2025
TRANSMISSION CONNECTION PLANNING REPORT

Produced jointly by the Victorian Electricity Distribution Businesses

2025 TRANSMISSION CONNECTION PLANNING REPORT
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EXECUTIVE SUMMARY

This document is a joint report on transmission connection planning in Victoria, prepared by the five Victorian electricity distribution businesses (**DBs**)[1], in accordance with the transmission connection planning requirements of Clause 19.3 of the Victorian Electricity Distribution Code of Practice[2] (**EDCoP)** and clause 5.13.2 of the National Electricity Rules (**the Rules**)[3].

Under the EDCoP, the DBs are responsible for planning the facilities that connect their distribution systems to the shared transmission network[4]. 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.

Apart from the connection assets at Deer Park terminal station, which are owned, operated and maintained by TransGrid, the transmission assets that provide DB connection services are located within terminal stations that are owned, operated, and maintained by AusNet Transmission Group.

The DBs apply a probabilistic planning approach to transmission connection assets, which is consistent with the approach[5] that has been applied by the Australian Energy Market Operator (**AEMO**) in planning the Victorian shared transmission network[6]. This approach involves estimating the expected cost to customers of loss of load if a transmission outage occurs, recognising that the probability of such an event is small. In addition to considering the potential loss of load, the DBs also consider the potential impacts of having to curtail embedded generation output to manage reverse power flows at a terminal station.

The probabilistic approach involves customers accepting the risk that there may be circumstances when the available terminal station capacity will be insufficient to meet customers' needs. Under this approach, a network or non-network option is regarded as credible if it can cost-effectively reduce the expected cost to customers. The preferred option is the credible option that maximises the net economic benefit compared with the status quo or 'do nothing' option.

This report examines whether there are emerging limitations at each terminal station and, if so, it describes the preferred network solution. In presenting this information, the report seeks non-network alternatives and indicates the maximum annual payment that may be available for non-network proponents.

This report does not present the detailed investment decision analysis that is required under the Regulatory Investment Test for Transmission (**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, and the likely investment requirements to address any emerging

1 The five DBs are: Jemena Electricity Networks (Vic) Ltd, CitiPower Pty Ltd, Powercor Australia Ltd, United Energy Distribution Pty Ltd, and AusNet Electricity Services Pty Ltd.

2 Version 2, effective from 1 May 2023.

3 Version 239, effective from 2 December 2025.

4 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.

5 Victorian-Electricity-Planning-Approach.pdf at AEMO | Victorian transmission network service provider role.

6 On 1 November 2025, responsibility for planning and directing the augmentation of the shared transmission network was transferred from AEMO to VicGrid.

constraints. Where relevant, the report also highlights the potential curtailment of embedded generation output. The RIT-T will be undertaken before any investment proceeds, and at that time, the evaluation will include consideration of the emission reduction benefits associated with options to address the transmission connection constraint.

Data centre development is likely to make a material contribution to demand growth over the next decade. However, there is some degree of uncertainty associated with the timing and location of demand increases driven by new data centre development. Given this uncertainty, for the purposes of this 2025 report, the following approach has been adopted:

- For terminal stations that supply Jemena's customers, Jemena has adopted forecasts that include an allowance for non-committed data centre loads.

- For other terminal stations, the demand forecasts include only committed data centre block loads.

While the forecasting approaches differ between terminal stations supplying Jemena's customers and the other DBs, the differing methodologies reflects the dynamic nature of the data centre load forecasts. The DBs will work together in advance of the 2026 Transmission Connection Planning Report to develop a common approach to forecasting new block loads, recognising that each DB is responsible for developing its own demand forecasts.

The table on the following pages summarises the analysis for each terminal station. Following the summary table is a map showing the approximate locations of the existing transmission to distribution connection terminal stations. The following points should be noted regarding the information presented in the summary table:

- For each terminal station, an indication of the potential exposure for customers relating to the impact of loss of load under the 'do nothing' option is provided, in accordance with DBs' obligations under clause 19.3 of the Victorian EDCoP. That information is provided in the form of expected unserved energy estimates which reflect weightings of 0.7 and 0.3 respectively applied to the 50th and 10th percentile demand forecasts.

