>
<thead>
<tr>
<th></th>
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<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
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<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.01M</td>
<td>$0.01M</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
HORSHAM TERMINAL STATION (HOTS) 66kV

Horsham Terminal Station (HOTS) 66 kV consists of two 100 MVA 235/67.5 kV transformers and is the main source of supply for some 36,933 customers in Horsham and the surrounding area. The station supply area includes Horsham, Edenhope, Warracknabeal and Nhill. The station also supplies Stawell via the inter-terminal 66 kV ties with Ballarat Terminal Station (BATS).

Magnitude, probability and impact of loss of load

HOTS 66 kV demand has recently become winter peaking. Winter peak demand at HOTS has increased by an average of around 2.7 MW (3.9 %) per annum over the last 5 years. The peak load on the station reached 83.6 MW (83.6 MVA) in winter 2015.

It is estimated that:

- For 3 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is unity.

The graph depicts the 10th and 50th percentile winter maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 5°C ambient temperature.

The graph shows there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service under 50th and 10th percentile forecast conditions. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
**HEYWOOD TERMINAL STATION (HYTS) 22 kV**

Heywood Terminal Station (HYTS) 22 kV consists of two 70 MVA 500/275/22 kV transformers and is the source of supply to an industrial customer in the local area and the only large customer supplied from this supply point. Another 177 small domestic and farming customers along the line route are also supplied from this supply point.

**Magnitude, probability and impact of loss of load**

The peak load on the station reached 1.8 MW (1.9 MVA) in summer 2016.

The 22 kV point of supply was established in late 2009, by utilising the tertiary 22 kV on the existing 2 x 500/275/22 kV South Australian / Victorian interconnecting transformers. The supply is arranged so that one transformer is on hot standby (on its tertiary 22 kV), due to excessive fault levels.

It is estimated that:

- For 1 hour per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of peak demand is 0.96.

The graph depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N-1” rating at 35°C ambient temperature.

The graph shows that there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
KEILOR TERMINAL STATION 66 kV (KTS 66 kV)

Keilor Terminal Station is located in the north west of Greater Melbourne. It operates at 220/66 kV and supplies a total of approximately 220,000 Jemena Electricity Networks and Powercor customers in the Airport West, St. Albans, Sunshine, Melton, Woodend, Pascoe Vale, Essendon and Braybrook areas.

Background

KTS has five 150 MVA transformers and is a summer critical station. Up until 2012, the station was operated with one of the five transformers, also known as KTS B5 transformer, in “hot standby” mode, with the then No. 2-3 66 kV bus tie circuit breaker open for the purpose of limiting the maximum prospective fault levels to within switchgear ratings. In the event of an outage of one of the four “normally on-load” transformers, the B5 unit would be connected in automatically. Therefore the “N” and “N-1” ratings were the same.

In 2012, the station was re-configured to enable the KTS B5 transformer to take load under system normal conditions. Under system normal conditions, the No.1, No.2 & No.5 transformers are operated in parallel as one group (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 group (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, the No.5 transformer will automatically change over 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. Given this configuration, load demand on the KTS(B3,4) group must be kept within the capabilities of the two transformers at all times or load shedding will occur.

The following sections examine the two transformer groups separately.

Transformer group KTS (B1,2,5) Summer Peak Forecasts

The graph below depicts the KTS (B1,2,5) rating with all transformers (B1, B2 & B5) in service (“N” rating), and with one of the three transformers out of service (“N-1” rating), along with the 50\(^{th}\) and 10\(^{th}\) percentile summer maximum demand forecasts\(^{1}\).

The peak load on the station reached 387.4 MW (or 387.8 MVA) in summer (February) 2016. It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50\(^{th}\) percentile demand forecast.
- The station transformer load power factor at time of peak demand is 0.99.

\(^{1}\) Note that station transformer output capability rating and transformer loading are shown in the graph.
The new Deer Park Terminal Station (DPTS) is expected to be established by late 2017 and will off-load KTS (B125) group. The transfer of load from KTS to DPTS is reflected in the load forecasts shown above.

The above graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand for the entire forecast period. However, if there is a forced transformer outage during peak load periods, some customers would be affected.

**Transformer group KTS (B3,4) Summer Peak Forecasts**

The graph below depicts the summer maximum demand forecasts (for 50th and 10th percentile temperatures) for KTS (B3,4) and the corresponding rating with both transformers (B3 & B4) operating.

The peak load on the station reached 266.2 MW (or 279.8MVA) in summer 2016 (December 2015).

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer load power factor at time of peak demand is 0.95.

It shows that with all transformers in service, there will be sufficient capacity to meet the anticipated maximum load demand for the entire forecast period. The new Deer Park Terminal Station is expected to be established in 2018 and will off-load KTS (B34) group.

As explained above, if an unplanned transformer outage in the KTS(B3,4) group occurs, the No.5 transformer will automatically change over to the KTS(B3,4) group. In effect, the N-1
and N ratings of the KTS(B3,4) group are equivalent. Thus the load at risk level under a transformer outage condition is equivalent to the load at risk under system normal conditions.

**Magnitude, probability and impact of loss of load at KTS**

The magnitude, probability and load at risk for the two transformer groups are considered together below.

**System Normal Condition (All 5 transformers in service)**

At the 50th percentile level, the demand forecast is expected to be below the N capability rating, and therefore there is no load at risk for the entire forecast period. However it should be noted that the demand forecast incorporates load transfer to the new Deer Park Terminal Station in 2018.

**N-1 System Condition**

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating for the KTS(B1,2,5) group. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.
Comments on Energy at Risk at KTS

With the establishment of Deer Park Terminal Station expected to be completed before summer 2017/18, there will be sufficient capacity at KTS 66 kV to supply all customer demand for the entire forecast period under system normal conditions. After Deer Park Terminal Station is established in 2017, there would also be sufficient capacity at the station to supply all customer demand under an outage of one transformer at KTS 66 kV until 2026 for demand below the 50th percentile demand forecast.

In summer 2016/17, the energy that would not be supplied under a transformer outage (N-1) condition on the KTS transformer groups is estimated to be 894.6 MWh for the 50th percentile demand forecast. Over the summer 2016/17 period, there would be insufficient capacity to meet demand for about 41 hours in that year for (N-1) condition. The estimated value to consumers of the 894.6 MWh of the energy not supplied is approximately $35.3 million (based on a value to customer reliability of $39,400/ MWh). In other words, at the 50th percentile summer demand level, and in the absence of any other operational response that might be taken to mitigate impacts on customers, a major outage of one transformer at KTS over the summer of 2016/17 would be anticipated to lead to involuntary supply interruptions that would cost consumers $35.3 million.

It is emphasised however, that the probability of a major outage of one of the five transformers is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (894.6 MWh) is weighted by this low transformer unavailability, the expected unserved energy (for loss of one transformer) is estimated to be around 9.7 MWh. The expected unserved energy is estimated to have a value to consumers of around $382,000.

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2 The value of unserved energy is derived from the sector values given in Table 1 in Section 2.4, weighted in accordance with the composition of the load at this terminal station.
It should also be noted that the above estimates are based on an assumption of demand up to the average (50th percentile) summer temperatures occurring in each year. Under 10th percentile summer temperature conditions, the customer demand increases significantly due to air conditioning loads. At the 10th percentile demand forecast, the amounts of energy that would not be supplied in the summer of 2016/17 for N and (N-1) conditions are estimated to be 0.1 MWh and 4,037 MWh respectively. The estimated value to consumers of this energy in the summer of 2016/17 for N and (N-1) conditions is approximately $4,500 and $159.2 million respectively. The total corresponding value of the expected unserved energy (43.8 MWh in summer 2016/17) is approximately $1.7 million.

These key statistics for the summer of 2016/17 under N and (N-1) outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
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<tbody>
<tr>
<td>Energy not supplied at 50th percentile demand forecast under N condition</td>
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</tr>
<tr>
<td>Energy at risk, at 50th percentile demand forecast under N-1 outage condition</td>
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<td>Expected unserved energy at 50th percentile demand under N-1 outage condition</td>
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<td>Total expected unserved energy at 50th percentile demand for N and N-1 conditions</td>
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<td>Energy not supplied at 10th percentile demand forecast under N condition</td>
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<td>Energy at risk, at 10th percentile demand forecast under N-1 outage condition</td>
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<td>Expected unserved energy at 10th percentile demand under N-1 outage condition</td>
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<tr>
<td>Total expected unserved energy at 10th percentile demand for N and N-1 conditions</td>
<td>43.8</td>
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Possible Impacts on Customers

System Normal Condition (All 5 transformers in service)

Applying the 50th percentile demand forecast, and assuming that Deer Park Terminal Station is completed before summer 2017/18, there will be sufficient capacity at the station to supply all customer demand for the entire forecast period under system normal condition.
N-1 System Condition

If one of the KTS 220/66 kV transformers is taken off line during peak loading times, causing the KTS (B1,2,5) rating to be exceeded, the OSSCA\(^3\) load shedding scheme which is operated by AusNet Transmission Group’s TOC\(^4\) will act swiftly to reduce the loads in blocks to within transformer capabilities. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored after the operation of the OSSCA scheme, at zone substation feeder level in accordance with Jemena Electricity Networks’ and Powercor’s operational procedures.

In the summer of 2016/17, at maximum loading periods, based on the Schedule of Priority Load Shedding recommended by the Demand Reduction Committee, the OSSCA scheme would automatically shed about 66 MVA of the KTS supply load at the 50\(^{th}\) percentile demand forecast. This would affect approximately 22,000 customers. The corresponding energy at risk is 895 MWh.

After the establishment of Deer Park Terminal Station (which is expected to be completed in 2017), the energy at risk and expected unserved energy reduces significantly, alleviating this emerging constraint.

**Feasible options and preferred network option(s) for alleviation of constraints**

The risk of supply interruption at Keilor Terminal Station (KTS) has previously been assessed as being very high for summer 2017/18\(^5\). The proposed network option that was identified by both Powercor and Jemena Electricity Networks (in the 2010 and 2011 Transmission Connection Planning Reports) as the most economic network solution is to:

- establish a new 220/66 kV terminal station at Deer Park and associated 66 kV subtransmission lines by summer 2017/18; and
- to transfer load from KTS(B1,2,5) and KTS(B3,4) groups to the new terminal station.

Powercor and Jemena Electricity Networks completed a public “Expression of Interest” process for non-network alternatives, via the publication of the Transmission Connection Planning Reports in 2010 and 2011. In 2011, Powercor and Jemena Electricity Networks also provided potential proponents of non-network solutions with information on capacity constraints at KTS, supply risks and potential opportunities for provision of network support services. Early in 2012, Powercor, Jemena and AEMO completed a Joint Consultation Paper\(^6\) and Joint Regulatory Test Report\(^7\) in relation to the options for addressing the capacity constraints at KTS. A copy of the report is available at:


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\(^3\) Overload Shedding Scheme of Connection Asset.  
\(^4\) Transmission Operations Centre.  
\(^5\) The risk of supply interruptions at KTS had been assessed as being unacceptable for summer 2016/17 in the 2010 and 2011 Transmission Connection Planning Reports. However, in light of the updated forecasts published in 2012, 2013 and 2014, the revised optimal timing for the proposed network solution was determined to be prior to summer 2017/18, based on an investment decision rule of maximising expected net market benefits. Commitments were subsequently made to proceed with the project, which is now nearing completion.  
\(^6\) The Joint Consultation Paper was published on Jemena, Powercor and AEMO websites on 10 February 2012.  
\(^7\) The Joint Regulatory Test Report was published on Jemena, Powercor and AEMO websites on 1 May 2012.
At the conclusion of the expression of interest and regulatory consultation process on 27 July 2012, no firm proposals for alternatives to the network augmentation had been received.

In the absence of any commitment by interested parties to offer non-network solutions, Powercor and Jemena Electricity Networks have proceeded with the next stage of the process by implementing the proposed network solution - that is, establishing a new 220/66 kV terminal station at Deer Park and associated 66 kV sub-transmission lines by summer 2017/18 at an estimated capital cost of $125 million, to transfer load from KTS(B1,2,5) and KTS(B3,4) groups to the new terminal station. Deer Park Terminal Station is a committed project and is presently being constructed.

In the meantime, the risk to supply reliability will be mitigated through the following temporary measures:

- Balance the load between the two bus groups at KTS so that the load on each bus group is kept below its N rating;

- Maintain contingency plans to transfer load quickly, where possible, to adjacent terminal stations. Powercor and Jemena Electricity Networks have established and implemented the necessary plans that enable up to 80 MVA of load transfers via existing 22 kV feeders to adjacent terminal stations. This option is able to partly reduce the interruption duration and load at risk resulting from a major transformer failure;

- Fine-tune the OSSCA scheme settings in conjunction with AusNet Transmission Group to minimise the impact on customers of any automatic load shedding that may take place; and

- Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for urban areas (refer to section 5.5), a spare transformer could be installed at KTS and used to temporarily replace a failed transformer.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
KEILOR TERMINAL STATION (KTS(B1,2,5) TRANSFORMER GROUP)

Detailed data: Magnitude and probability of loss of load

| Distribution Businesses supplied by this station: | Jemena EN (59%), Powercor (41%) |
| Normal cyclic rating with all plant in service | 509 MVA at 50th percentile temperature and 490 MVA at 10th percentile temperature (Summer peaking) |
| Summer N-1 Station Transformer Rating: | 339 MVA at 50th percentile temperature and 327 MVA at 10th percentile temperature [See Note 1 below for interpretation of N-1] |
| Winter N-1 Station Transformer Rating: | 353 MVA |

<table>
<thead>
<tr>
<th>Station: KTS(B125) 66kV</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>405.1</td>
<td>307.4</td>
<td>312.7</td>
<td>318.1</td>
<td>318.8</td>
<td>322.4</td>
<td>329.7</td>
<td>333.8</td>
<td>340.7</td>
<td>344.6</td>
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<tr>
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<td>314.5</td>
<td>240.6</td>
<td>247.6</td>
<td>255.3</td>
<td>257.3</td>
<td>263.9</td>
<td>272.4</td>
<td>278.2</td>
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<td>341.3</td>
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<td>367.1</td>
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<td>250.3</td>
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<td>265.4</td>
<td>267.8</td>
<td>274.7</td>
<td>283.4</td>
<td>289.4</td>
<td>299.2</td>
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<td>N-1 energy at risk at 10th percentile demand (MWh)</td>
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<td>133</td>
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<td>479</td>
<td>590</td>
<td>814</td>
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<td>N-1 hours at risk at 10th percentile demand (hours)</td>
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<td>14</td>
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<td>23</td>
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<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
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<td>0.6</td>
<td>1.4</td>
<td>2.4</td>
<td>2.6</td>
<td>3.7</td>
<td>5.2</td>
<td>6.4</td>
<td>8.8</td>
<td>9.7</td>
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<tr>
<td>Expected Unserved Energy value at 50th percentile demand</td>
<td>$0.4 M</td>
<td>$- M</td>
<td>$- M</td>
<td>$- M</td>
<td>$- M</td>
<td>$- M</td>
<td>$- M</td>
<td>$- M</td>
<td>$0.0 M</td>
<td>$0.0 M</td>
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<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
<td>$1.7 M</td>
<td>$0.0 M</td>
<td>$0.1 M</td>
<td>$0.1 M</td>
<td>$0.1 M</td>
<td>$0.1 M</td>
<td>$0.2 M</td>
<td>$0.3 M</td>
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<td>$0.4 M</td>
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<tr>
<td>Expected Annual Unserved Energy value (using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value)</td>
<td>$0.8 M</td>
<td>$0.0 M</td>
<td>$0.0 M</td>
<td>$0.0 M</td>
<td>$0.0 M</td>
<td>$0.0 M</td>
<td>$0.1 M</td>
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<td>$0.1 M</td>
<td>$0.1 M</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station transformer output capability rating with outage of one transformer. The rating is at an ambient temperature of 38.5 degrees Centigrade and 42 degrees Centigrade (for 50th percentile value and 10th percentile value respectively) as this is the typical temperatures where 50% PoE loads and 10% PoE loads are likely to occur at KTS.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx).

Note that risk assessment for this station is carried out using station transformers’ rating and loading.
KEILOR TERMINAL STATION (KTS(B3,4) TRANSFORMER GROUP)

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Jemena EN (29%), Powercor (71%)
Normal cyclic rating with all plant in service: 321 MVA at 50\textsuperscript{th} percentile temperature and 311 MVA at 10\textsuperscript{th} percentile temperature (Summer peaking)
Summer N-1 Station Transformer Rating: 321 MVA at 50\textsuperscript{th} percentile temperature and 311 MVA at 10\textsuperscript{th} percentile temperature [See Note 1 below for interpretation of N-1]

Winter N-1 Station Transformer Rating: 344 MVA

<table>
<thead>
<tr>
<th>Station: KTS(B34) 66kV</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>50\textsuperscript{th} percentile Summer Maximum Demand (MVA)</td>
<td>273.0</td>
<td>204.2</td>
<td>205.9</td>
<td>206.7</td>
<td>208.3</td>
<td>209.2</td>
<td>212.4</td>
<td>214.8</td>
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<tr>
<td>50\textsuperscript{th} percentile Winter Maximum Demand (MVA)</td>
<td>230.7</td>
<td>168.8</td>
<td>171.7</td>
<td>175.0</td>
<td>176.5</td>
<td>179.3</td>
<td>183.0</td>
<td>185.3</td>
<td>188.9</td>
<td>193.4</td>
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<tr>
<td>10\textsuperscript{th} percentile Summer Maximum Demand (MVA)</td>
<td>311.1</td>
<td>233.4</td>
<td>235.3</td>
<td>236.2</td>
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<td>241.7</td>
<td>244.4</td>
<td>248.6</td>
<td>250.8</td>
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<tr>
<td>10\textsuperscript{th} percentile Winter Maximum Demand (MVA)</td>
<td>249.6</td>
<td>186.7</td>
<td>189.9</td>
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<td>198.0</td>
<td>201.9</td>
<td>204.3</td>
<td>208.0</td>
<td>212.9</td>
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<td>N-1 energy at risk at 50\textsuperscript{th} percentile demand (MWh)</td>
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<td>N-1 hours at risk at 50\textsuperscript{th} percentile demand (hours)</td>
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</tr>
<tr>
<td>N-1 energy at risk at 10\textsuperscript{th} percentile demand (MWh)</td>
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<td>-</td>
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<tr>
<td>N-1 hours at risk at 10\textsuperscript{th} percentile demand (hours)</td>
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<td>-</td>
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</tr>
<tr>
<td>Expected Unserved Energy at 50\textsuperscript{th} percentile demand (MWh)</td>
<td>-</td>
<td>-</td>
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<td>-</td>
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</tr>
<tr>
<td>Expected Unserved Energy at 10\textsuperscript{th} percentile demand (MWh)</td>
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<td>-</td>
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</tr>
<tr>
<td>Expected Unserved Energy value at 50\textsuperscript{th} percentile demand</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
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</tr>
<tr>
<td>Expected Unserved Energy value at 10\textsuperscript{th} percentile demand</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
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<td>$\cdot M$</td>
<td>$\cdot M$</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy value (using AEMO weighting of 0.7 x 50\textsuperscript{th} percentile value + 0.3 x 10\textsuperscript{th} percentile value)</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
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<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
<td>$\cdot M$</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station transformer output capability rating with outage of one transformer. The rating is at an ambient temperature of 38.5 degrees Centigrade and 42 degrees Centigrade (for 50\textsuperscript{th} percentile value and 10\textsuperscript{th} percentile value respectively) as this is the typical temperatures where 50\% PoE loads and 10\% PoE loads are likely to occur at KTS.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is the same as “N-1 energy at risk” for this bus group.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) is the same as “N-1 hours per year at risk” for this bus group.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50\textsuperscript{th} and 10\textsuperscript{th} percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx).