- For those terminal stations where embedded generation output is at risk of curtailment, this risk is noted and the associated expected volume of export energy curtailed is shown. The expected costs of export curtailment are not quantified. Further detailed assessment of these costs will be undertaken as part of any future RIT-T.

- The demand forecasts used in preparing this report are set out in the 2025 Terminal Station Demand Forecasts, which are prepared by the DBs and published alongside this report.

- For each terminal station, the table identifies alternatives to network augmentation that may alleviate emerging constraints.

- The analysis presented in this report may be subject to change as new information, including demand forecasts and project costs, becomes available.

In accordance with their obligations under the Rules to undertake joint planning, the DBs provide VicGrid with the transmission connection point data for sites with limitations as specified in section 4.1 of the Australian Energy Regulator's (**AER's**) Transmission Annual Planning Report (**TAPR**) Guideline.

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

- Aaron O'Brien, Manager – Forecasting & Insights, CitiPower, Powercor & United Energy, phone 9683 4938.
- Ali Kharrazi, Manager – Sub-Transmission Network Planning, Network Management (D), AusNet Services, phone 1300 360 795.
- Theodora Karastergiou, Future Network & Planning Manager, Jemena, phone 9173 7383.

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.

Summary of risk assessment and options for alleviation of constraints

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[7] (in MWh, and valued at VCR)	Expected embedded generation output curtailed (in MWh)	Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
Altona – Brooklyn (ATS/BLTS)	By 2028	646 MWh in 2028 ($23.7 million)	Nil over the ten-year planning horizon	Install additional transformation capacity and reconfigure 66 kV exits at ATS or BLTS. As a temporary measure, the expected load at risk will be managed by load transfers to ATS West and DPTS. A RIT-T was commenced in September 2025, and a Project Assessment Draft Report should be published in the first quarter of 2026.	$2.7 million	Demand reduction; Local generation; Battery storage.
Altona no 3 & 4 (ATS West) 66kV	Not before 2025	13 MWh in 2025 ($ 0.54 million)	Nil over the ten-year planning horizon	Install additional transformation capacity and reconfigure 66 kV exits at ATS	$2.7 million	Demand reduction; Local generation; Battery storage.
Ballarat (BATS)	Not before 2035	27.6 MWh in 2035 ($1.12 million)	4.8 MWh in 2035 (Immaterial value)	Install a third 150 MVA 220/66 kV transformer.	$2.7 million	Demand reduction; Local generation; Battery storage.
Bendigo 22 kV (BETS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Bendigo 66 kV (BETS 66 kV)	Not before 2035	0.94 MWh in 2035 ($40,000)	0.7 MWh in 2035 (Immaterial value)	Install an additional 150 MVA 220/66 kV transformer.	$2.7 million	Demand reduction; Local generation; Battery storage.
Brooklyn 22 kV (BLTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Brunswick 22 kV (BTS 22 kV)	No demand-driven augmentation of import capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Brunswick 66 kV (BTS 66 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					

[7] Weightings of 0.7 and 0.3 respectively are applied to the 50th and 10th percentile demand forecasts.