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Note that risk assessment for this station is carried out using station transformers’ rating and loading.
KERANG TERMINAL STATION (KGTS) 66kV & 22kV

Kerang Terminal Station (KGTS) 66 kV and 22 kV consists of three 35 MVA 235/66/22 kV transformers and is the main source of supply for over 18,008 customers in Kerang and the surrounding area. The station supply area includes Kerang, Swan Hill and Cohuna.

Magnitude, probability and impact of loss of load

Growth in summer peak demand at KGTS has averaged around 1.4 MVA (1.52%) per annum over the last 5 years. The peak load on the station reached 70.3 MW (66 kV and 22 kV networks) in summer 2016.

It is estimated that:

- For 6 hours per year, 95% of peak demand is expected to be reached under the 50\(^{th}\) percentile demand forecast.
- The station load power factor at the time of peak demand is 0.97.

KGTS 22 & 66 kV demand is summer peaking. The graph below depicts the 10\(^{th}\) and 50\(^{th}\) percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.

The graph shows there is sufficient capacity at the station to supply all expected demand at the 50\(^{th}\) percentile temperature, over the forecast period, even with one transformer out of service. Load at risk after 2025 for the 10\(^{th}\) percentile demand scenario can be managed by transferring load to Red Cliffs Terminal Station and Wemen Terminal Station. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
MALVERN 22 kV TERMINAL STATION (MTS 22 kV)

MTS 22 kV is the source of supply for over 12,000 customers in Burwood, Ashwood, Glen Iris, Mount Waverley and Surrey Hills.

The station underwent a refurbishment in 2007 when the asset owner, AusNet Transmission Group, replaced aged transformers and switchgear including protection and control equipment at the station. The project was part of AusNet Transmission Group’s asset replacement program, and included replacement of the three old 45/55 MVA 220/22 kV transformers with two new 40/60 MVA 66/22 kV transformers. These transformers are supplied from existing 140/225 MVA 220/66 kV transformers at MTS (refer also to the Risk Assessment for MTS 66 kV).

In addition to asset replacement works at MTS 22 kV by AusNet Transmission Group, two major 22 kV to 66 kV conversion projects initiated by United Energy (UE) on its network, resulted in load transfers from MTS 22 kV to MTS 66 kV being commenced in 2001. The reduction in MTS 22 kV summer maximum demand from 89.3 MVA in 2001 to 34.5 MVA in 2011, shown in the graph below, is attributed to the conversion works by UE.

MTS 22 kV is a summer critical terminal station. The recorded demand in summer 2016 was 40.1 MW (40.6 MVA), which was approximately 3.6 MW higher than the summer 2015 peak. The station load has a power factor of 0.986 at times of peak demand.

There are no embedded generation units over 1 MW connected at MTS 22 kV.

**Magnitude, probability and impact of loss of load**

In addition to historical summer maximum demands, the graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.
The N rating on the graph indicates the maximum load that can be supplied from MTS 22 kV with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph above shows that with one transformer out of service, the demand at MTS 22 kV will remain well within the (N-1) station rating over the next ten years.

The station load is forecast to have a power factor of 0.983 at times of peak demand. The demand at MTS 22 kV is expected to exceed 95% of the 50th percentile peak demand for approximately 5 hours per annum.

On the basis of the current forecasts, the need for augmentation of transmission connection assets at MTS 22 kV is not expected to arise over the next decade.

The table on the following page provides more detailed data on the station rating and demand forecasts.
MALVERN TERMINAL STATION 22 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy Distribution (100%)
Station operational rating (N elements in service): 152 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating: 76 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 84 MVA

<table>
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<tr>
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<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
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<td>50th percentile Winter Maximum Demand (MVA)</td>
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<td>29.3</td>
<td>29.4</td>
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<td>10th percentile Summer Maximum Demand (MVA)</td>
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<tr>
<td>N-1 hours at risk at 50th percentile demand (hours)</td>
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<tr>
<td>N-1 energy at risk at 10th percentile demand (MWh)</td>
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<td>0</td>
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<tr>
<td>N-1 hours at risk at 10th percentile demand (hours)</td>
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<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
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<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
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<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
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<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value</td>
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</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
MALVERN 66 kV TERMINAL STATION (MTS 66 kV)

MTS 66 kV is the main source of supply for over 75,000 customers in Elsternwick, Caulfield, Carnegie, Malvern East, Ashburton, Chadstone, Oakleigh, Ormond, Murrumbeena, Hughesdale and Bentleigh East.

The station underwent a refurbishment in 2007 when the asset owner, AusNet Transmission Group, replaced aged transformers and switchgear including protection and control equipment at the station. The project was part of AusNet Transmission Group’s asset replacement program, and included replacement of the three old 45/55 MVA 220/66 kV transformers with two new 140/225 MVA 220/66 kV transformers. These transformers support the demand of both 66 kV and 22 kV networks ex MTS (refer also to the Risk Assessment for MTS 22 kV).

MTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 220 MW (226 MVA) in summer 2009 under extreme weather conditions. The recorded demand in summer 2016 was 204.6 MW (207.2 MVA), which was approximately 93% of the recorded historic maximum demand.

There are no embedded generation units over 1 MW connected at MTS 66 kV.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.

![MTS 66kV Summer Peak Forecasts](image)

The N rating on the graph indicates the maximum load that can be supplied from MTS 66 kV with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.
The graph above shows that with one transformer out of service, the demand at MTS 66 kV will remain well within the (N-1) station rating over the next ten years.

The station load is forecast to have a power factor of 0.987 at times of peak demand. The demand at MTS 66 kV is expected to exceed 95% of the 50\textsuperscript{th} percentile peak demand for approximately 4 hours per annum.

On the basis of the latest forecasts, the need for augmentation of transmission connection assets at MTS 66 kV is not expected to arise over the next decade.

The table on the following page provides more detailed data on the station rating and demand forecasts.
MALVERN TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy Distribution (100%)
Station operational rating (N elements in service): 526 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating: 263 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 303 MVA

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<td>163</td>
<td>164</td>
<td>165</td>
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<td>0</td>
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<tr>
<td>N-1 hours at risk at 50th percentile demand (hours)</td>
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<td>0</td>
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<tr>
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<td>0.0</td>
<td>0.0</td>
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<td>0.0</td>
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<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
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<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
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<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value</td>
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<td>$0.0k</td>
<td>$0.0k</td>
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</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
MORWELL TERMINAL STATION 66 kV (MWTS 66 kV)

Morwell Terminal Station (MWTS) 66 kV is the main source of supply for a major part of south-eastern Victoria including Gippsland. It supplies Phillip Island, Wonthaggi and Leongatha in the west; Moe and Traralgon in the central area; to Omeo in the north; and to Bairnsdale and Mallacoota in the east.

AusNet Electricity Services is responsible for the transmission connection and distribution network planning for this region.

Magnitude, probability and impact of loss of load

MWTS 66 kV is supplied by two 150 MVA 220/66 kV transformers and one 165 MVA 220/66 kV transformer.

MWTS 66 kV is a summer peaking station and recorded a maximum demand of 452 MW (464 MVA) in early January 2013. The peak demand on the station reached 441 MW (453 MVA) in summer 2015/16. The 2015/16 station peak demand is lower than the 2012/13 station peak demand due to relatively mild weather conditions experienced in summer 2015/16. The peak demand period is usually quite short, and coincides with a few weeks of peak tourism from Christmas to early January along the east coast of Victoria. The maximum demand recorded is very dependent on weather conditions during this short period. The load at MWTS 66 kV is forecast to decline at a rate of around 0.3% per annum for the next ten years. The station load has a power factor of 0.975 at maximum demand. MWTS 66 kV demand is expected to exceed 95% of the 50th percentile peak demand for 5 hours per annum.

The assessment of the energy at risk at MWTS 66 kV needs to take into account the significant levels of embedded generation which is connected to the MWTS 66 kV bus, which directly offsets the loading on the 220/66 kV transformers at MWTS. The embedded generation includes the 80 MW Bairnsdale Power Station (BPS), the 10 MW Traralgon Power Station, the Wonthaggi and Toora Wind Farms totalling 33 MW and the new 106 MW Bald Hill Wind Farm. Bald Hills Wind Farm commenced operation in early 2015. The combined capacity of all of these embedded generators totals 229 MW. During the summer 2015/16 peak demand a total generation contribution of 65 MW was observed from the above embedded generators. In order to make a realistic assessment of the risk at MWTS the total output from these embedded generators is assumed to be 60 MVA.

The “N–1” and “N” ratings shown on the graph below include the transformer capacity as well as the assumed 60 MVA contribution from embedded generation. For example the 395 MVA “N–1” rating includes the 335 MVA capacity of two 220/66 kV transformers and 60 MVA from embedded generation. The graph also shows the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service plus 60 MVA from embedded generation) and the “N-1” rating at an ambient temperature of 35°C. The “N” rating on the chart indicates the maximum load that can be supplied from MWTS 66 kV with all transformers in service. Summer peak demand loading at MWTS is expected to exceed the station’s “N-1” rating for the entire planning period between 2016/17 to 2025/26.
The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the “N-1” capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

MWTS is not expected to be loaded above its “N-1” rating under 50th percentile or 10th percentile winter maximum demand forecasts during the 10 year planning horizon.
Comments on Energy at Risk

As noted above, embedded generation is expected to be contributing 60 MVA over the peak demand period so the analysis below assumes this level of embedded generation output, although the total available capacity of the embedded generators is 229 MVA.

For an outage of one transformer at MWTS 66 kV over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for approximately 1 hour in 2016/17. The corresponding energy at risk under “N-1” conditions is estimated to be approximately 5 MWh. The estimated value to consumers of this energy at risk is approximately $0.21 million (based on a value of customer reliability of $38,391/MWh)\(^1\). It is noted, however, that the probability of a major outage of one of the three transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (5 MWh for summer 2016/17) is weighted by this low unavailability, the expected unsupplied energy is negligible.

Due to declining forecast demand, the energy at risk at the 50th percentile forecast under “N-1” conditions is estimated to reduce over the ten year planning period, and has been assessed to be negligible by the end of the planning period (summer 2025/26).

Under higher summer temperature conditions (that is at the 10th percentile level), the energy at risk in 2016/17 is estimated to be 461 MWh. The estimated value to consumers of the energy at risk is $17.7 million. When this energy at risk is weighted by the transformer unavailability, the expected unserved energy is estimated to be 3 MWh, which has a value to consumers of around $0.12 million.

These key statistics for the year 2016/17 under “N-1” outage conditions are summarised in the table below.

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<tr>
<th></th>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
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<tbody>
<tr>
<td>Energy at risk at 50th percentile demand forecast</td>
<td>5</td>
<td>$0.21</td>
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<tr>
<td>Expected unserved energy at 50th percentile demand</td>
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<tr>
<td>Energy at risk at 10th percentile demand forecast</td>
<td>461</td>
<td>$17.7 million</td>
</tr>
<tr>
<td>Expected unserved energy at 10th percentile demand</td>
<td>3.0</td>
<td>$0.12 million</td>
</tr>
</tbody>
</table>

Given the present declining demand forecasts, the energy at risk at the 10th percentile level is estimated to reduce from 461 MWh in 2016/17 to 258 MWh by summer 2025/26. Under these conditions there would be insufficient capacity to meet demand for 14 hours in 2025/26. The estimated value to consumers of the energy at risk (258 MWh) in 2025/26 is approximately $10 million. The corresponding expected unserved energy is estimated to be 1.7 MWh, which has a value to consumers of around $0.06 million.

\(^1\) The value of unserved energy is derived from the sector values given in Table 1 in Section 2.4, weighted in accordance with the composition of the load at this terminal station.
If one of the 220/66 kV transformers at MWTS is taken off line during peak loading times and the “N-1” station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is operated by AusNet Transmission Group’s TOC\(^2\) to protect the connection assets from overloading\(^3\), will act swiftly to reduce the load in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with AusNet Electricity Services’ operational procedures after the operation of the OSSCA scheme. If OSSCA operates at MWTS, it would progressively shed up to about 110 MVA of load, affecting approximately 46,000 customers.

**Feasible options for alleviation of constraints**

The following options are technically feasible to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. **Embedded generation:** Bairnsdale Power Station is contracted to provide 20 MW over the night time hot water demand peak and during the afternoon peak demand period but it has the capacity to provide up to 80 MW if needed.

2. **Subject to the availability of the AusNet Transmission Services’ spare 220/66 kV transformer for rural areas** (refer section 5.5), this spare transformer can be used to temporarily replace a failed transformer.

3. **Install a fourth 220/66 kV transformer at MWTS:** Installation of a 4\(^{th}\) transformer at MWTS is a technically feasible option. However, fault level constraints would make such a solution costly to implement.

4. **Installation of Power Factor Correction Capacitors:** As the station is currently running with a power factor of around 0.975 at the summer peak the use of additional capacitors to further improve the power factor and to reduce the MVA loading will provide only marginal benefits.

5. **Load transfers:** Only 5 MVA of load can be shifted away from MWTS using the existing 22 kV distribution network so this option does not make a material contribution to managing the risk at MWTS.

The table on the following page provides more detailed information on the station rating, demand forecasts, energy at risk and expected unserved energy assuming embedded generation is contributing 60 MVA.

\(^2\) Transmission Operation Centre.

\(^3\) OSSCA is designed to protect connection transformers against transformer damage caused by overloads. Damaged transformers can take months to repair or replace, which can result in prolonged, long term risks to the reliability of customer supply.
**MORWELL TERMINAL STATION 66kV (MWTS 66)**

**Detailed data: Magnitude and probability of loss of load**

Distribution Businesses supplied by this station: AusNet Electricity Services (100%)

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<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>406.9</td>
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<td>360.3</td>
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<td>$0.00M</td>
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<td>$0.06M</td>
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<td>N and N-1 Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
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<td>$0.03M</td>
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</table>

Notes:
1. "N-1" means cyclic station output capability rating with outage of one transformer. The summer rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))
MT BEAUTY TERMINAL STATION 66 kV (MBTS 66 kV)

Mt Beauty Terminal Station (MBTS) is the main point of connection into the 220 kV electricity grid for Victoria’s Kiewa hydro generation resources. The power stations include West Kiewa, McKay, Dartmouth, Clover and Eildon. MBTS is also the source of 66 kV supply for the alpine areas of Mt Hotham and Falls Creek along with the townships of Bright, Myrtleford and Mount Beauty.

The station has two 50 MVA 220/66 kV transformers with one transformer in service and the other available as a hot spare that can be brought into service in approximately 4 hours. With this transformer operating arrangement, the N rating will be equal to the “N-1” rating (i.e. equal to the capacity of one transformer). In addition, supply can also be taken from Clover Power Station and the 66 kV tie to Glenrowan Terminal Station via Myrtleford.

It is AusNet Electricity Services’ responsibility to plan the electricity supply network for this region.

Magnitude, probability and impact of loss of load

MBTS is a winter peaking station and winter peak demand on the MBTS 66 kV bus is expected to decline by approximately 1.1% per annum for the next 10 years. Peak demand at the station reached 47.9 MVA in winter 2012. The recorded peak demand in winter 2015 was 43.4 MVA which was lower than the 2012 peak demand due to relatively mild weather conditions experienced in 2015. The station load has a power factor of 0.984 at maximum demand. The demand at MBTS 66 kV is expected to exceed 95% of the 50\textsuperscript{th} percentile peak demand for approximately 4 hours per annum. The summer peak demand is approximately 73% of the winter peak demand.

The graph below depicts the 10\textsuperscript{th} and 50\textsuperscript{th} percentile winter maximum demand forecast together with the station’s operational “N-1” rating (equal to “N” rating) at an ambient temperature of 5°C. With the forecast growth rates, MBTS 66 kV is not expected to reach its “N-1” winter station rating during the 10 year planning horizon.
The above analysis does not include the possibility of loss of load for the short period of about 4 hours that it takes to change over from the in-service transformer to the hot spare transformer. The 66 kV tie line to Glenrowan Terminal Station can support about 25 MW of MBTS load and this tie line is operated normally closed so if the load is below this limit there will not be any loss of customer load during a transformer outage. The Clover power station can generate around 26 MW and so any generation would also minimise the likelihood of the loss of customer load during a transformer outage.

It is recognised that at times of high demand and with low output from Clover power station a transformer outage at MBTS could result in the loss of some customer load for a short period of no more than 4 hours.

The energy at risk for a major transformer outage\footnote{In this report, “major transformer outage” means an outage that has a mean duration of 2.6 months.} in this situation (taking account of the limited 66 kV tie line capability) is significant at around 2,536 MWh in winter 2016 and reducing to 1,007 MWh by 2026 due to forecast negative demand growth. However, given that the hot spare transformer can be made available within 4 hours, the expected outage duration in the case of a major transformer failure at MBTS is 4 hours (rather than 2.6 months). Accordingly, the probability of the transformer being unavailable in this particular case is only 0.000457%. The expected unserved energy at MBTS is therefore approximately 0.005 MWh in 2026 and this is estimated to have a value to consumers of approximately $165 (based on a value of customer reliability of $35,865/MWh).

Full switching of the hot spare transformer with new 220 kV and 66 kV circuit breakers would eliminate this risk but this is estimated to cost around $2 million. The expected benefits of full switching of the hot spare transformer does not economically justify the cost of the project within the ten year planning horizon.
RED CLIFFS TERMINAL STATION (RCTS) 22kV

Red Cliffs Terminal Station (RCTS) 22 kV consists of two 35 MVA 235/66/22 kV transformers supplying the 22 kV network ex-RCTS. An additional 140 MVA 235/66/22 kV transformer operates normally open on the 22 kV bus with an auto-close scheme to close this transformer onto the 22 kV bus in the event of a failure of either of the other two transformers. This configuration is the main source of supply for 6,288 customers in Red Cliffs and the surrounding area. The station supply area includes Red Cliffs, Colignan and Werrimull.

Magnitude, probability and impact of loss of load

The peak load for the RCTS 22 kV network reached 39.8 MW in summer 2016.

It is estimated that:

- For 9 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer power factor at the peak time demand is 0.90.

In the event of a failure of either of the 35 MVA transformers, both 35 MVA transformers will be switched out and the 140 MVA 235/66/22 kV transformer (which operates normally open on the 22 kV bus) will be automatically closed onto the 22 kV bus. There will be a momentary supply interruption during this process. The 140 MVA 235/66/22 kV transformer can also be closed onto the 22 kV bus in the event that load exceeds 55 MVA, with the two 35 MVA transformers being switched out to maintain fault levels below the 13.1 kA limit. This arrangement results in the station’s “N-1” capacity being higher than the “N” capacity.

RCTS 22 kV demand is summer peaking. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating and the “N-1” rating at 35°C ambient temperature.
The graph shows there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service under 50th percentile forecast conditions. Under 10th percentile forecast conditions, there is load at risk from 2023 onwards which can be managed by utilising load transfers to Mildura zone substation. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
RED CLIFFS TERMINAL STATION (RCTS) 66 kV

Red Cliffs Terminal Station (RCTS) 66 kV consists of two 70 MVA and one 140 MVA 235/66/22 kV transformers supplying the 66 kV network ex-RCTS. This configuration is the main source of supply for 21,804 customers in Red Cliffs and the surrounding area. The station supply area includes Merbein, Mildura and Boundary Bend.

Magnitude, probability and impact of loss of load

RCTS 66 kV demand is summer peaking. In February 2012, part of the 66 kV network previously supplied from RCTS was transferred to the new Wemen Terminal Station (WETS). This is reflected in the reduction in actual demand in that year (shown in the chart below). The peak load for the 66 kV network now supplied from the station reached 142.3 MW in summer 2016.

It is estimated that:

- For 9 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand 0.93.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.

The (N) rating on the chart indicates the maximum load that can be supplied from RCTS with all transformers in service. Exceeding this level will initiate automatic load shedding by AusNet Transmission Group’s automatic load shedding scheme.

The above graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand for the duration of the 10 year planning period.
However, if there is a forced transformer outage during peak load periods, from 2023 onwards there will be insufficient capacity to supply the forecast demand at 50th percentile temperature at RCTS66 and some customers might be affected.

**Magnitude, probability and impact of loss of transformer (N-1 System Condition):**

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

![Bar chart](image)

**Comments on Energy at Risk**

For a major outage of one transformer at RCTS 66 kV, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 3.8 hours in summer 2026. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 6.9 MWh in 2026. The estimated value to consumers of the 6.9 MWh of energy at risk is approximately $0.28 million (based on a value of customer reliability of $40,676/MWh).\(^1\)

In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at RCTS 66kV in 2026 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately $0.28 million.

It is emphasised however, that the probability of a major outage of one of the three transformers (two 70 MVA and one 140 MVA) occurring over the year is very low at about 1% per annum, while the expected unavailability per transformer per annum is 0.217% per transformer. When the energy at risk (6.9 MWh for 2026) is weighted by this low probability, the expected

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\(^1\) The value of unserved energy is derived from the sector values given in Table 1 of section 2.4, weighted in accordance with the composition of the load at this terminal station.
unsupplied energy is estimated to be around 0.04 MWh. This expected unserved energy is estimated to have a value to consumers of around $1,800 (based on a value of customer reliability of $40,676/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average summer temperatures occurring in each year. At the 10\textsuperscript{th} percentile temperature and demand level, the energy at risk in 2026 is estimated to be 162 MWh. The estimated value to consumers of this energy at risk in 2026 is approximately $6.59 million. The corresponding value of the expected unserved energy (of 1.05 MWh) is approximately $0.04 million.

These key statistics for the year 2026 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy at risk, at 50th percentile demand forecast under N-1 outage condition</td>
<td>6.9</td>
</tr>
<tr>
<td>Expected unserved energy at 50th percentile demand under N-1 outage condition</td>
<td>0.04</td>
</tr>
<tr>
<td>Energy at risk, at 10\textsuperscript{th} percentile demand forecast under N-1 outage condition</td>
<td>162</td>
</tr>
<tr>
<td>Expected unserved energy at 10\textsuperscript{th} percentile demand under N-1 outage condition</td>
<td>1.05</td>
</tr>
</tbody>
</table>

**Feasible options for alleviation of constraints**

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or alleviate the emerging constraint over the next ten year planning horizon:

1. Contingency transfer away of part of the load (in the order of 13.5 MVA in summer) to WETS and/or to RCTS 22 kV in the event of loss of a transformer at RCTS 66 kV.

2. Powercor is planning to re-conductor part of the WETS-RVL (Wemen Terminal Station to Robinvale) 66 kV line. If this project proceeds, the entire Boundary Bend (BBD) zone substation load (in the order of 35 MVA in summer 2026) can be transferred to WETS in the event of loss of a transformer at RCTS 66 kV.

3. Replace one of the existing 70 MVA transformers with a new 140 MVA unit.

4. Embedded generation. An alternative option to the network solution could be the establishment of an embedded generator, suitably located in the area that is presently supplied by the RCTS 66 kV network.

5. Demand Management. Another alternative option could be the introduction of demand management to reduce the magnitude of the summer peak demands under network emergencies. This might involve the introduction of interruptible load, negotiated with customers at reduced prices, with an agreement that the load can be interrupted during times of network constraint.
Preferred network option(s) for alleviation of constraints

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at RCTS 66 kV, it is proposed to re-conductor part of the WETS-RVL 66 kV line. This project is planned to be completed in 2018 and is justified on the basis of the risk of losing BBD. This project has a secondary benefit of deferring the need to replace one of the existing 70 MVA transformers at RCTS 66 with a new 140 MVA unit. In the summer of 2019 after the project is expected to be complete, all 31 MVA of 2019 BBD load can be transferred to WETS. The project will provide sufficient capacity to transfer all the BBD forecast load in 2026 (in the order of 35 MVA) to WETS.

The capital cost of re-conductoring part of the WETS-RVL line is estimated to be $4.35 million.

Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for rural areas (refer to Section 5.5), a spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
RCTS 66 Terminal Station

<table>
<thead>
<tr>
<th>Distribution Businesses supplied by this station:</th>
<th>Powercor (100%)</th>
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<tbody>
<tr>
<td>MVA</td>
<td></td>
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<tr>
<td>Normal cyclic rating with all plant in service</td>
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<tr>
<td>Summer N-1 Station Rating:</td>
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<tr>
<td>Winter N-1 Station Rating:</td>
<td>192</td>
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<table>
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<tr>
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<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
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<td>151.5</td>
<td>151.9</td>
<td>151.6</td>
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<td>157.5</td>
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<td>90.2</td>
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<td>92.3</td>
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<td>10th percentile Summer Maximum Demand (MVA)</td>
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<td>164.5</td>
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<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
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<td>0.1</td>
<td>0.8</td>
<td>6.9</td>
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<tr>
<td>N-1 hours at risk at 50% percentile demand (hours)</td>
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<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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<td>49.4</td>
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<td>3.8</td>
<td>3.5</td>
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<td>5.0</td>
<td>7.5</td>
<td>14.0</td>
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<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
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<td>0.04</td>
<td>0.04</td>
<td>0.03</td>
<td>0.05</td>
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<td>0.14</td>
<td>0.32</td>
<td>0.55</td>
<td>1.05</td>
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<tr>
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<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
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<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
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<td>$0.00M</td>
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<td>$0.01M</td>
<td>$0.02M</td>
</tr>
<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
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<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.01M</td>
<td>$0.01M</td>
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</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
RICHMOND TERMINAL STATION 22 kV (RTS 22 kV)

RTS 22 kV is a summer critical station equipped with two 165 MVA 220/22 kV transformers, providing supply to 7259 customers in CitiPower’s distribution network. The terminal station’s supply area includes inner suburban areas in Richmond, Prahran and Melbourne City’s Russell Place and surrounding areas. The station also provides supply to City Link and public transport railway substations east of the Central Business District. Due to uneven load sharing between the two 22 kV buses at RTS, the N rating is only slightly higher than the N-1 rating. The N-1 ratings are restricted by over-voltage limits on transformer tapping. A line drop compensator, however, limits the overall 22 kV transformation output to 141 MVA for both summer and winter.

As part of AusNet Transmission Group’s asset renewal program, the two existing 220/22 kV transformers will be replaced by two new 75 MVA 220/22 kV transformers by the end of 2017. The N and N-1 station rating will subsequently change to approximately 190 MVA and 95 MVA respectively. This is reflected in the graph below.

The peak load on the station reached 43.0 MW in summer 2016. It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of peak demand is 0.97.

The graph below depicts the latest 10% and 50% probability maximum demand forecasts during the summer periods over the next ten years, together with the operational N and N-1 ratings for RTS 22 kV. The demand forecasts include the effects of future load transfer works that have been committed. RTS 22 kV load reductions (approximately 25 MVA) in 2014 and 2015 are due to load transfers to RTS 66 kV as part of the Prahran (PR22) Zone Substation decommissioning process. The changes in loads in 2019 to 2024 are due to the Metro Tunnel Project and the transfer of Russell Place Zone Substation (RP22) to RTS 66kV as part of the RP22 decommissioning process.
The graph shows there is sufficient station capacity to supply all anticipated load, and that no customers would be at risk if a forced transformer outage occurred at RTS 22 kV over the forecast period. Accordingly, no capacity augmentation is planned at RTS 22 kV over the next ten years.
RICHMOND TERMINAL STATION 66 kV (RTS 66 kV)

RTS 66 kV is a summer critical station consisting of five 150 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (91%) and United Energy (9%), providing supply to a total of 157,797 customers in the Eastern Central Business District and wide-spread inner suburban areas in the east and south-east of Melbourne, including Fitzroy, Collingwood, Abbotsford, Richmond, North Richmond, Hawthorn, Camberwell, Gardiner, Toorak, Armadale, South Yarra, St Kilda, Elwood and Balaclava.

To limit fault levels, the five transformers at RTS 66 kV are split into two separate groups (1 & 2 bus group, and 3 & 4 bus group).

Following a hot summer period early in 2011, AusNet Transmission Group expressed concern regarding the operating temperature within the RTS 220/66 kV transformers. In order to avoid operating the RTS transformers at temperatures that would result in accelerated aging, and possibly imminent failure, AusNet Transmission Group reviewed the RTS transformer summer cyclic ratings to take account of the latest RTS 66 kV load profile data and information on the transformer cooling effectiveness. These factors necessitated an average reduction of 6% to the transformer cyclic ratings that had applied prior to January 2011 across four of the transformers at an ambient temperature of 35 degrees C. AusNet Transmission Group also advised that its review confirmed that the station rating would be reduced further for ambient temperatures above 35 degrees C.

AusNet Transmission Group has commenced an asset replacement project at RTS to replace the ageing transformers and other plant. AusNet Transmission Group has indicated that it expects the asset replacement project at RTS 66 kV to be completed by the end of 2017 during which time three 225 MVA transformers will replace the five existing 150 MVA transformers.

In December 2011, CitiPower made a connection application for the installation of a temporary 5th 220/66 kV transformer at RTS to reduce the potential for load shedding prior to the completion of the asset replacement work at RTS, or the transfer of load from RTS to the new Brunswick Terminal Station. The temporary 5th transformer (B6) with dual secondary legs has been in service since mid 2013.

With B6 in service, under system normal conditions the No.1, No.4 & No.6 transformers (B1, B4 & B6) are operated in parallel as one group and supply the No.1 & No.2 buses. The No.2 & No.3 transformers (B2 & B3) are operated as a separate group and supply the No.3 & No.4 buses. B6 also supplies the No.3 & No.4 buses with a normally open secondary leg. For an unplanned outage of any one of B2 or B3 transformers, the normally open secondary leg of B6 will close automatically and the normally closed leg of B6 will open automatically. Under this scenario the load demand on the RTS12 group should be kept within the capabilities of the two transformers B1 & B4.

The peak load on the station reached 533.0 MW in summer 2016. It is estimated that:

- For 6 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of peak demand is 0.98.

The following risk assessment is divided into two parts. Part 1 covers 2017, during which the asset replacement project is still in progress. Part 2 covers the period from 2017 to 2026, being the period after the asset replacement project is completed, and there are three 225 MVA transformers in service at RTS.
Part 1: For 2017 - with temporary transformer in service

Magnitude, probability and impact of loss of load for 2017

As noted above, AusNet Transmission Group is undertaking asset replacement works at RTS, which are expected to be completed by the end of 2017. The risk assessment below covers the year 2017, and reflects the impact of the temporary transformer in reducing the loads at risk at RTS.

RTS 1 & 2 66kV Bus Group Summer Peak Forecast for 2017

This bus group supplies CitiPower’s zone substations at Camberwell, Collingwood, North Richmond, Toorak, Armadale and Balaclava and United Energy’s Gardiner zone substation.

The peak load on the RTS 1 & 2 Bus Group reached 320.2 MW in summer 2016.

It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of peak demand is 0.97.

The graph below depicts the RTS 1 & 2 combined 66 kV bus group rating at 35 and 40 degrees under system normal (B1, B4 & B6 in parallel), along with the 50th and 10th percentile summer maximum demand forecasts for the bus group for summer 2017. The actual load for 2016 and the forecast also reflects the transferred load from RTS 22 kV to RTS 66 kV (as Prahran – PR zone substation has been decommissioned).

There is adequate capacity to supply the anticipated maximum load demand on this bus group while all transformers are in service.
Comments on Energy at Risk for RTS 1 & 2 66kV Bus Group for N-1 Condition for 2017

The bar chart below depicts the energy at risk with one transformer out of service (B6 out of service, B1 & B4 in parallel) for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The red cross on the graph shows the value to consumers of the expected unserved energy, for the 50th percentile demand forecast.

For an outage of one transformer supplying 1 & 2 Bus Group at RTS66 kV during the summer period, it is expected that there would be insufficient capacity to supply all demand at the 50th percentile temperature in 2017. This situation would also exist for an outage of a transformer on the 3 & 4 bus group as a transformer on the 1 & 2 group would automatically changeover to the 3 & 4 group.

For 2017, the energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 260.3 MWh. Under these conditions, there would be insufficient capacity to meet demand for approximately 16.8 hours in that year. The estimated value to consumers of this energy at risk in 2017 is approximately $10.5 million (based on a value of customer reliability of $40,292 per MWh). In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at RTS 66 kV over the summer of 2017 would be anticipated to lead to involuntary supply interruptions that would cost consumers $10.5 million.

It is emphasised however, that the probability of a major outage of one of the five transformers at RTS 66 kV occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When

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1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
the energy at risk in 2017 (260.3 MWh) is weighted by the low transformer unavailability, the expected unserved energy is estimated to be around 1.7 MWh. This expected unserved energy is estimated to have a value to consumers of approximately $0.07 million in 2017.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile summer temperature conditions, the energy at risk in 2017 is estimated to be 2,252 MWh. The estimated value to consumers of this energy at risk in 2017 is approximately $90.7 million. The corresponding value of the expected unserved energy (of 14.6 MWh) is approximately $0.59 million.

These key statistics for the year 2017 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy at risk, at 50th percentile demand forecast</td>
<td>260.3</td>
</tr>
<tr>
<td>Expected unserved energy at 50th percentile demand</td>
<td>1.7</td>
</tr>
<tr>
<td>Energy at risk, at 10th percentile demand forecast</td>
<td>2,252</td>
</tr>
<tr>
<td>Expected unserved energy at 10th percentile demand</td>
<td>14.6</td>
</tr>
</tbody>
</table>

If one of the transformers at RTS 66 kV is taken off line during peak loading times and the N-1 station rating is exceeded, then the OSSCA2 load shedding scheme which is operated by AusNet Transmission Group TOC3 will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored where transfer capacity exists after the operation of the OSSCA scheme, at zone substation feeder level in accordance with CitiPower and United Energy’s operational procedures.

**RTS 3 & 4 66kV Bus Group Summer Peak Forecast for 2017**

This bus group supplies CitiPower’s zone substations in the Melbourne CBD and St Kilda and United Energy’s Elwood zone substation.

The peak load on the RTS 3 & 4 Bus Group reached 215.2 MW in summer 2016.

It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of peak demand is 0.99.

The graph below depicts the RTS 3 & 4 combined 66 kV bus group rating at 35 and 40 degrees under system normal (B2 & B3 in parallel), along with the 50th and 10th percentile summer maximum demand forecasts for summer 2017. With the installation of the

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2 Overload Shedding Scheme of Connection Asset.
3 Transmission Operation Centre.
temporary 5th transformer, there is adequate capacity to supply the anticipated maximum load demand on this bus group while all transformers are in service.

**Comments on Energy at Risk for RTS 3 & 4 66kV Bus Group for N-1 Condition for 2017**

For an outage of one transformer supplying 3 & 4 Bus Group at RTS 66 kV during the summer period, it is expected that there would be sufficient capacity to supply all the demand at the 50th percentile and the 10th temperatures on the RTS buses 3 and 4 combined 66 kV bus group until 2017.

**Part 2: Period between 2018 to 2026 - three 225 MVA transformers in service**

**Magnitude, probability and impact of loss of load from 2018 to 2026**

The risk assessment below addresses the period from 2018 to 2026, following the completion of the station asset replacement project. From 2018:

- there will be three 225 MVA transformers in service at RTS; and
- the 66 kV bus arrangement will be closed and all transformers will operate in parallel mode.