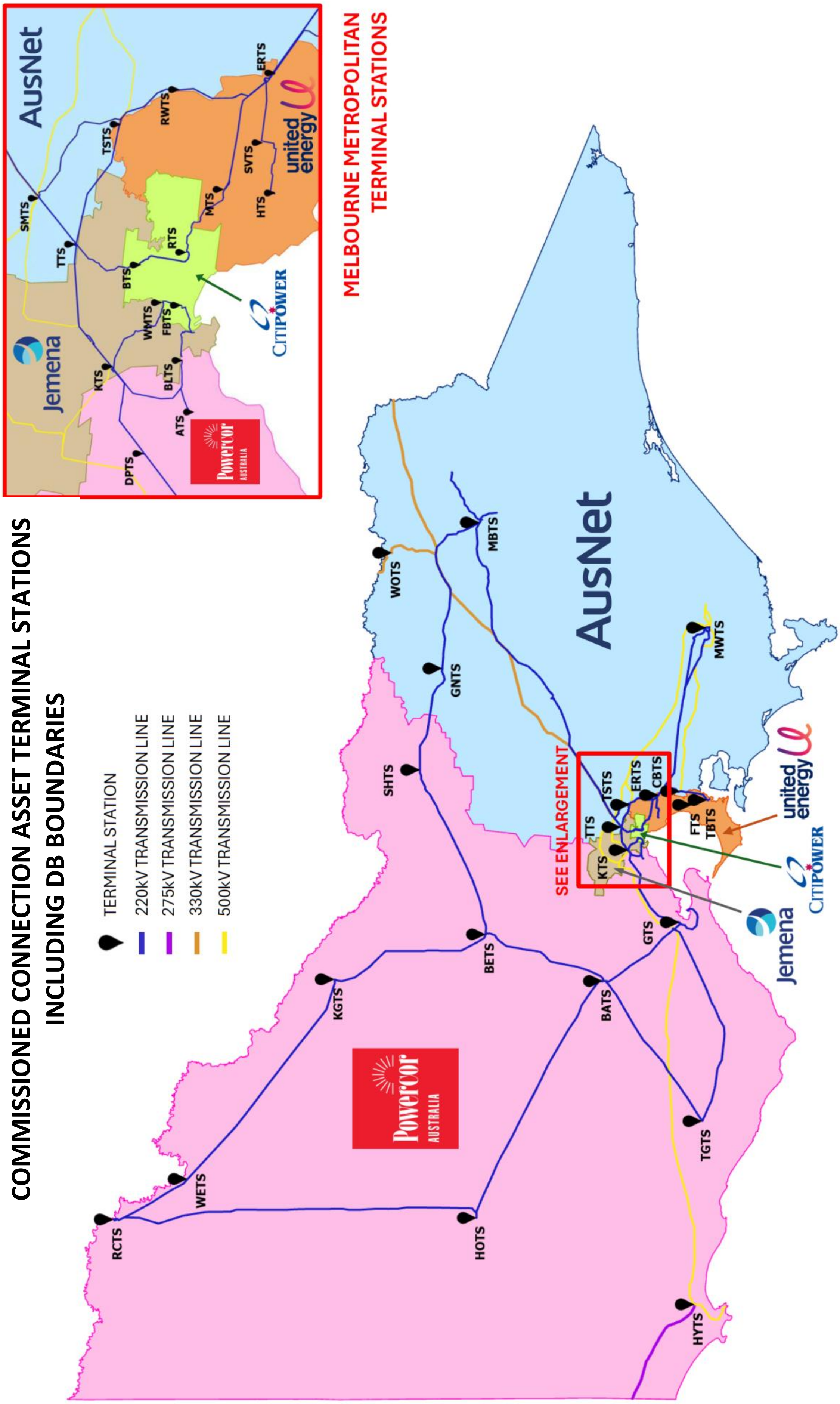
Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[7] (in MWh, and valued at VCR)	Expected embedded generation output curtailed (in MWh)	Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
Cranbourne 66 kV (CBTS 66 kV)	Before the 2026/27 summer	1.6 MWh in 2026/27 ($0.07 million)	Nil over the ten-year planning horizon	Install a fourth transformer. For summer 2025/26, the hot spare transformer at the station will be temporarily connected as a fourth transformer to supplement capacity when necessary.	$3.5 million	Demand reduction; Local generation Battery storage.
Deer Park (DPTS)	Not before 2035	41.3 MWh in 2035 ($1.6 million)	Nil over the ten-year planning horizon	Install an additional 225 MVA transformer.	$2.7 million	Demand reduction; Local generation; Battery storage.
East Rowville (ERTS)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Fishermans Bend (FBTS)	Not before 2035	0.3 MWh in 2035 ($11,000)	Nil over the ten-year planning horizon	Install a fourth transformer	$2.7 million	Demand reduction; Local generation; Battery storage
Frankston (FTS)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Geelong (GTS)	Not before 2035	2.3 MWh in 2035 ($92,000)	Nil over the ten-year planning horizon	Install a fifth transformer and reconfigure 66 kV exits at GTS.	$2.7 million	Demand reduction; Local generation: Battery storage
Glenrowan (GNTS)	No demand-driven augmentation of import capacity is expected to be required within the ten-year planning horizon. Forecast minimum demand exceeds the N-1 export rating at GNTS. In the event of a transformer outage at GNTS, embedded generators may need to reduce generation to avoid overloading the remaining transformer. By 2035 there is projected to 115 MVA of embedded generation at risk of being constrained off. This equates to an expected volume of export energy curtailed of 575 MWh in 2035. The cost of any augmentation of export capacity would either be met by the connecting generator(s), or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.					
Heatherton (HTS)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Horsham (HOTS)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[7] (in MWh, and valued at VCR)	Expected embedded generation output curtailed (in MWh)	Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
Heywood (HYTS 22 kV)	A 22 kV point of supply was established in late 2009, by utilising the tertiary 22 kV on 2 of the existing 3 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 import capacity at the station to supply all expected 22 kV load over the forecast period, even with one transformer out of service. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Keilor (KTS)	By 2029	857 MWh at B(1,2,5) in 2030 ($25.5 million) and 577 MWh at B(3,4) in 2029 ($33.5 million)	Nil over the ten-year planning horizon	Upgrade all three transformers at KTS (B1,2,5), install additional transformation capacity at KTS B(3,4) and transfer 66 kV exits from KTS B(1,2,5) to KTS B(3,4) group. A RIT-T assessment has been commenced, and a Project Assessment Draft Report (PADR) is expected to be published during the first quarter of 2026.	$7.1 million	Demand reduction; Local generation; Battery storage
Kerang (KGTS)	Demand-driven augmentation of import capacity is not expected to be economically justified within the ten-year planning horizon. From 2026, at the 50th and 10th percentile minimum demand forecast, there is expected to be insufficient capability to enable all embedded generation to be exported, even with all transformers in service. For an outage of one transformer in 2035, 53 MVA of generation is at risk of curtailment (equating to an expected volume of generation curtailment of 359 MWh). In these circumstances, the cost of any augmentation to increase export capacity would either be met by the connecting generator(s) or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.					
Malvern 22 kV (MTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Malvern 66 kV (MTS 66 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Mount Beauty (MBTS)	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 up to 48 hours, as the “hot spare” transformer at the station is brought into service. At a cost of approximately $16 million, it would not be economic to install full switching of the hot spare transformer at MBTS during the 10 year planning horizon to eliminate this risk. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Mount Cottrell 132 kV (MCTS)	Mount Cottrell Terminal Station (MCTS) 132 kV is a proposed new terminal station and is expected to be commissioned in 2027. It will consist of two 350 MVA 220/132 kV transformers and will be the main source of supply for customers in the Mount Cottrell area. Powercor expects to shortly publish a RIT-T Project Specification Consultation Report in relation to the proposed MCTS.					