For this report, it is assumed that the station output ratings are 552 MVA for summer and 594 MVA for winter, based on typical data from existing similar stations. The ratings will be confirmed pending receipt of actual transformer test report information from the manufacturers.

The graph below depicts the total station N and N-1 rating at 35 degrees and the latest 10th and 50th percentile maximum demand forecast for the period from 2018 to 2026. The load forecast reflects the committed projects to transfer load from RTS 22 kV to RTS 66 kV (Prahran – PR zone substation decommissioning) and RTS 66 kV to the new BTS 66 kV terminal station by 2019/20.
The graph shows that with all three transformers in service there will be sufficient capacity at RTS 66kV to supply the forecast 10th percentile and 50th percentile demands for the forecast period. However, with one transformer out of service there will be insufficient capacity to supply all demand in 2018 and 2019.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating for 2018 and 2019. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.
For a major outage of one transformer at RTS66 kV during the summer period, it is expected that there would be insufficient capacity to supply all demand at the 50th percentile temperature for 2018 and 2019.

For 2018, the energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 57.9 MWh. Under these conditions, there would be insufficient capacity to meet demand for approximately 4.5 hours in that year. The estimated value to consumers of this energy at risk in 2018 is approximately $2.4 million (based on a value of customer reliability of $41,416 per MWh). In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at RTS 66 kV over the summer of 2018 would be anticipated to lead to involuntary supply interruptions that would cost consumers $2.4 million.

It is emphasised however, that the probability of a major outage of one of the five transformers at RTS 66 kV occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk in 2017 (57.9 MWh) is weighted by the low transformer unavailability, the expected unserved energy is estimated to be around 0.4 MWh. This expected unserved energy is estimated to have a value to consumers of approximately $0.02 million in 2018.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) summer temperatures occurring in each year. Under 10th percentile summer temperature conditions, the energy at risk in 2018 is estimated to be 994.5 MWh. The estimated value to consumers of this energy at risk in 2018 is approximately $41.2 million. The corresponding value of the expected unserved energy (of 6.5 MWh) is approximately $0.27 million.

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4 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.

5 As noted in Section 4.1, the 50th percentile demand forecast is used in each year.
These key statistics for the year 2018 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy at risk, at 50th percentile demand forecast</td>
<td>57.9</td>
</tr>
<tr>
<td>Expected unserved energy at 50th percentile demand</td>
<td>0.4</td>
</tr>
<tr>
<td>Energy at risk, at 10th percentile demand forecast</td>
<td>994.5</td>
</tr>
<tr>
<td>Expected unserved energy at 10th percentile demand</td>
<td>6.5</td>
</tr>
</tbody>
</table>

If one of the transformers at RTS 66 kV is taken off line during peak loading times and the N-1 station rating is exceeded, then the OSSCA\(^6\) load shedding scheme which is operated by AusNet Transmission Group TOC\(^7\) will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored where transfer capacity exists after the operation of the OSSCA scheme, at zone substation feeder level in accordance with CitiPower and United Energy’s operational procedures.

**Feasible options for alleviation of constraints**

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate emerging constraints:

1. Permanent load transfer from RTS 66 kV to the proposed BTS 66 kV (Brunswick Terminal Station) connection point. This is part of the integrated plan for the proposed BTS 66 kV (Refer to the Risk Assessment Report for BTS 66 kV) and will be achieved as follows:

   - CitiPower has committed to a bulk subtransmission transfer of normal supply of MP zone substation (approximately 135 MVA) in the CBD from RTS 66 kV to the new BTS 66 kV station by summer 2019/20.
   - High voltage distribution load transfer from critical zone substations in the Central Business District areas supplied from RTS 66 kV to the upgraded zone substations supplied from the proposed BTS 66 kV commencing from 2020.
   - Bulk subtransmission transfer of normal supply of future WP zone substation load (approximately 30 MVA) in the CBD from RTS 66 kV to the new BTS 66 kV by 2020. 66 kV switching will be available at WP zone substation, and this transfer may be a contingency response.

2. Bulk subtransmission transfer of normal supply of a three-zone substation 66 kV subtransmission loop (about 135 MVA of load) from RTS 66 kV to the new BTS 66 kV.

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\(^6\) Overload Shedding Scheme of Connection Asset.

\(^7\) Transmission Operation Centre.
3. A feasible option to provide added security to the CBD would involve CitiPower and United Energy working closely with AusNet Transmission Group to install an additional 220/66 kV 225 MVA transformer at RTS in conjunction with AusNet Transmission Group’s RTS asset replacement program.

4. Demand Reduction: United Energy has developed a number of innovative network tariffs to encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and will be taken into consideration when determining the optimum timing for the capacity augmentation.

5. Embedded generation in the order of 150 MVA, would help to defer the need for augmentation.

**Preferred option(s) for alleviation of constraints**

It is proposed to reduce load from RTS 66 kV permanently by transferring load away to the new BTS 66 kV. This transfer will be done via subtransmission networks by 2020, which is in line with the integrated plan for the establishment of the new BTS 66 kV supply point.

Prior to the establishment of BTS, the following actions will be taken to mitigate supply interruption risk at RTS 66 kV under critical loading conditions:

- Contingency plans will be put in place for summer peak loading periods in 2017, 2018 and 2019 to:
  - transfer bulk load at 66 kV from RTS 1 & 2 66 kV bus group to MTS during emergency conditions. The plans may also include 11 kV distribution network transfers and load management; and
  - transfer bulk load at 66 kV from RTS 1 & 2 66 kV bus group to BTS 66 utilising temporary 66 kV ties and protection already in place within CitiPower zone substations.
- Subject to availability, installation of an AusNet Transmission Group’s spare 220/66 kV transformer for metropolitan areas could be undertaken to temporarily replace a failed transformer at RTS 66 kV.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
### RICHMOND TERMINAL STATION 1 & 2 66 kV Bus Group

**Detailed data: Magnitude and probability of loss of load**

<table>
<thead>
<tr>
<th>Distribution Businesses supplied by this bus group:</th>
<th>CitiPower (91%), United Energy (9%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bus group summer operational rating (N elements in service):</strong></td>
<td>481 MVA via 3 transformers in parallel</td>
</tr>
<tr>
<td><strong>Bus group winter operational rating (N elements in service):</strong></td>
<td>547 MVA via 3 transformers in parallel</td>
</tr>
<tr>
<td><strong>Summer N-1 bus group rating</strong></td>
<td>319 MVA via 2 transformers in parallel</td>
</tr>
<tr>
<td><strong>Winter N-1 bus group rating</strong></td>
<td>353 MVA via 2 transformers in parallel</td>
</tr>
</tbody>
</table>

#### Station: RTS 1 & 2 66kV Bus Group

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>357.2</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>284.1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>405.5</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
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<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Annual N-1 energy at risk at 50th percentile demand (MWh)</td>
<td>260.3</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>Annual N-1 energy at risk at 50th percentile demand (hours)</td>
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<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<td>N/A</td>
<td>N/A</td>
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<tr>
<td>Annual N-1 energy at risk at 10th percentile demand (MWh)</td>
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<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>Annual N-1 energy at risk at 10th percentile demand (hours)</td>
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<td>N/A</td>
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<td>N/A</td>
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<td>N/A</td>
<td>N/A</td>
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<td>N/A</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy at 50th percentile demand (MWh)</td>
<td>1.7</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy at 10th percentile demand (MWh)</td>
<td>14.6</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy value at 50th percentile demand</td>
<td>$0.07M</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy value at 10th percentile demand</td>
<td>$0.59M</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
<td>$0.22M</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

#### Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published on June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)).
7. The N and N-1 ratings are approximately equal due to the restriction of “Normal Open Auto-close” transformer duty. The N rating will be increased to about 700MVA when the restriction is removed.
RICHMOND TERMINAL STATION 66 kV Total (post rebuild)

Detailed data: Magnitude and probability of loss of load

<table>
<thead>
<tr>
<th>Distribution Businesses supplied by this Terminal Station</th>
<th>CitiPower (91%), United Energy (9%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RTS Summer operational rating (N elements in service):</td>
<td>820 MVA via 3 transformers in parallel</td>
</tr>
<tr>
<td>RTS Winter operational rating (N elements in service):</td>
<td>820 MVA via 3 transformers in parallel</td>
</tr>
<tr>
<td>RTS Summer N-1 Operational rating</td>
<td>552 MVA via 2 transformers in parallel</td>
</tr>
<tr>
<td>RTS Winter N-1 Operational rating:</td>
<td>552 MVA via 2 transformers in parallel</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Station: RTS Terminal Station</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>N/A</td>
<td>574.9</td>
<td>569.8</td>
<td>455.9</td>
<td>457.3</td>
<td>447.0</td>
<td>445.6</td>
<td>444.0</td>
<td>436.3</td>
<td>433.0</td>
</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>N/A</td>
<td>465.9</td>
<td>469.2</td>
<td>384.5</td>
<td>388.3</td>
<td>392.7</td>
<td>397.9</td>
<td>401.7</td>
<td>405.1</td>
<td>408.6</td>
</tr>
<tr>
<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>N/A</td>
<td>634.4</td>
<td>629.7</td>
<td>516.7</td>
<td>515.5</td>
<td>508.9</td>
<td>504.4</td>
<td>501.9</td>
<td>496.8</td>
<td>494.4</td>
</tr>
<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
<td>N/A</td>
<td>498.1</td>
<td>502.4</td>
<td>418.6</td>
<td>422.7</td>
<td>427.7</td>
<td>433.8</td>
<td>438.0</td>
<td>441.5</td>
<td>445.1</td>
</tr>
<tr>
<td>Annual N - 1 energy at risk at 50th percentile demand (MWh)</td>
<td>N/A</td>
<td>57.9</td>
<td>36.6</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Annual N - 1 energy at risk at 50th percentile demand (hours)</td>
<td>N/A</td>
<td>4.5</td>
<td>3.8</td>
<td>0.0</td>
<td>0.0</td>
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<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Annual N - 1 energy at risk at 10th percentile demand (MWh)</td>
<td>N/A</td>
<td>994.5</td>
<td>854.7</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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</tr>
<tr>
<td>Annual N - 1 energy at risk at 10th percentile demand (hours)</td>
<td>N/A</td>
<td>31.3</td>
<td>28.8</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy at 50th percentile demand (MWh)</td>
<td>N/A</td>
<td>0.4</td>
<td>0.2</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy at 10th percentile demand (MWh)</td>
<td>N/A</td>
<td>6.5</td>
<td>5.6</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy at 50th percentile demand</td>
<td>N/A</td>
<td>$0.02M</td>
<td>$0.01M</td>
<td>$0.0M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy at 10th percentile demand</td>
<td>N/A</td>
<td>$0.27M</td>
<td>$0.23M</td>
<td>$0.0M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
</tr>
<tr>
<td>Expected Annual Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
<td>N/A</td>
<td>$0.09M</td>
<td>$0.08M</td>
<td>$0.0M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
<td>$0.00M</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 4.3.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published on June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx).
7. The N and N-1 ratings are approximately equal due to the restriction of “Normal Open Auto-close” transformer duty. The N rating will be increased to about 700MVA when the restriction is removed.
RINGWOOD TERMINAL STATION 22 kV (RWTS 22 kV)

Ringwood Terminal Station provides supply at two voltage levels - 66 kV and 22 kV. RWTS 22 kV is now supplied by two 75 MVA 220/22 kV three-phase transformers following completion of AusNet Transmission Group’s asset replacement project in 2013. RWTS 22 kV is the main source of 22 kV supply for the local area and for the commuter railway network.

The geographic coverage of the station’s supply area includes Ringwood, Mitcham, Wantirna and Nunawading. The electricity distribution networks for this area are the responsibility of both AusNet Electricity Services (68%) and United Energy Distribution (32%).

Magnitude, probability and impact of loss of load

Peak demand at the station occurs in summer. Growth in summer peak demand at RWTS 22 kV is forecast to decline by approximately 0.1% per annum over the ten year planning horizon. The station recorded a peak demand of 90.2 MW (92 MVA) in summer 2015/16 which is the highest recorded peak demand since the summer 2009 peak demand of 96.2 MVA. The peak demand in summer 2015/16 was 21 MW (28%) higher than the 2014/15 peak demand. Demand at RWTS 22 kV is expected to exceed 95% of the 50th percentile peak demand for 3 hours per annum. The station load has a power factor of 0.98 at maximum demand but load on the transformers has a power factor of 1 if all the 22 kV capacitors are switched in at the station.

RWTS 22 kV is not expected to be loaded above its “N-1” rating under 10th and 50 percentile summer maximum demand forecasts during the ten year planning horizon. The graph below depicts the 10th and 50 percentile summer maximum demand forecasts together with the station’s “N-1” rating at an ambient temperature of 35°C.

As already noted, demand remains below the “N-1” rating under both 10th percentile and 50th percentile maximum demand forecasts for the ten year planning period between 2016/17 to 2025/26. There is therefore not expected to be any need for augmentation or other corrective action over the ten year planning period.
RINGWOOD TERMINAL STATION 66 kV (RWTS 66 kV)

Ringwood Terminal Station is the main source of supply for a major part of the outer eastern metropolitan area. The geographic coverage of the station’s supply area spans from Lilydale and Woori Yallock in the north east; to Croydon, Bayswater and Boronia in the east; and Box Hill, Nunawading and Ringwood to the west.

The electricity supply distribution networks for this region are the responsibility of both AusNet Electricity Services (82%) and United Energy (18%).

Background

Ringwood Terminal Station provides supply at two voltage levels - 66 kV and 22 kV. RWTS 66 kV is supplied by four 150 MVA 220/66 kV transformers and peak demand occurs in summer.

In March 2016 the B2 transformer at RWTS failed. It was replaced in August 2016 by one of the metropolitan spare transformers. AusNet Transmission Group plans to replace the No. 4 220/66 kV transformer with a new 150 MVA unit in 2018.

The existing four transformers are operated in two separate bus groups to limit the maximum fault currents on the 66 kV buses within their respective switchgear ratings. Under network normal configuration, the No. 1 and No. 2 transformers are operated in parallel as one group (RWTS bus group 1-3) and supply the No.1 and No. 3 66 kV buses respectively. The No. 3 and No. 4 transformers are operated in parallel as another group (RWTS bus group 2-4) and supply the No.2 and No. 4 66 kV buses respectively. To configure the station as two separate bus groups, the 66 kV bus 1-2 and bus 3-4 tie circuit breakers are operated normally open.

Given this configuration, load demand on the RWTS bus groups 1-3 and 2-4 must be kept within the capabilities of their respective two transformers at all times otherwise load shedding may occur. For an unplanned transformer outage in any of the two RWTS bus groups, an auto close scheme will operate resulting in parallel operation of the three remaining transformers.

Combined Summer Peak Demand forecasts for RWTS 66 kV - Total Station Demand

The peak demand on the station reached 494 MW (495 MVA) in summer 2013/14. The recorded peak demand in summer 2015/16 was 466.5 MW (476.7 MVA), which was lower than the summer 2013/14 station peak demand. The station load has a power factor of 0.979 at maximum demand but the load on the transformers has a power factor of 1 due to installed 66 kV capacitor banks. RWTS 66 kV demand is expected to exceed 95% of the 50th percentile peak demand for 7 hours per annum. Forecast demand growth has significantly declined due to weaker economic conditions, appliance energy efficiency, rooftop solar generation and the impact of increases in the cost of electricity.

RWTS 66 kV is not expected to be loaded above its “N-1” rating under 50th or 10th percentile summer maximum demand forecasts during the ten year planning period, except for the first four years when the 10th percentile summer maximum demand forecast slightly exceeds the station N-1 rating at an ambient temperature of 40°C. The graph below depicts the 10th and 50th percentile summer maximum demand forecasts together with the station’s “N” and “N-1” ratings at ambient temperatures of 35°C and 40°C.
The combined winter demand at RWTS 66 kV is not expected to reach the station’s “N–1” winter rating during the ten year planning horizon.

**Total Station Load: RWTS 66 kV Summer Peak Demand Forecasts**

**RWTS Bus groups 1-3 and 2-4: Summer Peak Demand Forecasts**

In addition to considering the station’s total summer demand under “N-1” conditions as shown above, it is essential to assess the risk of load shedding on the individual bus groups when both of their respective transformers are in service, i.e under “N” conditions.

**RWTS Bus group 1-3:** Peak demand at RWTS 66 kV bus group 1-3 occurs in summer. Based on the individual summer demand forecasts for this bus group, with both transformers in service, i.e. under “N” conditions, the demand on this bus group at the 50th and 10th percentile temperatures is forecast to remain within its “N” rating throughout the ten year planning horizon, except for the last year of the planning period when the 10th percentile summer maximum demand forecast slightly exceeds the “N” rating at an ambient temperature of 40°C. There is no expectation of load shedding being required to keep loading within plant ratings on this bus group under normal operating conditions during summer.

This bus group supplies United Energy’s zone substations Nunawading (NW) and Box Hill (BH), and AusNet Electricity Services’ zone substations Ringwood North (RWN), Lilydale (LDL), Chirnside Park (CPK) and Woori Yallock (WYK).

The graph below depicts the 10th and 50th percentile summer maximum demand forecasts together with the bus group 1-3 “N” rating at an ambient temperature of 35°C and 40°C.
RWTS Bus group 2-4: Similar to bus group 1-3, the peak demand at RWTS 66 kV bus group 2-4 also occurs in summer. Based on the individual summer demand forecasts for this bus group, with both transformers in service, i.e. under “N” conditions, the demand on this bus group at the 50th or 10th percentile temperature is forecast to remain within its “N” rating throughout the ten year planning horizon. This means that there is no expectation of load shedding being required to keep loading within plant ratings on this bus group under normal operating conditions during summer.

This bus group supplies AusNet Electricity Services’ zone substations Boronia (BRA), Croydon (CYN) and Bayswater (BWR).

The graph below depicts the 10th and 50th percentile summer maximum demand forecasts together with the bus group 2-4 rating at an ambient temperature of 35°C and 40°C.
The above two graphs show that with all plant in service, there is no energy at risk on either of the individual bus groups under 50th percentile or 10th percentile loading conditions for the summer period over the ten year planning period.

As already noted, for the first four years (2016/17 and 2019/20) of the planning period, the 10th percentile summer maximum demand forecast slightly exceeds the station N-1 rating at an ambient temperature of 40°C. Specifically, in 2016/17 approximately 26 MVA is at risk, while in 2019/20 approximately 1 MVA is a risk. To manage this load at risk, AusNet Electricity Services and United Energy have plans to enable load transfers under contingency conditions via emergency 66 kV ties to the adjacent East Rowville and Templestowe terminal stations, respectively. The emergency 66 kV ties from RWTS 66 kV can be in operation within a few hours and have a transfer capability of approximately 50 MVA each.

After 2019/20, there is expected to be sufficient capacity at the station to supply all demand at the 50th percentile or 10th percentile temperatures under N-1 conditions. On this basis, there is not expected to be any need for augmentation over the ten year planning period.
SHEPPARTON TERMINAL STATION (SHTS) 66 kV

Shepparton Terminal Station (SHTS) 66 kV consists of three 150 MVA 220/66 kV transformers and is the main source of supply for over 70,702 customers in Shepparton and the Goulburn–Murray area. The station supply area includes the towns of Shepparton, Echuca, Mooroopna, Yarrawonga, Kyabram, Cobram, Numurkah, Tatura, Rochester, Nathalia, Tongala, and Rushworth.

Magnitude, probability and impact of loss of load

Demand at SHTS is summer peaking. Growth in summer peak demand at SHTS has averaged around 0.3 MVA (0.2%) per annum over the last 5 years. Peak load on the station in the summer of 2016 reached 282.1 MW.

It is estimated that:

- For 6 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.97.

The chart below depicts the 10th and 50th percentile summer maximum demand forecast together with the station operational “N” rating (all transformers in service) and the “N−1” rating at 35°C ambient temperature.

The chart shows there is sufficient capacity at the station to supply all expected demand at the 50th and 10th percentile temperature, over the forecast period even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
SOUTH MORANG TERMINAL STATION (SMTS 66 kV)

Background

A 220/66 kV connection station with two 220/66 kV 225 MVA transformers was established at the existing South Morang Terminal Station (SMTS) site in 2008. The re-arrangement of 66 kV loops with the establishment of SMTS resulted in the 140 MVA Somerton Power Station being connected to the SMTS 66 kV bus.

The geographic coverage of the area supplied by the new connection assets at SMTS spans from Seymour, Kilmore, Kalkallo, Kinglake and Rubicon in the north to Mill Park in the south and from Doreen and Mernda in the east to Somerton and Craigieburn in the west. The electricity distribution networks for this area are the responsibility of both AusNet Electricity Services (70%) and Jemena Electricity Networks (30%).

SMTS is a summer peaking station which recorded a maximum demand of 284.7 MW (291.6 MVA) in summer 2013/14. The recorded peak demand in summer 2015/16 was 287.6 MW (289.8 MVA) which was marginally lower than the 2013/14 station peak demand (measured in terms of MVA). The station load has a power factor of 0.992 at maximum demand. Demand is expected to exceed 95% of the 50th percentile peak demand for 4 hours per annum. The summer and winter demand at SMTS 66 kV are forecast to increase at 3% and 4% per annum respectively over the planning horizon.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C as well as 40°C ambient temperatures.

The “N” rating on the above chart indicates the maximum load that can be supplied from SMTS with both transformers in service.
With the projected growth in customer demand in the area, it is expected that SMTS will exceed its “N-1” rating in summer at the 50th percentile and 10th percentile summer demand forecasts, as shown in the graph above.

In the winter, the rating of the transformers is higher than the summer rating due to lower ambient temperatures. Thus, energy at risk during the winter period is generally lower than the summer period. The graph below demonstrates the 10th and the 50th percentile winter maximum demand forecast together with the station’s operational “N" rating and “N-1” rating. SMTS is expected to be loaded above its “N-1” rating under both 50th percentile and 10th percentile winter maximum demand forecasts from 2020.

The bar chart below depicts the energy at risk over the winter and summer periods with one transformer out of service for the 50th percentile demand forecast, and the hours each year that the 50th percentile demand forecast is expected to exceed the “N-1” station capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.
As already noted, SMTS 66 kV is a summer peaking station and most of the energy at risk occurs in the summer period because the rating of the transformers is lower at higher ambient temperatures in addition to higher summer demand. The comments below therefore focus on the energy at risk over the summer period.

**Comments on Energy at Risk assuming Somerton Power Station is unavailable**

Assuming that Somerton Power Station is unavailable, then for an outage of one transformer at SMTS over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 285 hours in summer 2025/26. The energy at risk at the 50th percentile temperature under “N-1” conditions is estimated to be 11,588 MWh in summer 2025/26. The estimated value to consumers of the 11,588 MWh of energy at risk is approximately $424 million (based on a value of customer reliability of $36,611/MWh)\(^1\). In other words, at the 50th percentile demand level, without any contribution from embedded generation and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at SMTS in summer 2025/26 would be anticipated to lead to involuntary supply interruptions that would cost consumers $424 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (11,588 MWh) is weighted by this low transformer unavailability, the expected unserved energy is estimated to be around 50.2 MWh. This expected unserved energy is estimated to have a value to consumers of around $1.84 million (based on a value of customer reliability of $36,611/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) temperatures occurring each

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\(^1\) The value of unserved energy is derived from the sector values given in Table 1 in Section 2.4, weighted in accordance with the composition of the load at this terminal station.
year. Under higher temperature conditions (that is, at the 10th percentile level), the energy at risk in 2025/26 summer is estimated to be 25,020 MWh. The estimated value to consumers of the energy at risk in 2025/26 summer is approximately $916 million. The corresponding value of the expected unserved energy (of 108.4 MWh) is approximately $3.97 million.

These key statistics for the summer of 2025/26 under “N-1” outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
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<tbody>
<tr>
<td>Energy at risk, at 50th percentile demand forecast</td>
<td>11,588</td>
</tr>
<tr>
<td>Expected unserved energy at 50th percentile demand</td>
<td>50.2</td>
</tr>
<tr>
<td>Energy at risk, at 10th percentile demand forecast</td>
<td>25,020</td>
</tr>
<tr>
<td>Expected unserved energy at 10th percentile demand</td>
<td>108.4</td>
</tr>
</tbody>
</table>

If one of the 220/66 kV transformers at SMTS is taken off line during peak loading times and the “N-1” station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA), which is operated by AusNet Transmission Group’s TOC 2 to protect the connection assets from overloading, will act swiftly to reduce the loads in blocks to within safe loading limits. In the event of OSSCA operating, it would automatically shed up to 40 MVA of load, affecting approximately 15,000 customers in 2016/17. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at feeder level in accordance with AusNet Electricity Services and Jemena’s operational procedures after the operation of the OSSCA scheme.

Comments on Energy at Risk assuming Somerton Power Station is available

The previous comments on energy at risk are based on the assumption that there is no embedded generation available to offset the 220/66 kV transformer loading. The Somerton Power Station (SPS) is capable of generating up to 140 MVA and this generation is connected to the SMTS 66 kV bus via the SMTS-ST-SSS-SMTS 66 kV loop. There is no firm commitment that generation will be available to offset transformer loading at SMTS; however it is most likely that the times of peak demand at SMTS will coincide with periods of high wholesale electricity prices, resulting in a high likelihood that SPS will be generating. If SPS is generating to its full capacity there would be no energy at risk at SMTS over the ten year planning horizon for the 50th percentile summer maximum demand forecast except for a small amount of energy at risk in 2025/26. However for the 10th percentile summer maximum demand forecast, there would be a significant amount of energy at risk during the summer period from the year 2021/22 onwards.

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of a supply interruption and/or to alleviate the emerging capacity constraints:

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2 Transmission Operation Centre.

3 OSSCA is designed to protect connection transformers against transformer damage caused by overloads. Damaged transformers can take months to repair or replace which can result in prolonged, long term risks to the reliability of customer supply.
1. Implement contingency plans to transfer load to adjacent terminal stations. AusNet Electricity Services has established and implemented the necessary plans that enable up to 20 MVA of load transfers via existing 22 kV feeders to adjoining zone substations. Jemena has plans and the capability to transfer an additional 11 MVA. This option is able to partly reduce the interruption duration and load at risk resulting from a major transformer failure.

2. Install a third 225 MVA 220/66 kV transformer at South Morang Terminal Station (SMTS), which would also require the installation of fault limiting reactors.

3. Demand Management. AusNet Electricity Services is currently using an MVA tariff to encourage large customers to improve their power factor as well as a critical peak pricing tariff to encourage them to reduce load at peak demand times and thus reduce the station loading. Up to 50% of the maximum demand at SMTS 66 kV is expected to be summer residential load, largely air conditioning. With the existing load mix it is likely that demand reduction initiatives can play a limited role in reducing the peak summer load at SMTS 66 kV.

4. Embedded Generation. As mentioned above, the Somerton power station is connected to SMTS. A network support agreement with SPS or other generator connected to the SMTS 66 kV bus will help to defer the need for augmentation.

**Preferred network option for alleviation of constraints**

1. In the event that there are no firm commitments by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce future load at SMTS 66 kV; it will be proposed to install a new third 220/66 kV transformer at SMTS 66 kV. The capital cost of this option is estimated at $22 million, which includes the cost of installing three fault limiting reactors. This equates to a total annual cost of approximately $2.2 million per annum. Under the latest demand forecast, the installation of the third transformer at SMTS could be economically justified in 2024/25. The installation of a third transformer would be economic in 2022/23 based on AEMO’s previous VCR estimate (escalated to 2016 dollars).

2. Implement the following temporary measures to cater for an unplanned outage of one transformer at SMTS under critical loading conditions until the new 220/66 kV transformer is commissioned:
   - maintain contingency plans to transfer load quickly to adjacent terminal stations;
   - rely on Somerton Power Station (SPS) generation to reduce loading at SMTS 66 kV, and investigate the option of formalising a network support agreement with SPS;
   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading; and
   - subject to the availability of AusNet Transmission Group’s spare 220/66 kV transformer for the metropolitan area (refer Section 5.5), this spare transformer can be used to temporarily replace a failed transformer at SMTS. It is noted that AusNet Transmission Group currently has one 150 MVA spare transformer, with a second spare to be procured by late 2017. Load sharing with a metro spare transformer will not be optimal, so the SMTS 66 kV capacity will be reduced under these emergency conditions.
The table on the following page provides more detailed data on the station rating, demand forecast, energy at risk and expected unserved energy assuming embedded generation is not available.
SOUTH MORANG TERMINAL STATION 66kV Loading (SMTS 66 kV)

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: AusNet Electricity Services (70%) Jemina Electricity Networks (30%)

Normal cyclic rating with all plant in service 530 MVA via 2 transformers (Summer peaking)

Summer N-1 Station Rating 265 MVA [See Note 1 below for interpretation of N-1]

Winter N-1 Station Rating 294 MVA

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</tr>
</thead>
<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>302.2</td>
<td>314.0</td>
<td>327.5</td>
<td>338.8</td>
<td>354.3</td>
<td>363.2</td>
<td>378.4</td>
<td>391.5</td>
<td>401.0</td>
<td>411.8</td>
</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>261.1</td>
<td>271.2</td>
<td>282.5</td>
<td>294.0</td>
<td>303.1</td>
<td>313.8</td>
<td>325.6</td>
<td>334.6</td>
<td>344.2</td>
<td>353.9</td>
</tr>
<tr>
<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>341.9</td>
<td>353.8</td>
<td>368.1</td>
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<td>397.4</td>
<td>410.2</td>
<td>424.4</td>
<td>438.2</td>
<td>450.9</td>
<td>463.1</td>
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<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
<td>265.6</td>
<td>276.2</td>
<td>288.1</td>
<td>300.1</td>
<td>309.6</td>
<td>320.8</td>
<td>333.0</td>
<td>342.4</td>
<td>352.1</td>
<td>362.0</td>
</tr>
</tbody>
</table>

N - 1 energy at risk at 50th percentile demand (MWh) 246 486 977 1,605 2,861 3,853 6,062 8,579 11,209 14,919

N - 1 hours at risk at 50th percentile demand (hours) 18 29 53 76 119 153 217 304 382 523

N - 1 energy at risk at 10th percentile demand (MWh) 1,978 2,762 4,001 5,543 7,893 10,466 14,169 18,628 23,847 30,407

N - 1 hours at risk at 10th percentile demand (hours) 68 88 123 164 231 304 414 521 692 885

Expected Unserved Energy at 50th percentile demand (MWh) 1 2 4 7 12 17 26 37 49 65

Expected Unserved Energy at 10th percentile demand (MWh) 9 12 17 24 34 45 61 81 103 132

Expected Unserved Energy value at 50th percentile demand $0.04M $0.08M $0.16M $0.25M $0.45M $0.61M $0.96M $1.36M $1.78M $2.37M

Expected Unserved Energy value at 10th percentile demand $0.31M $0.44M $0.63M $0.88M $1.25M $1.66M $2.25M $2.96M $3.78M $4.82M

Expected Unserved Energy using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value $0.12M $0.19M $0.30M $0.44M $0.69M $0.93M $1.35M $1.84M $2.38M $3.10M

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The summer rating is at an ambient temperature of 35 degrees Centigrade.

2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.

3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.

4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.

5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.

6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
SPRINGVALE TERMINAL STATION (SVTS)

Springvale Terminal Station (SVTS) is located in the south east of greater Melbourne. The geographic coverage of the station's supply area spans from Blackburn in the north to Noble Park in the south and from Wantirna South in the east to Riversdale in the west. The electricity supply network for this large region is split between United Energy (UE) and CitiPower (CP).

Background

SVTS was augmented with a new 150 MVA 220/66 kV transformer in 2006 to reinforce the security and reliability of supply for customers in the area. The station now has four 150 MVA 220/66 kV transformers and operates in a split bus arrangement. Under system normal conditions the No.1 & No.2 transformers (B1 & B2) are operated in parallel as one group (SVTS1266) and supply the No.1 & No.2 buses. The No.3 & No.4 transformers (B3 & B4) are operated in parallel as a separate group (SVTS3466) and supply the No.3 & No.4 buses. Connection between No.1 & No.4 buses is maintained via transfer buses No.5 & No.6. The 66 kV bus 2-3 and bus 4-5 tie circuit breakers are operated normally open to limit the fault levels on the 66 kV buses to within switchgear ratings. For an unplanned outage of any one of the four transformers, 66 kV bus 2-3 and bus 4-5 tie circuit breakers will close automatically and maintain the station in a 3-transformer closed loop arrangement. Given this configuration, the demand on the station will therefore need to be controlled as follows:

- Load demand on the SVTS1266 group should be kept within the capabilities of the two transformers B1 & B2 at all times.
- Load demand on the SVTS3466 group should be kept within the capabilities of the two transformers B3 & B4 at all times.
- Load demand on the total station should be kept within the capabilities of any three transformers when one transformer is out of service.

SVTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 478 MW (491 MVA) in summer 2009 under extreme weather conditions. The peak demand in summer 2016 was 422.8 MW (428.2 MVA). Six embedded generation units over 1 MW are connected at SVTS 66 kV.¹

The magnitude, probability and load at risk for the two transformer groups are considered below.

SVTS 1266 (B12) Bus Group Summer Peak Forecasts

This bus group supplies Noble Park, Springvale South, Clarinda, Oakleigh East, Springvale and Springvale West zone substations owned by United Energy. Five generation units over 1 MW are connected at SVTS 1266 (B12) bus group.¹

The recorded peak demand in summer 2016 for the SVTS 1266 group was 227.1 MW (228.8 MVA). The load at SVTS 1266 (B12) is forecast to have a power factor of 0.989 at times of peak demand.

United Energy's new Keysborough zone substation was commissioned in 2014. Approximately 15 MW of demand was transferred away from SVTS to HTS. This load transfer is reflected in the graph below.

The graph below depicts the 10⁰ and 50⁰ percentile summer maximum demand for SVTS1266 and the corresponding rating with both transformers in service.

¹ The maximum demand forecasts adopted in this risk analysis exclude the impact of generation schemes.
The graph above shows that with both transformers in service, there is adequate capacity to meet the anticipated maximum demand for the entire planning period.

**SVTS 3466 (B34) Bus Group Summer Peak Forecasts**

This bus group supplies East Burwood, Glen Waverley and Notting Hill zone substations owned by United Energy and Riversdale zone substation owned by CitiPower. One generation unit over 1 MW is connected at SVTS 3466 (B34) bus group.\(^1\)

The recorded peak demand in summer 2015 for the SVTS 3466 group was 197.3 MW (200.1 MVA). The load at SVTS 3466 (B12) is forecast to have a power factor of 0.988 at times of peak demand.

The graph below depicts the 10\(^{th}\) and 50\(^{th}\) percentile summer maximum demand for SVTS3466 and the corresponding rating with both transformers in service.
The graph above shows that with both transformers in service, there is adequate capacity to meet the anticipated maximum demand for the entire planning period.

**Magnitude, probability and impact of loss of load**

The graph below depicts the 10th and 50th percentile total summer maximum demand forecasts together with the station’s expected operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.
The N rating on the graph indicates the maximum load that can be supplied from SVTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that the demand at SVTS 66 kV remains below the station's N rating within the ten year planning period. However, the 10th percentile overall summer maximum demand is forecast to exceed the station's (N-1) rating at 40°C from summer 2023, while the 50th percentile summer maximum demand is forecast to remain below its (N-1) rating.

The overall station load is forecast to have a power factor of 0.988 at times of peak demand. The demand at SVTS 66 kV is expected to exceed 95% of the 10th percentile peak demand for approximately 7 hours per annum in 2026.

The bar chart below depicts the energy at risk with one transformer out of service for the 10th percentile demand forecast, and the hours per year that the 10th percentile demand forecast is expected to exceed the N-1 capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 10th percentile demand forecast.

**Annual Energy and Hours at Risk at SVTS (Single Contingency Only)**

![Diagram showing energy and hours at risk with a line graph and bar chart]

**Comments on Energy at Risk**

For an outage of one transformer at SVTS, it is expected that from 2023, there would be insufficient capacity at the station to supply all demand at the 10th percentile temperature.