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[7] (in MWh, and valued at VCR)	Expected embedded generation output curtailed (in MWh)	Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
Morwell (MWTS)	2031	89.9 MWh in 2031 ($3.48 million)	Nil over the ten-year planning horizon	Install a fourth transformer at MWTS.	An estimate of the annualised cost of installing a fourth transformer at MWTS has not yet been completed, but it is likely to exceed the expected value of unserved energy in 2031.	Demand reduction; Local generation; Battery storage
Red Cliffs 22 kV (RCTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Red Cliffs 66 kV (RCTS 66 kV)	Not before 2035	Nil over the forecast period.	518 MWh in 2035 (unlikely to be of sufficient value to economically justify any transmission connection augmentation)	Demand-driven augmentation is unlikely to be required over the ten-year planning horizon. Connection of additional embedded generation may lead to an increased risk of terminal station transformers overloading due to reverse power flows. The cost of any augmentation of export capacity would either be met by the connecting generator(s), or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.	N/A	Demand reduction; Local generation; Battery storage
Richmond 22 kV (RTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Richmond 66 kV (RTS 66 kV)	The 50th percentile maximum demand at RTS 66 kV remains below its N-1 import rating over the ten-year planning period. The load at risk during the 10th percentile temperature maximum demand conditions will be managed through load transfers within the sub-transmission network. Therefore, no demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Ringwood 22 kV (RWTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					