By the end of the ten-year planning period in 2026, the energy at risk under N-1 conditions is estimated to be 14 MWh at the 10th percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 7 hours in that year. The estimated value to customers of the 14 MWh of energy at risk in 2026 is approximately $0.53 million (based on a value of customer reliability of $36,632/MWh). In other words, at the 10th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of

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2 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
a forced outage, a major outage of one transformer at SVTS over the summer of 2026 would be anticipated to lead to involuntary supply interruptions that would cost consumers $0.53 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (14 MWh in 2026) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.1 MWh. This expected unserved energy is estimated to have a value to consumers of around $4,500 (based on a value of customer reliability of $36,632/MWh). AusNet Transmission Group has indicated that three of the four transformers at SVTS have an elevated failure rate due to the age and condition of the transformers. Therefore the expected unserved energy calculated above may underestimate the risk at this station. Given that AusNet Transmission Group plans to replace these transformers as part of its asset replacement program in 2021, the elevated failure rates are unlikely to advance any augmentation requirement at this terminal station.³

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of 10th percentile temperatures occurring in each year. Under 50th percentile temperature conditions, there is no energy at risk as maximum demand is within the station’s N-1 rating.

These key statistics for the year 2026 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
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</thead>
<tbody>
<tr>
<td>0</td>
<td>$0</td>
</tr>
<tr>
<td>0</td>
<td>$0</td>
</tr>
<tr>
<td>14</td>
<td>$0.53 million</td>
</tr>
<tr>
<td>0.1</td>
<td>$4,500</td>
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</table>

If one of the 220/66 kV transformers at SVTS is taken off line during peak loading times and the (N-1) station rating is exceeded, the OSSCA⁴ load shedding scheme which is operated by AusNet Transmission Group’s NOC⁵ will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy’s and CitiPower’s operational procedures after the operation of the OSSCA scheme.


⁴ Overload Shedding Scheme of Connection Asset.

⁵ Network Operations Centre
Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. Both United Energy and CitiPower have established and implemented the necessary plans that enable load transfers under contingency conditions via the 66 kV subtransmission and/or the high voltage 22 kV and 11 kV distribution networks. These plans are reviewed annually prior to the summer season. The total transfer capability away from SVTS 66 kV onto adjacent terminal stations via distribution network is assessed at 62 MVA for summer 2016-17.

2. Balance the bus group loads by transferring Clarinda and Oakleigh East zone substations from SVTS1266 to SVTS3466.

3. Establish a new 220/66 kV terminal station (DNTS) in the Dandenong area to off-load SVTS.

   In early 2012 United Energy submitted a preliminary connection enquiry to AEMO for the establishment of a new connection point in the Dandenong area. Joint planning activities have been underway between the two organisations to quantify the risk of the emerging constraints in the area and to assess viable options for alleviating the constraints. The investigations to date have identified that the need is driven mainly by load-at-risk associated with the 220 kV line constraints in the area. Utilising the latest maximum demand forecasts, this assessment suggests that the new terminal station and associated sub-transmission works are not likely to be economically justified within the ten year planning horizon.

   The capital cost of installing a new 220/66 kV terminal station in Dandenong is estimated to be in excess of $70 million. The cost of establishing, operating and maintaining the new assets would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $7 million.

   Further analysis, including a Regulatory Investment Test for Transmission will be undertaken at a later time to determine the preferred option for addressing the constraints, but at this stage a new 220/66 kV terminal station in Dandenong is the preferred network option to address the emerging constraints. United Energy will continue to work with AEMO on this joint planning exercise.

4. Install a third 225 MVA 220/66 kV transformer at Malvern terminal station (MTS) to off-load SVTS.

5. Install a fifth 150 MVA 220/66 kV transformer at SVTS.

6. Replace three of the four SVTS ‘B’ transformers in 2021, as part of AusNet Transmission Group’s asset replacement programme. AusNet Transmission Group intends to replace the existing transformers with like-for-like transformers. AusNet Transmission Group has indicated that the station’s (N-1) rating is expected to be similar to (or marginally higher than) the current level.
Preferred network option(s) for alleviation of constraints

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at SVTS under critical loading conditions:
   - maintain contingency plans to transfer load quickly to adjacent terminal stations;
   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any automatic load shedding that may take place; and
   - subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for metropolitan areas (refer to Section 5.5), this spare transformer can be used to temporarily replace the failed transformer.

2. Replace three of the four SVTS ‘B’ transformers in 2021, as part of AusNet Transmission Group’s asset replacement program.

3. Previous Transmission Connection Planning Reports proposed the rebalancing of bus group loads by transferring Clarinda and Oakleigh East zone substations from SVTS 1266 to SVTS 3466 at a capital cost of $2.5 million. However, given recent reductions in the maximum demand forecast compared to previous forecasts, and the planned completion of asset replacement works in 2021, this is unlikely to be economic on its own within the ten year planning horizon.

4. Establish a new 220/66 kV terminal station in the Dandenong area to off-load SVTS. This is the preferred option.

   On the present forecasts, establishment of a new terminal station in the Dandenong area is unlikely to be economically justified within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
SPRINGVALE TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (92.6%) and CitiPower (7.4%)
Station operational rating (N elements in service): 673 MVA via 4 transformers (Summer peaking)
Summer N-1 Station Rating: 505 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 560 MVA

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<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
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<td>$0.0k</td>
<td>$0.0k</td>
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<td>$0.0k</td>
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<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.1k</td>
<td>$0.4k</td>
<td>$0.7k</td>
</tr>
</tbody>
</table>

Notes:
1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
TEMPELSTOWE TERMINAL STATION (TSTS)

TSTS consists of three 150 MVA 220/66 kV transformers, and is the main source of supply for a major part of the north-eastern metropolitan area. The geographic coverage of the supply area spans from Eltham in the north to Canterbury in the south and from Donvale in the east to Kew in the west. The electricity supply network for this large region is split between United Energy, CitiPower, AusNet Electricity Services and Jemena Electricity Networks.

TSTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 357.6 MW (377.1 MVA) in summer 2009 under extreme weather conditions. The peak demand in summer 2016 was 297.6 MW (305 MVA). There is one embedded generation unit over 1 MW connected at TSTS.1

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.

The N rating on the chart indicates the maximum load that can be supplied from TSTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that the overall demand at TSTS remains below its N rating within the 10 year planning period. In addition, the 50th percentile summer peak demand is not expected to exceed the station’s (N-1) rating at 35°C and 40°C. However, the 10th percentile summer peak demand is forecast to exceed the station’s (N-1) rating at 35°C and 40°C from summer 2017.

1 The maximum demand forecasts adopted in this risk analysis exclude the impact of generation schemes.
The demand at TSTS 66 kV is expected to exceed 95% of the 50th percentile peak demand for approximately 3 hours per annum. The station load has a power factor of 0.974 at times of peak demand.

**Comments on Energy at Risk**

The graph on the previous page indicates that for an outage of one transformer at TSTS, it is expected that there would be sufficient capacity at the station to supply all demand at the 50th percentile temperature.

However, for an outage of one transformer at TSTS, it is expected that from summer 2017, there would be insufficient capacity at the station to supply all demand at the 10th percentile temperature. By the end of the ten-year planning period in 2026, the energy at risk under N-1 conditions is 32 MWh at the 10th percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 2 hours in that year. The estimated value to customers of the 32 MWh of energy at risk in 2026 is approximately $1.05 million (based on a value of customer reliability of $32,987/MWh). In other words, at the 10th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TSTS over the summer of 2026 would be anticipated to lead to involuntary supply interruptions that would cost consumers $1.05 million.

It is emphasised however, that the probability of a major outage of one of the three transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (32 MWh in 2026) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.2 MWh. This expected unserved energy is estimated to have a value to consumers of around $6,700 (based on a value of customer reliability of $32,987/MWh). AusNet Transmission Group has indicated that one of the three transformers at TSTS has an elevated failure rate due to the condition of the transformer. Therefore, the expected unserved energy calculated above may under-estimate the risk at this station. Given that AusNet Transmission Group plans to replace this transformer as part of its asset replacement programme in 2020, the elevated failure rates are unlikely to advance any augmentation requirements at this terminal station.

These key statistics for the year 2026 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th></th>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy at risk, at 50th percentile demand forecast</td>
<td>0</td>
<td>$0</td>
</tr>
<tr>
<td>Expected unserved energy at 50th percentile demand</td>
<td>0</td>
<td>$0</td>
</tr>
<tr>
<td>Energy at risk, at 10th percentile demand forecast</td>
<td>32</td>
<td>$1.05 million</td>
</tr>
<tr>
<td>Expected unserved energy at 10th percentile demand</td>
<td>0.2</td>
<td>$6,700</td>
</tr>
</tbody>
</table>

2 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.

If one of the 220/66 kV transformers at TSTS is taken off line during peak loading times and the (N-1) station rating is exceeded, the OSSCA\textsuperscript{4} load shedding scheme which is operated by AusNet Transmission Group’s TOC\textsuperscript{5} will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with each distribution company’s operational procedures after the operation of the OSSCA scheme.

In the case of TSTS supply at maximum loading periods, the OSSCA scheme would shed about 65 MW of load, affecting approximately 26,000 customers in 2017.

**Feasible options for alleviation of constraints**

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy, CitiPower, AusNet Electricity Services and Jemena Electricity Networks have established and implemented the necessary plans that enable load transfers under contingency conditions. These plans are reviewed annually prior to the summer season. The total transfer capability away from TSTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 17 MVA for summer 2016-17.

2. Establish a new 220/66 kV terminal station. Two terminal station sites, one in Doncaster (DCTS) and another in Kew (KWTS), have been reserved for possible future electrical infrastructure development to meet customers’ needs in the area. With established 220 kV tower lines to both sites, development of either of these sites could be economic depending upon the geographical location of additional customer load.

3. Install a fourth 150 MVA 220/66 kV transformers at TSTS. There is provision in the yard for an additional transformer.

The capital cost of installing a 220/66 kV transformer at TSTS 66 kV is estimated to be $20 million. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately $2.0 million.

On the present maximum demand forecasts, the fourth 220/66 kV transformer is not likely to be required within the ten year planning horizon.

**Preferred network option(s) for alleviation of constraints**

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at TSTS under critical loading conditions:
   - maintain contingency plans to transfer load quickly to adjacent terminal stations;
   - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place; and

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\textsuperscript{4} Overload Shedding Scheme of Connection Asset.
\textsuperscript{5} Transmission Operations Centre.
• subject to the availability of AusNet Transmission Group's spare 220/66 kV transformer for metropolitan areas (refer to Section 5.5), this spare transformer can be used to temporarily replace the failed transformer.

2. Install a fourth 150 MVA 220/66 kV transformers at TSTS.

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at TSTS, it is proposed to install a fourth 220/66 kV transformer at TSTS. On the present forecasts, an additional 220/66 kV transformer is unlikely to be economic within the ten year planning horizon.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
## TEMPLESTOWE TERMINAL STATION 66 kV

**Detailed data: Magnitude and probability of loss of load**

**Distribution Businesses supplied by this station:**
- United Energy (35%)
- CitiPower (34%)
- AusNet Electricity Services (22%)
- Jemena (9%)

**Station operational rating (N elements in service):**
- 549 MVA via 3 transformers (Summer peaking)

**Summer N-1 Station Rating:**
- 366 MVA [See Note 1 below for interpretation of N-1]

**Winter N-1 Station Rating:**
- 417 MVA

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<td>50th percentile Summer Maximum Demand (MVA)</td>
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<td>50th percentile Winter Maximum Demand (MVA)</td>
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<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 50th percentile demand</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
<td>$0.0k</td>
</tr>
<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
<td>$4.3k</td>
<td>$3.6k</td>
<td>$3.4k</td>
<td>$2.8k</td>
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<td>$3.2k</td>
<td>$4.1k</td>
<td>$5.4k</td>
<td>$6.7k</td>
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<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value</td>
<td>$1.3k</td>
<td>$1.1k</td>
<td>$1.0k</td>
<td>$0.8k</td>
<td>$0.8k</td>
<td>$1.0k</td>
<td>$1.2k</td>
<td>$1.6k</td>
<td>$2.0k</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
1. “N-1” means cyclic station output capability rating with outage of one transformer. For 50th percentile value, the rating is at an ambient temperature of 35 degrees Centigrade. For 10th percentile value, the rating is at an ambient temperature of 40 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)).
TERANG TERMINAL STATION (TGTS) 66kV

Terang Terminal Station (TGTS) 66 kV consists of one 125 MVA transformer and one 150 MVA 220/66 kV transformer and is the main source of supply for over 78,406 customers in Terang and the surrounding area. The terminal station supply area includes Terang, Colac, Camperdown, Cobden, Warrnambool, Koroit, Portland and Hamilton.

Magnitude, probability and impact of loss of load

The station rating was revised by AusNet Transmission Group in 2011. This step change in station cyclic rating is depicted in the graph below.

TGTS 66 kV demand has recently become winter peaking but peaks can occur in summer or spring (depending upon the dairy industry load). Growth in winter peak demand at TGTS has averaged around 1.5 MW or 0.9% per annum over the last 5 years. The metered peak load on the station reached 180.2 MW (182.1 MVA) in winter 2015.

It is estimated that:
- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.99.

The graph below depicts the 10th and 50th percentile winter maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” winter rating at 5°C.

The (N) rating on the chart indicates the maximum load that can be supplied from TGTS with all transformers in service.
The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

Comments on Energy at Risk

For an outage of one transformer at TGTS, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 582 hours in 2022. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 10,739 MWh in 2022. The estimated value to consumers of the 10,739 MWh of energy at risk is approximately $422.3 million (based on a value of customer reliability of $39,325 per MWh). In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TGTS in 2022 would be anticipated to lead to involuntary supply interruptions that would cost consumers $422.3 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, while the expected unavailability per transformer per annum is 0.217%. When the energy at risk (10,739 MWh for 2022) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 46.5 MWh. This expected unserved energy is estimated to have a value to consumers of around $1.83 million (based on a value of customer reliability of $39,325 per MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50th percentile) winter temperatures occurring in each year. Under 10th percentile temperature conditions, the energy at risk in

1 The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
2022 is estimated to be 15,118 MWh. The estimated value to consumers of this energy at risk in 2022 is approximately $595 million. The corresponding value of the expected unserved energy (of 65.5 MWh) is $2.58 million.

Key statistics relating to energy at risk and expected unserved energy for the year 2022 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>10,739</td>
<td>$422.3 million</td>
</tr>
<tr>
<td>46.5</td>
<td>$1.83 million</td>
</tr>
<tr>
<td>15,118</td>
<td>$595 million</td>
</tr>
<tr>
<td>65.5</td>
<td>$2.58 million</td>
</tr>
</tbody>
</table>

**Feasible options for alleviation of constraints**

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

- Replacing the #2 125 MVA 220/66 kV transformer at TGTS with a 150 MVA unit. For an indicative installation cost of $14 million this option will most likely prove to be uneconomic as it only provides a marginal increase in station capacity, hence necessitating additional capacity augmentation shortly afterwards.

- Installation of a third 220/66 kV transformer (150 MVA) at TGTS at an indicative capital cost of $18 million.

- Demand reduction: There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction would depend on the customer uptake and would be taken into consideration when determining the optimum timing for any future capacity augmentation.

- Embedded generation: Connection of wind farm generation into the 66 kV infrastructure ex-TGTS has been implemented. Codrington wind farm (18.2 MW) was commissioned in 2001 and this combined with Yambuk wind farm (30 MW) in 2005, Oakland’s Hill wind farm (63 MW) in 2011 and Morton’s Lane wind farm (19.5 MW) in 2012, provides a total wind generation capacity of 130 MW. Additional wind generation is being investigated in the area supplied by TGTS and this may defer any capacity augmentation planned for TGTS. Historically however, it has been observed that at times of peak demand, the level of wind generation has been relatively small, at approximately 4% of peak demand.

- There are presently several large embedded generation 66 kV wind farm proposals in the area which may drive the need for an additional 150 MVA 220/66 kV transformer at TGTS to accommodate the reverse power flow expected at TGTS.
Possible uptake of battery storage in the future could provide some contribution to supporting the peak load.

**Preferred option(s) for alleviation of constraints**

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at TGTS, it is proposed to:

1. Install a third 220/66 kV transformer (150 MVA) at TGTS. On the basis of a combination of the 10th and 50th demand forecast scenarios, and using the 2016 VCR estimate, the transformer would not be expected to be required before 2022 to support the critical peak demand. However, applying AEMO's previous (higher) VCR estimate, the installation of a third transformer by 2019 would be assessed as being economic. Powercor will continue to monitor peak demand at TGTS, and may initiate more detailed analysis of the value of customer reliability in the TGTS supply area, to determine the optimal timing of any augmentation or other corrective action. As already noted, the timing of augmentation is also likely to be influenced by any further large scale wind farm developments in the area.

2. As a temporary measure, maintain contingency plans to transfer load quickly to the Geelong Terminal Station (GTS) by the use of the 66 kV tie lines between TGTS and GTS in the event of an unplanned outage of one transformer at TGTS under critical loading conditions. This load transfer is in the order of 18 MVA. Under these temporary measures, affected customers would be supplied from the 66 kV tie line infrastructure on a radial network, thereby reducing their level of reliability.

3. Subject to the availability of an AusNet Transmission Group’s spare 220/66 kV transformer for rural areas (refer Section 5.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

The capital cost of installing a 150 MVA 220/66 kV transformer at TGTS is estimated to be $18 million. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is $1.8 million. This cost provides a broad upper bound indication of the maximum contribution from distributors which may be available to embedded generators or customers to reduce forecast demand and defer or avoid the transmission connection component of this augmentation.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
TGTS Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)

MVA

Normal cyclic rating with all plant in service 332 via 2 transformers (summer)
Summer N-1 Station Rating: 166 [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 185

<table>
<thead>
<tr>
<th></th>
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<tr>
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<td>195.3</td>
<td>197.5</td>
<td>197.8</td>
<td>198.3</td>
<td>195.9</td>
<td>196.4</td>
<td>196.9</td>
<td>195.9</td>
<td>196.0</td>
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<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>229.0</td>
<td>237.3</td>
<td>244.6</td>
<td>250.7</td>
<td>255.5</td>
<td>260.3</td>
<td>266.0</td>
<td>270.2</td>
<td>274.2</td>
<td>278.3</td>
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<td>10th percentile Summer Maximum Demand (MVA)</td>
<td>213.9</td>
<td>217.2</td>
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<td>214.3</td>
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<tr>
<td>10th percentile Winter Maximum Demand (MVA)</td>
<td>234.3</td>
<td>242.7</td>
<td>250.4</td>
<td>257.0</td>
<td>261.8</td>
<td>266.9</td>
<td>272.7</td>
<td>277.0</td>
<td>280.8</td>
<td>285.0</td>
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<td>N-1 energy at risk at 50th percentile demand (MWh)</td>
<td>1834.7</td>
<td>3281.7</td>
<td>5062.2</td>
<td>6923.4</td>
<td>8716.9</td>
<td>10739.3</td>
<td>13600.5</td>
<td>16019.3</td>
<td>18471.6</td>
<td>21289.1</td>
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<td>242.3</td>
<td>335.8</td>
<td>422.3</td>
<td>502.3</td>
<td>592.0</td>
<td>688.3</td>
<td>772.8</td>
<td>550.0</td>
<td>934.0</td>
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<td>N-1 energy at risk at 10th percentile demand (MWh)</td>
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<td>8144.8</td>
<td>10624.2</td>
<td>12620.5</td>
<td>15118.1</td>
<td>18492.3</td>
<td>21341.6</td>
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<td>N-1 hours at risk at 10th percentile demand (hours)</td>
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<td>493.3</td>
<td>601.3</td>
<td>677.5</td>
<td>767.5</td>
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<td>966.0</td>
<td>1042.8</td>
<td>1134.8</td>
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<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
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<td>30.00</td>
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<td>58.96</td>
<td>69.42</td>
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<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
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<td>24.90</td>
<td>35.29</td>
<td>46.04</td>
<td>54.69</td>
<td>65.51</td>
<td>80.13</td>
<td>92.48</td>
<td>104.24</td>
<td>118.23</td>
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<td>$0.56M</td>
<td>$1.86M</td>
<td>$1.18M</td>
<td>$1.49M</td>
<td>$1.83M</td>
<td>$2.32M</td>
<td>$2.73M</td>
<td>$3.15M</td>
<td>$3.83M</td>
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<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
<td>$0.63M</td>
<td>$0.98M</td>
<td>$1.38M</td>
<td>$1.81M</td>
<td>$2.15M</td>
<td>$2.50M</td>
<td>$3.15M</td>
<td>$3.64M</td>
<td>$4.10M</td>
<td>$4.65M</td>
</tr>
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<td>$0.41M</td>
<td>$0.69M</td>
<td>$1.02M</td>
<td>$1.37M</td>
<td>$1.69M</td>
<td>$2.05M</td>
<td>$2.57M</td>
<td>$3.00M</td>
<td>$3.43M</td>
<td>$3.93M</td>
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</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. “Expected unserved energy” means “N-1 energy at risk” for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
THOMASTOWN TERMINAL STATION 66 kV (TTS 66 kV)

Thomastown Terminal Station (TTS) is located in the north of greater Melbourne. It operates at 220/66 kV and supplies Jemena Electricity Networks and AusNet Electricity Services customers in the Thomastown, Coburg, Preston, Watsonia, North Heidelberg, Lalor, Coolaroo and Broadmeadows areas.

Background

TTS has five 150 MVA transformers and is a summer critical station. Under system normal conditions, the No.1 & No.2 transformers are operated in parallel as one group (TTS(B12)) and supply the No.1 & No.2 66 kV buses. The No.3, No.4 & No.5 transformers are operated in parallel as a separate group (TTS(B34)) and supply the No.3 & No.4 66 kV buses. The 66 kV bus 2-3 and bus 1-4 tie circuit breakers are operated open to limit the maximum prospective fault levels on the four 66 kV busses to within the switchgear ratings.

For an unplanned transformer outage in the TTS(B12) group, the No.5 transformer will automatically change over to the TTS(B12) group. Therefore, an unplanned transformer outage of any one of the five transformers at TTS will result in both the TTS(B12) & TTS(B34) groups being comprised of two transformers each. Given this configuration, load demand on the TTS(B12) group must be kept within the capabilities of the two transformers at all times or load shedding may occur.

Transformer group TTS (B12) Summer Peak Forecasts

The graph below depicts the summer maximum demand forecasts (for 50th and 10th percentile temperatures) for TTS (B12) and the corresponding rating with both transformers (B1 & B2) operating. It is estimated that:

- For 7 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.96.

The graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand for the entire forecast period. As explained above, if an unplanned transformer outage in the TTS(B12) group occurs, the No.5 transformer will automatically change over to the TTS(B12) group. In effect then, the N-1 and N ratings of the TTS(B12) group are equivalent. Thus there is sufficient capacity provided by the TTS(B12) group to meet the anticipated maximum demand for the entire forecast period, even under a transformer outage condition.
Transformer group TTS (B34) Summer Peak Forecasts

The graph below depicts the TTS (B34) rating with all transformers (B3, B4 & B5) in service ("N" rating), and with one of the three transformers out of service ("N-1" rating), along with the 50\textsuperscript{th} and 10\textsuperscript{th} percentile summer maximum demand forecasts. It is estimated that:

- For 5 hours per year, 95\% of peak demand is expected to be reached under the 50\textsuperscript{th} percentile demand forecast.
- The station load power factor at the time of peak demand is 0.92.
The above graph shows that with one transformer out of service, there is adequate capacity to meet the anticipated maximum load demand at TTS (B34) for the entire forecast period.

Based on the above analysis of both transformer groups, the need for augmentation of transmission connection assets at TTS 66 kV is not expected to arise over the next ten years.

The table on the following page provides more detailed data on the station rating and demand forecasts.
THOMASTOWN TERMINAL STATION (B12 TRANSFORMER GROUP)

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: JEN (43%), AusNet Electricity Services (57%)

Normal cyclic rating with all plant in service: 325 MVA (Summer peaking)

Summer N-1 Station Rating: 325 MVA [See note 1 below for interpretation on N-1]

Winter N-1 Station Rating: 356 MVA

<table>
<thead>
<tr>
<th>Station: TTS (B12)</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
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<tbody>
<tr>
<td>50(^{th}) percentile Summer Maximum Demand (MVA)</td>
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<td>229</td>
<td>226</td>
<td>222</td>
<td>220</td>
<td>217</td>
<td>219</td>
<td>220</td>
<td>223</td>
<td>226</td>
</tr>
<tr>
<td>50(^{th}) percentile Winter Maximum Demand (MVA)</td>
<td>185</td>
<td>187</td>
<td>188</td>
<td>189</td>
<td>188</td>
<td>189</td>
<td>191</td>
<td>191</td>
<td>192</td>
<td>194</td>
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<tr>
<td>10(^{th}) percentile Summer Maximum Demand (MVA)</td>
<td>262</td>
<td>257</td>
<td>254</td>
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<td>248</td>
<td>247</td>
<td>248</td>
<td>250</td>
<td>254</td>
<td>258</td>
</tr>
<tr>
<td>10(^{th}) percentile Winter Maximum Demand (MVA)</td>
<td>191</td>
<td>193</td>
<td>195</td>
<td>196</td>
<td>196</td>
<td>197</td>
<td>199</td>
<td>201</td>
<td>202</td>
<td></td>
</tr>
<tr>
<td>N-1 energy at risk at 50th percentile demand (MWh)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>N-1 hours at risk at 50th percentile demand (hours)</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
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<td>0</td>
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<tr>
<td>N-1 energy at risk at 10th percentile demand (MWh)</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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</tr>
<tr>
<td>N-1 hours at risk at 10th percentile demand (hours)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
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<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
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<td>0.0</td>
<td>0.0</td>
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<td>0.0</td>
<td>0.0</td>
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<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value</td>
<td>$ - M$</td>
<td>$ - M$</td>
<td>$ - M$</td>
<td>$ - M$</td>
<td>$ - M$</td>
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</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx).
THOMASTOWN TERMINAL STATION (B34 TRANSFORMER GROUP)

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: JEN (100%), AusNet Electricity Services (0%)
Normal cyclic rating with all plant in service: 500 MVA (Summer peaking)
Summer N-1 Station Rating: 340 MVA [See note 1 below for interpretation on N-1]
Winter N-1 Station Rating: 397 MVA

<table>
<thead>
<tr>
<th>Station: TTS (B34)</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
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<td>279</td>
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<td>287</td>
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</tr>
<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
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<td>10th percentile Winter Maximum Demand (MVA)</td>
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<tr>
<td>N-1 hours at risk at 50th percentile demand (hours)</td>
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<td>N-1 hours at risk at 10th percentile demand (hours)</td>
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<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
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<tr>
<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
<td>0.0</td>
<td>0.0</td>
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</tr>
<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value</td>
<td>$ - M</td>
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<td>$ - M</td>
</tr>
</tbody>
</table>

Notes:
1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx).
TYABB TERMINAL STATION (TBTS)

TBTS consists of three 150 MVA 220/66 kV transformers, and is the main source of supply for over 115,000 customers on the Mornington Peninsula. The geographic coverage of the area spans from Frankston South in the north to Portsea in the south.

TBTS 66 kV is a summer critical station. Summer peak demand at TBTS generally occurs on days of high ambient temperature during the summer holiday period (from mid-December to the end of January). Given the peak demand at TBTS is directly related to air-conditioning use during the holiday periods along the coastal belt of the Mornington Peninsula during summer, the peak is very sensitive to the maximum ambient temperature at this time. The station reached its second highest recorded peak demand of 281.1 MW (289.1 MVA) on 31 December 2015, which was 23.3 MW (23.9 MVA) higher than the 2014-15 maximum demand. For TBTS the historic peak demand of 283.4 MW (298.0 MVA) was recorded on 29 January 2009. There are two embedded generation units over 1 MW connected at TBTS.

TBTS has exceeded its N-1 thermal rating since summer 2004 as a result of load transfers from East Rowville (ERTS) and Heatherton (HTS) terminal stations. Over the period since 2004, had a transformer outage occurred at TBTS, the capacity of the remaining transformer would have been insufficient to supply the total connected demand at TBTS. The amount of energy at risk has gradually increased over time with demand growth in the area. As a result, a Regulatory Test was undertaken in 2011, which identified the installation of a third 150 MVA 220/66 kV transformer as the most economic network solution. A new third transformer was installed at TBTS and commissioned in November 2013.

Magnitude, probability and impact of loss of load

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational N rating (all transformers in service) and the N-1 rating at 35°C as well as 40°C ambient temperature.

The N rating on the chart below indicates the maximum load that can be supplied from TBTS with all transformers in service. Exceeding this level will initiate AusNet Transmission Group’s automatic load shedding scheme.

The graph indicates that the demand at TBTS remains below its N rating within the 10 year planning period. However, the 10th percentile summer maximum demand is forecast to exceed the station’s (N-1) rating at 40°C from summer 2025. The 50th percentile summer maximum demand is expected to remain within the (N-1) rating for the entire planning period.

The station load is forecast to have a power factor of 0.972 at times of peak demand. The demand at TBTS is expected to exceed 95% of the 50th percentile peak demand for approximately 5 hours per annum.

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1 The maximum demand forecasts adopted in this risk analysis exclude the impact of generation schemes.
Comments on Energy at Risk

The below table indicates that for an outage of one transformer at TBTS, it is expected that there would be sufficient capacity at the station to supply all demand at the 50\textsuperscript{th} percentile temperature.

However, for an outage of one transformer at TBTS, it is expected that from summer 2025, there would be insufficient capacity at the station to supply all demand at the 10\textsuperscript{th} percentile temperature. By the end of the ten-year planning period in 2026, the energy at risk under N-1 conditions is 17 MWh at the 10\textsuperscript{th} percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 2 hours in that year. The estimated value to customers of the 17 MWh of energy at risk in 2026 is approximately $0.5 million (based on a value of customer reliability of $31,591/MWh\textsuperscript{2}). In other words, at the 10\textsuperscript{th} percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TBTS over the summer of 2026 would be anticipated to lead to involuntary supply interruptions that would cost consumers $0.5 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0\% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217\%. When the energy at risk (17 MWh in 2026) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.1 MWh. This expected unserved energy is estimated to have a value to consumers of around $3,500 (based on a value of customer reliability of $31,591/MWh).
These key statistics for the year 2026 under N-1 outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>Energy at risk, at 50\textsuperscript{th} percentile demand forecast</th>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected unserved energy at 50\textsuperscript{th} percentile demand</td>
<td>0.0</td>
<td>0</td>
</tr>
<tr>
<td>Energy at risk, at 10\textsuperscript{th} percentile demand forecast</td>
<td>17</td>
<td>$0.5 million</td>
</tr>
<tr>
<td>Expected unserved energy at 10\textsuperscript{th} percentile demand</td>
<td>0.1</td>
<td>$3,500</td>
</tr>
</tbody>
</table>

**Feasible options for alleviation of constraints**

The following option is technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy has established and implemented the necessary plans that enable load transfers under contingency conditions, via both 66 kV sub-transmission and 22 kV distribution networks. These plans are reviewed annually prior to the summer season. Transfer capability away from TBTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 22 MVA for summer 2017.

Given that the 50\textsuperscript{th} percentile demand forecast is expected to remain below the N-1 rating of the station, no energy will be at risk for a single transformer outage based on the current 50\textsuperscript{th} percentile demand forecast for the foreseeable future. The expected unserved energy under the 10\textsuperscript{th} percentile demand forecast is not significant over the ten year planning horizon. Moreover, the load at risk after summer 2026 can be managed operationally by transferring load under contingency via the distribution network.

On the basis of the current forecasts, no major demand related augmentation is planned at TBTS over the next ten years.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy.
TYABB TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy (100%)
Station operational rating (N elements in service): 519 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Rating: 348 MVA via 2 transformers [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating: 397 MVA via 2 transformers

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<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>286</td>
<td>283</td>
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<td>50th percentile Winter Maximum Demand (MVA)</td>
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<td>N-1 hours at risk at 50th percentile demand (hours)</td>
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<td>N-1 hours at risk at 10th percentile demand (hours)</td>
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<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
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Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
WEMEN TERMINAL STATION (WETS)

Wemen Terminal Station (WETS) is a new station which was commissioned in February 2012. WETS consists of one 70 MVA 235/66 kV transformer supplying part of the 66 kV network previously supplied by RCTS. This configuration is the main source of supply for approximately 6,121 customers in the Wemen and Ouyen areas. The station supply area includes Wemen, Robinvale and Ouyen.

Magnitude, probability and impact of loss of load

WETS demand is summer peaking. The peak load for the 66 kV network on the station reached 49.6 MW in summer 2016.

It is estimated that:

- For 9 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.99.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature. As WETS has only one transformer the “N-1” rating is zero.

The bar chart below depicts the energy at risk with the single transformer out of service, after implementation of the contingency plan to transfer 29 MVA of load away to RCTS, for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. As explained in section 4.6, for the purpose of the Transmission Connection Planning Report, short-term load transfer capability is not taken into account directly in the estimation of expected unserved energy in the event of a major failure of a transformer. The one exception to this approach is WETS, which is...
the only single transformer station considered in the Transmission Connection Planning Report. WETS was planned on the basis that some load transfer capability at 66 kV would be available to Red Cliffs Terminal Station (RCTS66) in the event of a transformer outage. Accordingly, the risk assessment for Wemen takes into account the load forecasts for RCTS66 and an assessment of the post-contingent load transfer capability.

The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

![Graph showing annual energy at risk at WETS](image)

**Comments on Energy at Risk**

For a major outage of the single transformer at WETS a contingency plan will be implemented to transfer 29 MVA of load from WETS to RCTS. After taking this load transfer into account, there will be insufficient capacity at the station to supply all remaining demand at the 50th percentile temperature for about 408 hours in 2026. The energy at risk at the 50th percentile temperature under N-1 conditions, after load transfers, is estimated to be 2,335 MWh in 2026. The estimated value to consumers of the 2,335 MWh of energy at risk is approximately $102 million (based on a value of customer reliability of $43,703/MWh)\(^1\). In other words, at the 50th percentile demand level, after transferring load away but in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of the transformer at WETS in 2026 would be anticipated to lead to involuntary supply interruptions that would cost consumers $102 million.

It is emphasised however, that the probability of a major outage of the transformer occurring over the year is very low at 1% per annum, whilst the expected annual unavailability of the transformer is 0.217%. When the energy at risk (2,335 MWh for 2026) is weighted by this low unavailability, the expected unsupplied energy is estimated to be 5.1 MWh. This expected unserved energy is estimated to have a value to consumers of around $0.22 million (based on a value of customer reliability of $43,704/MWh).

\(^1\) The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50\textsuperscript{th} percentile) summer temperatures occurring in each year\textsuperscript{2}. Under 10\textsuperscript{th} percentile summer temperature conditions, the energy at risk in 2026 is estimated to be 5,125 MWh. The estimated value to consumers of this energy at risk in 2026 is approximately $224 million. The corresponding value of the expected unserved energy (11.1 MWh in 2026) is $0.49 million.

These key statistics for the year 2026 under N-1 outage conditions after 29 MVA of load transfers away are summarised in the table below.

<table>
<thead>
<tr>
<th></th>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy at risk, at 50\textsuperscript{th} percentile demand forecast</td>
<td>2,335</td>
<td>$102 million</td>
</tr>
<tr>
<td>Expected unserved energy at 50\textsuperscript{th} percentile demand</td>
<td>5.1</td>
<td>$0.22 million</td>
</tr>
<tr>
<td>Energy at risk, at 10\textsuperscript{th} percentile demand forecast</td>
<td>5,125</td>
<td>$224 million</td>
</tr>
<tr>
<td>Expected unserved energy at 10\textsuperscript{th} percentile demand</td>
<td>11.1</td>
<td>$0.49 million</td>
</tr>
</tbody>
</table>

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint:

- Installation of an additional 70 MVA 235/66 kV transformer at WETS.
- Lower cost options to reduce the load at risk at WETS are being investigated.
- However, there are presently several proposals to connect large embedded solar farms to the 66 kV system in the area. This may drive the need for additional transformer capacity at WETS to accommodate the reverse power flow expected at the station.
- Demand reduction: There is an opportunity for voluntary demand reduction to reduce loading at the station during times of network constraint.