<table>
<tr><th>Terminal Station</th><th>Indicative timing for preferred network solution (using VCR)</th><th>Expected unserved energy[7] (in MWh, and valued at VCR)</th><th>Expected embedded generation output curtailed (in MWh)</th><th>Preferred network solution</th><th>Indicative annual cost of preferred network solution</th><th>Potentially feasible non-network solutions</th></tr>
<tr><td>Ringwood 66 kV (RWTS 66 kV)</td><td colspan="6">At the 10th percentile temperature, for an outage of one 220/66 kV transformer at RWTS, there will be a minor amount of load at risk from 2033. This risk will be monitored over the coming years to determine when action needs to be taken.
There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.</td></tr>
<tr><td>Shepparton (SHTS)</td><td colspan="6">No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon.
With all transformers in service there is expected to be sufficient station export capability to accommodate all forecast embedded generation output over the ten-year planning horizon. By 2035, approximately 105 MVA of embedded generation is at risk of curtailment for the loss of one transformer. This equates to 1,581 MWh of energy at risk of curtailment, corresponding to an expected volume of curtailed energy of approximately 10.5 MWh, which is immaterial from a transmission connection planning perspective. The cost of any augmentation of export capacity would either be met by the connecting generator(s) or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.</td></tr>
<tr><td>South Morang (SMTS)</td><td colspan="6">Assuming no output from the 150 MW Somerton Power Station (which is connected to the 66 kV bus at SMTS), there is 412 MWh of expected unserved energy (worth $16.8 million) at SMTS at the 10th percentile demand forecast in 2026. While there is no firm commitment that generation will be available to offset transformer loading at SMTS, it is most likely that the times of maximum demand at SMTS will coincide with periods of high wholesale electricity prices, resulting in a high likelihood that the power station will be generating.
AusNet Services and Jemena commenced a RIT-T by publishing a Project Specification Consultation Report in June 2025 to identify feasible solutions to address the energy at risk at SMTS. The next report of the RIT-T, the Project Assessment Draft Report is expected to be published during the first quarter of 2026.</td></tr>
<tr><td>Springvale (SVTS)</td><td colspan="6">No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon.
There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.</td></tr>
<tr><td>Templestowe (TSTS)</td><td>Not before 2035</td><td>0.5 MWh in 2035 ($21,000)</td><td>Nil over the ten-year planning horizon</td><td>Install a fourth 150 MVA 220/66 kV transformer at TSTS.</td><td>$3.5 million</td><td>Demand reduction;
Local generation</td></tr>
<tr><td>Terang (TGTS)</td><td>Not before 2035</td><td>16.7 MWh in 2035 ($0.6 million)</td><td>4 MWh in 2034 (Immaterial value)</td><td>Install a third 220/66 kV transformer (150 MVA) at TGTS. Connection of additional generation may lead to an increased risk of terminal station transformers overloading due to reverse power flows. The cost of any augmentation of export capacity would either be met by the connecting generator(s) or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.</td><td>$2.7 million</td><td>Demand reduction;
Local generation;
Battery storage.</td></tr>
</table>

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[7] (in MWh, and valued at VCR)	Expected embedded generation output curtailed (in MWh)	Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
Thomastown (TTS)	Not before 2032	59.6 MWh in 2032 ($2.37 million)	Nil over the ten-year planning horizon	Install two new 220/66 kV transformers (150 MVA each).	$2.7 million per transformer	Demand reduction; Local generation; Battery storage.
Tyabb (TBTS)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Wemen (WETS)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. Forecast 10th percentile minimum demand in 2026 is 13.5 MVA lower than the (N) export rating. If actual minimum demand falls below the (N) export rating, or in the event of a transformer outage at WETS, the generators may have to reduce generation to avoid overloading the remaining transformer. However, minimum demand is forecast to increase over the planning period, so the volume of expected constrained-off generation is expected to decrease from 2026. By 2035 there is projected to be 73.5 MVA of embedded generation at risk of being constrained off. This equates to an expected volume of export energy curtailed of 228 MWh in 2035. The cost of any augmentation of export capacity would either be met by the connecting generator(s), or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.					
West Melb 22 kV (WMTS 22 kV)	Under joint plans developed by CitiPower and AusNet Transmission Group, existing load supplied from WMTS 22 kV will be transferred to adjacent stations to enable the retirement of all of the existing WMTS 22 kV systems in the near future. No augmentation of capacity is expected to be required over the remaining life of the station. There is expected to be sufficient station export capability to accommodate all embedded generation output until the station is de-commissioned.					
West Melb 66 kV (WMTS 66 kV)	No demand-driven augmentation of capacity is expected to be required within the ten-year planning horizon. There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.					
Wodonga (WOTS)	Not before 2034/35	50 MWh in 2034 ($1.9 million) excluding generation from Hume PS or any other source	Nil	Installation of the WOTS spare transformer (330/66/22 kV 75 MVA)	$2 million	Demand management Local generation; Battery storage.