Preferred option(s) for alleviation of constraints

As already noted, a contingency plan to transfer 29 MVA of load to RCTS using the 66 kV network between WETS and RCTS will be implemented in the event of the loss of WETS, which is a single transformer station. Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for rural areas (refer to Section 5.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

On the basis of the 10\textsuperscript{th} percentile demand forecast scenario, after transfers back to RCTS are taken into account, it is expected that the installation of additional capacity at WETS will not be economically justified in the current planning period. As previously mentioned however, the connection of additional large embedded generation to the 66 kV system in the area may drive the need for additional transformer capacity at WETS to accommodate

\textsuperscript{2} As noted in Section 4.1, the 50\textsuperscript{th} percentile demand forecast is used in each year.
reverse power flows. It has not yet been determined whether any such need would be met through the installation of a larger single transformer to replace the existing one, or the installation of a second 70 MVA transformer in parallel with the existing one. It is noted that under the first option, no additional N-1 capacity would be provided as WETS would remain a single transformer station. Powercor is therefore continuing to investigate other lower cost options to reduce the load at risk.

It is noted that the total capital cost of installing an additional 70 MVA 235/66 kV transformer at WETS is estimated to be $14 million, which equates to an annual cost of $1.4 million. The annual cost of the network solution provides a broad upper bound indication of the maximum contribution from distributors for non-network solutions.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy. The energy at risk, hours at risk and expected unserved energy are after implementation of the contingency plan to transfer load to RCTS.
Wemen Terminal Station

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (100%)

Normal cyclic rating with all plant in service
77 MVA via 1 transformer

Summer N-1 Station Rating:
0 MVA [See Note 1 below for interpretation of N-1]

Winter N-1 Station Rating:
0 MVA

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<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>51.2</td>
<td>52.1</td>
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<td>35.3</td>
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<td>35.6</td>
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<td>N-1 energy at risk at 50% percentile demand (MWh)</td>
<td>798.8</td>
<td>983.8</td>
<td>1178.9</td>
<td>1402.8</td>
<td>1850.2</td>
<td>1710.1</td>
<td>1985.7</td>
<td>2244.3</td>
<td>2156.1</td>
<td>2334.3</td>
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<td>N-1 hours at risk at 50th percentile demand (hours)</td>
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<td>213.0</td>
<td>244.8</td>
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<td>360.5</td>
<td>396.3</td>
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<td>N-1 energy at risk at 10% percentile demand (MWh)</td>
<td>2624.9</td>
<td>2949.5</td>
<td>3278.9</td>
<td>3678.2</td>
<td>4249.6</td>
<td>4166.2</td>
<td>4450.1</td>
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<td>N-1 hours at risk at 10th percentile demand (hours)</td>
<td>442.5</td>
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<td>638.0</td>
<td>670.8</td>
<td>670.3</td>
<td>701.0</td>
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<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
<td>1.73</td>
<td>2.13</td>
<td>2.55</td>
<td>3.04</td>
<td>4.01</td>
<td>3.71</td>
<td>4.30</td>
<td>4.86</td>
<td>4.67</td>
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<td>Expected Unserved Energy at 10th percentile demand (MWh)</td>
<td>5.69</td>
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<td>7.10</td>
<td>7.97</td>
<td>9.21</td>
<td>9.03</td>
<td>9.64</td>
<td>10.42</td>
<td>10.40</td>
<td>11.10</td>
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<td>Expected Unserved Energy value at 50th percentile demand</td>
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<td>$0.09M</td>
<td>$0.11M</td>
<td>$0.13M</td>
<td>$0.18M</td>
<td>$0.16M</td>
<td>$0.19M</td>
<td>$0.21M</td>
<td>$0.20M</td>
<td>$0.22M</td>
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<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
<td>$0.25M</td>
<td>$0.28M</td>
<td>$0.31M</td>
<td>$0.35M</td>
<td>$0.40M</td>
<td>$0.39M</td>
<td>$0.42M</td>
<td>$0.46M</td>
<td>$0.45M</td>
<td>$0.49M</td>
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<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
<td>$0.13M</td>
<td>$0.15M</td>
<td>$0.17M</td>
<td>$0.20M</td>
<td>$0.24M</td>
<td>$0.23M</td>
<td>$0.26M</td>
<td>$0.29M</td>
<td>$0.28M</td>
<td>$0.30M</td>
</tr>
</tbody>
</table>

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating after load transfers away.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating after load transfers away. As the WETS “N-1” rating is zero the load always exceeds the N-1 capacity before load transfers away.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx).
WEST MELBOURNE TERMINAL STATION 22 kV (WMTS 22 kV)

WMTS 22 kV is a summer critical station consisting of two 165 MVA 220/22 kV transformers, which supplies 24,004 customers in CitiPower’s distribution network. The terminal station provides major 22 kV supply to the West Melbourne area including Melbourne Docks, Docklands Areas, North Melbourne (including a railway substation), Parkville and Carlton, and the northern and western inner Central Business District and surrounding areas.

A new 66/11 kV zone substation (BQ) was established in 2011. BQ zone substation is supplied via WMTS 66 kV and partly offloaded WMTS 22 kV over 2012 – 2014. It is planned to supply BQ from Brunswick Terminal Station (BTS 66 kV) when that station is established in late 2016.

To enable the planned decommissioning of WMTS 22 by 2023, further offloads from the station are planned to occur to both BTS 66 (when established) and WMTS 66 over the next 6 years. These offloads are shown in the WMTS 22 load forecast below.

The peak load on the station reached 66.7 MW in summer 2015/16. It is estimated that:

- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.95.

Magnitude, probability and impact of loss of load

The graph below depicts the station’s operational N rating for all transformers in service and the N-1 rating (at 35 and 40 degrees ambient temperature), and the latest 10th and 50th percentile maximum demand forecasts for the next ten years. The N-1 ratings are restricted by over-voltage limits on transformer tapping.

The graph shows that there is sufficient capacity at the station to supply the forecast 50th and 10th percentile demands over the forecast period, even with one transformer out of service. As noted above, it is planned that all WMTS 22 kV load will be offloaded to WMTS 66 kV and future BTS 66 kV before 2023. As part of its asset renewal program, AusNet Transmission Group plans to retire all of the existing WMTS 22 kV systems by the end of 2023.
WEST MELBOURNE TERMINAL STATION 66 kV (WMTS 66 kV)

WMTS 66 kV is a summer critical station consisting of four 150 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (85.0%) and Jemena Electricity Networks (15.0%). The terminal station provides major supply for 86,854 customers in the western Central Business District, including Docklands areas, as well as the inner suburbs of Northcote and Brunswick West in the north, and Kensington, Flemington, Footscray and Yarraville in the west.

WMTS 66 kV is operating with one of the four transformers on “Normal Open Auto-close” duty (i.e. on hot stand-by with a facility for automatic closing upon forced outage of any one of the three normal-running transformers). This arrangement facilitates control of the 66 kV fault level to within the terminal station fault level rating. With this transformer operating arrangement, the N rating will be approximately equal to the N-1 rating (i.e. equal to the capacity of three transformers), thus imposing a restriction that the terminal station should not be loaded beyond the N-1 rating at any time.

Following the extremely hot summer in 2009, AusNet Transmission Group expressed concern regarding the operating temperature of the WMTS 220/66 kV transformers. In order to avoid operating the WMTS transformers at temperatures that would result in accelerated aging, AusNet Transmission Group has reduced the WMTS Terminal Station summer cyclic ratings by about 5.5% to 497 MVA at 35°C ambient temperature and about 10% to 463 MVA at 43°C ambient temperature. As part of its asset renewal program, AusNet Transmission Group plans to replace all four existing 150 MVA 220/66 kV transformer units (B1, B2, B3 and B4) with three 225 MVA transformer units by the end of 2021.

The peak load on the station reached 419.2 MW (430.2 MVA) in summer (February) 2016.

It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at time of peak demand is 0.97.

**Magnitude, probability and impact of loss of load**

The graph below depicts the station’s N-1 rating (approximately equal to the N rating) at 35°C and 43°C, and the latest 10th and 50th percentile maximum demand forecasts during the summer periods over the next ten years. The forecast demands include the effects of load transfer works¹ which were undertaken after the establishment of BTS 66 kV in late 2016. It also includes the further planned transfers² from WMTS 22 to WMTS 66 between 2019 and 2021 prior to the planned decommissioning of the 22 kV supply from WMTS.

---

¹ WA (52.4 MW), BQ (50.3 MW) and VM (40.8 MW) transfer from WMTS 66 to BTS 66 in late 2016.
² J (11.7 MW) transfer from WMTS 22 to WMTS 66 in 2019, VR (9.3 MW) and DA (34.3 MW) transfer from WMTS 22 to WMTS 66 in 2021.
The graph shows that there is sufficient capacity at WMTS 66 kV to supply the forecast 10th percentile and 50th percentile demand over the planning period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.
WODONGA TERMINAL STATION (WOTS 66 kV and 22 kV)

Wodonga Terminal Station is the main source of supply for a significant part of north-eastern Victoria. The supply is via two 330/66/22 kV three-winding transformers with a nominal rating of 75 MVA each.

This terminal station supplies Wodonga centrally as well as the area from Rutherglen in the west to Corryong in the east. The Hume Power Station (HPS) is connected to the WOTS 66 kV bus and can supply up to 58 MVA into the WOTS 66 kV bus, offsetting the load on the transformers.

AusNet Electricity Services is responsible for planning the transmission connection and distribution network for this region.

Magnitude, probability and impact of loss of load

WOTS is a summer peaking station and the combined 66 kV and 22 kV summer peak demand is forecast to decline by 0.9% per annum for the next few years. To accurately assess the transformer loading, the 66 kV and 22 kV loads need to be considered together because of the physical arrangement of the transformer windings.

The peak load on the station reached 92.8 MW (95 MVA) in summer 2013/14. The recorded peak demand in summer 2015/16 was 89.3 MW (91.3 MVA), which was lower than the 2013/14 station peak demand due to relatively mild weather conditions experienced in summer 2015/16 compared to summer 2013/14. The demand at WOTS 66 kV and 22 kV is expected to exceed 95% of the 50th percentile peak demand for 4 hours per annum. The station load has a power factor of 0.979 at maximum demand but load on the transformers has a power factor of 0.99 due to 22 kV capacitor banks installed at the station.

The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at an ambient temperature of 35°C. The combined 66 kV and 22 kV load at WOTS is not expected to reach the “N” summer station rating prior to 2025/26, but it presently exceeds the “N-1” rating at the 50th and 10th percentile summer demand level, and is forecast to continue to do so with a declining trend. Demand on the individual 66 kV and 22 kV windings is well within the ratings of the individual windings.
The combined 66 kV and 22 kV winter maximum demand at WOTS is less than the summer maximum demand and the station winter rating is higher than the summer rating. Forecast 50th and 10th percentile winter demand at WOTS 66 kV and 22 kV is not expected to exceed the “N -1” winter station rating in the next ten years.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile summer demand forecast, and the hours each year that the 50th percentile summer demand forecast is expected to exceed the “N-1” capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

![WOTS 66kV and 22kV combined Summer Peak Demand Forecasts](chart1.png)

![Annual Energy and Hours at Risk at WOTS (Single Contingency Only)](chart2.png)
Comments on Energy at Risk - Assuming HPS generation is not available

Assuming that Hume Power Station is unavailable, then for a major outage of any one of the two 330/66/22 kV transformers at WOTS over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50\textsuperscript{th} percentile temperature. However, due to the declining demand over the forecast period, the number of hours at risk is expected to reduce from 21 hours in 2016/17 to about 1 hour in summer 2025/26. The energy at risk under “N-1” condition is estimated to reduce from 56 MWh in 2016/17 to 1 MWh in summer 2025/26. The estimated value to consumers of the energy at risk in 2016/17 is approximately $2.3 million (based on a value of customer reliability of $40,605/MWh at WOTS)\textsuperscript{1}.

However the probability of a major outage of one of the two transformers occurring over the year is very low, at about 1.0\% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217\%. When the energy at risk (56 MWh for summer 2016/17) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 0.2 MWh. The corresponding value of expected unserved energy is approximately $9,800.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50\textsuperscript{th} percentile) summer temperatures occurring in each year. Under higher (10\textsuperscript{th} percentile) summer temperature conditions, the energy at risk in 2016/17 is estimated to be 625 MWh. The estimated value to consumers of the energy at risk in 2016/17 is approximately $25.4 million. The corresponding expected unserved energy at the 10\textsuperscript{th} percentile demand forecast is 2.7 MWh, which has an estimated value to consumers of approximately $0.11 million.

Given the forecast decline in demand over the 10 year planning period, by 2025/26 the energy at risk for the 10\textsuperscript{th} percentile demand forecast is 61 MWh, and the expected unsupplied energy is estimated to be around 0.3 MWh. The corresponding value of expected unserved energy is approximately $10,700.

The key statistics for the year 2016/17 under “N-1” outage conditions are summarised in the table below.

<table>
<thead>
<tr>
<th>MWh</th>
<th>Valued at consumer interruption cost</th>
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</thead>
<tbody>
<tr>
<td>Energy at risk at 50\textsuperscript{th} percentile demand forecast</td>
<td>56</td>
</tr>
<tr>
<td>Expected unserved energy at 50\textsuperscript{th} percentile demand</td>
<td>0.2</td>
</tr>
<tr>
<td>Energy at risk at 10\textsuperscript{th} percentile demand forecast</td>
<td>625</td>
</tr>
<tr>
<td>Expected unserved energy at 10\textsuperscript{th} percentile demand</td>
<td>2.7</td>
</tr>
</tbody>
</table>

If one of the 330/66/22 kV transformers at WOTS is taken off line during peak loading times and the “N-1” station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is enabled by AusNet Transmission Group’s TOC\textsuperscript{2} to

\textsuperscript{1} The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.

\textsuperscript{2} Transmission Operation Centre.
protect the connection assets from overloading\textsuperscript{3}, will act swiftly to reduce the loads in blocks to within safe loading limits. If OSSCA operation does occur, any load reductions that are in excess of the amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with AusNet Electricity Services’ operational procedures after the operation of the OSSCA scheme.

If OSSCA operates at WOTS, it would automatically shed about 60 MVA of load progressively, affecting up to approximately 13,000 customers.

**Comments on Energy at Risk - Assuming HPS generation is available**

The previous comments on energy at risk are based on the assumption that there is no embedded generation available to offset the 330/66/22 kV transformer loading.

However, the generation from Hume Power Station (HPS) can be fed into the WOTS 66 kV bus. The power station is capable of generating up to 58 MVA. This generation can also be connected to the TransGrid 132 kV Network in New South Wales. The generation from HPS is dependent on water releases from Hume Dam for irrigation and the water level in the dam can vary widely from year to year. There is presently no guarantee that generation from HPS will be available to offset transformer loading at WOTS. With HPS generating to its full capacity there would be no energy at risk at WOTS over the ten year planning horizon for the 50\textsuperscript{th} or 10\textsuperscript{th} percentile summer maximum demand forecasts.

**Feasible options for alleviation of constraints**

If the demand at WOTS continues to decline in accordance with the forecast, there will be no energy at risk after about 10 years. Therefore it is important to monitor the demand at WOTS and to take appropriate action to manage the risk at the lowest cost to consumers.

The following are potentially feasible options for addressing constraints at this station.

1. **Load transfers**

   Only 1 MVA of load can be shifted away from WOTS using the existing distribution network so this option has limited ability to manage the risk at WOTS in the near future.

2. **Addition of Power Factor Correction Capacitors**

   The station is currently running with a power factor of around 0.98 at summer peak. At this power factor the use of additional capacitor banks to reduce the MVA loading would only provide marginal benefits.

3. **Demand reduction**

   Over sixty percent of the peak demand is from Commercial and Industrial customers and AusNet Electricity Services will be looking into demand management through either special tariff incentives, or a demand management aggregator to assess these alternatives to network augmentation.

\textsuperscript{3} OSSCA is designed to protect connection transformers against damage caused by overloads. Damaged transformers can take months to repair or replace which can result in prolonged, long term risks to the reliability of customer supply.
4. **Embedded generation**

As discussed above, subject to available water HPS can provide up to 58 MVA of network support to WOTS.

5. **Fine tuning OSSCA**

OSSCA scheme settings are reviewed annually so as to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading.

It is noted that the two 330/66/22 kV transformers at WOTS are the only two of this voltage ratio in Victoria. AusNet Transmission Group does not have a spare transformer suitable for use at WOTS, so it is expected that it would take approximately 12 months to replace a failed transformer at WOTS.

The table on the following page provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy assuming embedded generation is not available.
WODONGA TERMINAL STATION 66kV and 22kV Loading (WOTS)

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: AusNet Electricity Services (100%)

Normal cyclic rating with all plant in service 162 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating 81 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating 87 MVA

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<tbody>
<tr>
<td>50th percentile Summer Maximum Demand (MVA)</td>
<td>89.3</td>
<td>88.3</td>
<td>87.3</td>
<td>85.8</td>
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<td>84.1</td>
<td>82.8</td>
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<tr>
<td>50th percentile Winter Maximum Demand (MVA)</td>
<td>73.6</td>
<td>72.8</td>
<td>72.6</td>
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<td>10th percentile Summer Maximum Demand (MVA)</td>
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<td>10th percentile Winter Maximum Demand (MVA)</td>
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<td>74.6</td>
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<td>73.8</td>
</tr>
<tr>
<td>N - 1 energy at risk at 50th percentile demand (MWh)</td>
<td>56</td>
<td>38</td>
<td>24</td>
<td>11</td>
<td>12</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>N - 1 hours at risk at 50th percentile demand (hours)</td>
<td>21</td>
<td>17</td>
<td>12</td>
<td>6</td>
<td>7</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>N - 1 energy at risk at 10th percentile demand (MWh)</td>
<td>625</td>
<td>496</td>
<td>379</td>
<td>253</td>
<td>215</td>
<td>157</td>
<td>129</td>
<td>110</td>
<td>76</td>
<td>61</td>
</tr>
<tr>
<td>N - 1 hours at risk at 10th percentile demand (hours)</td>
<td>116</td>
<td>102</td>
<td>88</td>
<td>70</td>
<td>51</td>
<td>44</td>
<td>41</td>
<td>33</td>
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<tr>
<td>Expected Unserved Energy at 50th percentile demand (MWh)</td>
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<td>0.2</td>
<td>0.1</td>
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<td>0.0</td>
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<tr>
<td>Expected Unserved Energy value at 50th percentile demand</td>
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<td></td>
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</tr>
<tr>
<td>Expected Unserved Energy value at 10th percentile demand</td>
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<tr>
<td>Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value</td>
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Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The summer rating is at an ambient temperature of 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. “Expected unserved energy” means “energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled Victorian Electricity Planning Approach, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)