COMMISSIONED CONNECTION ASSET TERMINAL STATIONS
INCLUDING DB BOUNDARIES
TERMINAL STATION
220kV TRANSMISSION LINE
275kV TRANSMISSION LINE
330kV TRANSMISSION LINE
500kV TRANSMISSION LINE
MELBOURNE METROPOLITAN
TERMINAL STATIONS
SEE ENLARGEMENT
AusNet
Jemena
CitiPower
united energy
Powercor AUSTRALIA
RCTS
WETS
HOTS
KGTS
BETS
BATS
SHTS
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BLTS
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DPTS

1 INTRODUCTION AND BACKGROUND

1.1 Purpose of this report

This is a joint report on transmission connection planning in Victoria, prepared by the DBs in accordance with the requirements of clause 19.3 of the Victorian EDCoP and clause 5.13.2 of the Rules.

This report provides a high-level indication of the expected balance between capacity and demand at each terminal station[8] over the ten-year forecast period, and the intervention actions that may be required to address an emerging major constraint. Where applicable, this report also identifies the potential risk of curtailing embedded generation to manage reverse power flows at particular terminal stations.

Accordingly, this report provides a means of identifying those terminal stations where further consultation and detailed analysis (in accordance with the RIT-T) may be required. This report also provides preliminary information on potential opportunities to prospective proponents of non-network solutions at each of those terminal stations. Providing this information to the market should facilitate the efficient development of network and non-network solutions to best meet the needs of customers.

1.2 Victorian joint planning arrangements for transmission connection assets

In Victoria:

- as explained in further detail in section 1.3.1 below, the DBs are responsible for planning the augmentation of the facilities that connect their distribution systems to the shared transmission network[9]; and
- On 1 November 2025, responsibility for planning and directing the augmentation of the shared transmission network was transferred from AEMO to VicGrid.

Under Chapter 6A of the Rules, transmission connection assets that provide exit services to distributors are classified as prescribed transmission services.

Figure 1 below illustrates the distinction between the shared transmission network and transmission connection assets in a notional network. The delineation between shared network and connection assets depends on high voltage switching configurations and other factors that may vary from one transmission connection point to another. Nonetheless, Figure 1 provides a useful illustration of the distinction between shared network and connection assets.

8 A terminal station is a facility that connects a distribution network to the shared transmission network.

9 The shared transmission network (referred to as the "declared shared network" in section 50C of the National Electricity Law) is the main extra high voltage network that provides or potentially provides supply to more than a single point. That network includes all lines rated above 66 kV and main system tie transformers that operate at two or three voltage levels above 66 kV.

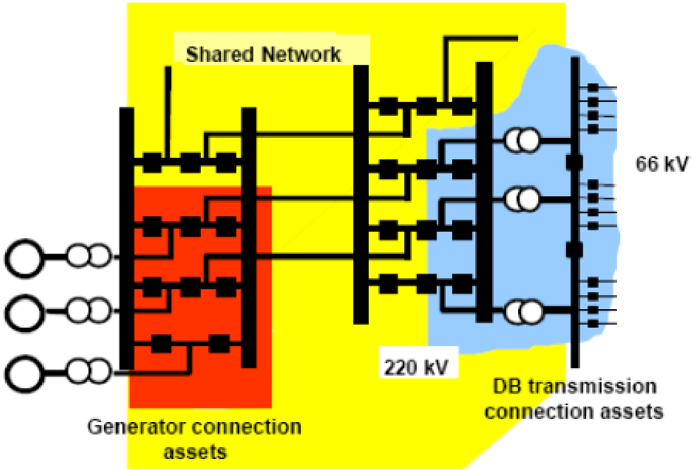

Figure 1: Shared network and connection assets in a notional network

Except for the connection assets at Deer Park Terminal Station (**DPTS**), the transmission assets that provide DB connection services are located within terminal stations that are owned, operated, and maintained by AusNet Transmission Group[10]. Connection services are provided by the owners of the transmission connection assets in accordance with their connection agreements with the relevant DBs. Those agreements set out, among other things, the standard of connection services to be provided.

In Victoria, the framework under which connections to the transmission network occur differs from other NEM regions. Specifically, section 50C of the National Electricity Law (**NEL**)[11] authorises VicGrid "*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, VicGrid (and its predecessor AEMO) and the DBs undertake joint planning to ensure the shared transmission and distribution networks and transmission connection facilities are developed efficiently. Under the joint planning arrangements, the parties have agreed that subject to the thresholds set out in the Rules, joint planning projects should be assessed by applying the RIT-T. Joint planning projects include those 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.

The DBs also liaise regularly with AusNet Transmission Group to coordinate their transmission connection augmentation plans with AusNet Transmission Group's asset renewal and replacement plans.

10 The connection assets at Deer Park Terminal Station were commissioned in September 2017, and are owned, operated and maintained by TransGrid.

11 As amended by section 16ZP of the National Electricity (Victoria) Act 2005, amendments as at 1 November 2025.

1.3 DBs' obligations as transmission connection planners

1.3.1 Victorian regulatory instruments

Clause 19.2.1(b) of the Victorian EDCoP requires the DBs to use best endeavours to develop and implement plans for the establishment and augmentation of transmission connections in a way that minimises costs to customers taking into account distribution losses.

Clause 19.3 of the Victorian EDCoP states:

> "19.3.1 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.
>
> 19.3.2 For the purpose of clause 19.3.1, the report must include the following information:
>
> (a) the historical and forecast demand from, and capacity of, each transmission connection;
>
> (b) an assessment of the magnitude, probability and impact of loss of load for each transmission connection;
>
> (c) each distributor's planning standards;
>
> (d) 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;
>
> (e) 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
>
> (f) 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.
>
> 19.3.3 Each distributor must publish the Transmission Connection Planning Report on its website and, on request by a customer, provide the customer with a copy."

Clause 19.5 of the Victorian EDCoP relates to the security of supply of the Melbourne CBD. That provision establishes a separate planning process that applies to the network supplying the Melbourne CBD only. CitiPower's CBD plans are provided in its distribution annual planning report.

1.3.2 National Electricity Rules

Part D of Chapter 5 of the Rules[12] sets out provisions governing the planning and development of networks. Those provisions require, among other things, Transmission and Distribution Network Service Providers to:

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12 Version 239 of the Rules was in force at the time of preparing this report.

- 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 any projected network limitations; and
- undertake analysis of proposed network investments using the Regulatory Investment Test for Distribution (**RIT-D**) or the RIT-T, as appropriate.

As noted in section 1.2, joint planning projects involving transmission connection and distribution investment are assessed by applying the RIT-T.

Clause 5.13.2 of the Rules requires Distribution Network Service Providers (**DNSPs**) 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 elsewhere in accordance with jurisdictional electricity legislation[13]. Pursuant to clause 5.13.2(d) of the Rules, this report presents the following information on transmission-distribution connection planning required under schedule 5.8. The table below lists the relevant clauses of schedule 5.8 and provides a cross-reference to the section of this report where the required information is presented.

Table 1: Schedule 5.8 requirements relating to transmission-distribution connection points addressed in this report

Schedule 5.8 clause	Matters addressed	Where the information is presented in this report
S5.8(b)(1)	A description of the forecasting methodology used.	Chapters 3 and 4.
S5.8(b)(2)(i), (iv), (v), (vi), (vii), (viii), and (ix); S5.8(b)(2A)(i), (iv), (v), (vi), and (vii)	Load forecasts and forecasts of import capacity; forecast use of distribution services by embedded generating units, and export capacity.	Individual risk assessments for each terminal station.
S5.8(b)(3)	Forecasts of future transmission-distribution connection points and any associated connection assets.	The Executive Summary and individual risk assessments for each terminal station.
S5.8(c)	The impact of system limitations on the capacity at transmission-distribution connection points.	Individual risk assessments for each terminal station.
S5.8(h)	The results of joint planning undertaken with Transmission Network Service Providers.	Section 1.2 describes the joint planning arrangements. The Executive Summary and individual risk assessments for each terminal station present the results of joint planning.

13 Clause 5.13.2(d) of the Rules states: “a Distribution Network Service Provider is not required to include in its Distribution Annual Planning Report information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation.”

Schedule 5.8 clause	Matters addressed	Where the information is presented in this report
S5.8(i)(1)	The results of joint planning undertaken with other Distribution Network Service Providers.	As above.
S5.8(n)	A map showing transmission-distribution connection points.	The Executive Summary.

1.3.3 Service Target Performance Incentive Scheme for Distribution Businesses

Version 2.0 of the Service Target Performance Incentive Scheme (**STPIS**)[14] applies to the DBs. The STPIS provides a revenue bonus when service performance is better than the target, and a penalty when service performance is worse than the target.

The operation of the STPIS 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, 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 distributor is responsible for transmission connection planning.

The financial incentives under these arrangements reinforce the DBs' responsibilities regarding transmission connection planning, which are set out in the Victorian EDCoP as explained in section 1.3.1 above.

1.3.4 Connection arrangements for embedded generators who are registered participants

An embedded generating unit connecting to a distribution network, where the Connection Applicant is a Registered Participant or a person intending to become a Registered Participant, is subject to the connection arrangements set out in Rules 5.3 and 5.3A. Under those arrangements the connecting party is required to pay the costs of providing the connection services which may, in principle, include augmenting transmission connection assets.

At some terminal stations, power flows from new generation connections may lead to an increased risk of terminal station transformers overloading. In these circumstances, a connecting generator may determine that it is uneconomic for augmentation of terminal station capacity to be undertaken, in which case, the need for and suitability of a generation runback scheme would be investigated by the DB. These schemes are designed to reduce the amount of generation inflows, to ensure that distribution and transmission plant loadings are maintained within safe limits and the connection services provided to load customers are not adversely affected by the connection of additional embedded generation.

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

One purpose of this document is to provide information to proponents of non-network solutions (such as embedded generation, storage or demand-side management) regarding

[14] AER, *Electricity Distribution Network Service Providers - Service Target Performance Incentive Scheme*, Version 2.0, November 2018.

emerging network constraints. As explained in further detail in Chapter 3 below, the DBs aim to develop their networks and the associated transmission connection assets in a manner that maximises net economic benefit. To this end, proponents of non-network solutions to the emerging 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 for the DB to fully assess feasible network and non-network potential solutions, having regard to the lead times associated with evaluating, planning and implementing 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. That 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 and MVAr 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;

(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.

1.5 Implementing Transmission Connection Projects

In the absence of any commitment by interested parties to offer non-network solutions such as embedded generation, storage or demand-side management, the process of implementing 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. A detailed consideration of land acquisition issues and processes is beyond the scope of this report.

A limited number of vacant sites, currently owned by AusNet Transmission Group, have been reserved for possible future terminal station development in Victoria. Access to such land for transmission connection developments would need to be agreed upon with AusNet Transmission Group.

Granting a town planning permit on lands reserved for future terminal station development is not certain. In some municipalities, town planning approval may also be required for network augmentation on existing developed sites.

1.5.2 Connection Application

Where a network solution requires the establishment of new connection points with the shared transmission network, a connection agreement with VicGrid is required in accordance with clause 5.3 (Establishing or Modifying Connection) of the Rules. As explained in section 1.2, from 1 November 2025, the assets that form part of the Victorian declared shared transmission network fall under the planning jurisdiction of VicGrid. Hence, issues associated with 220 kV switching arrangements and connection to the shared transmission network, including direct connection to a 66 kV terminal station bus, would be clarified with VicGrid at the connection application stage.

VicGrid's requirements regarding new connections must be finalised through a joint planning process involving VicGrid and the relevant DB(s). These activities can increase the lead time for delivering projects by some months.

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

A more detailed overview of the Victorian transmission connections process is available from VicGrid's website at: https://www.vicgrid.com.au/industry/access-and-connections/transmission-connections-process.

1.5.3 Connection Application to AusNet Transmission Group

It is most likely that establishing new transmission connections or augmenting existing transmission connections will require an interface to transmission assets owned by AusNet Transmission Group. In such cases, an initial "Connection Inquiry" outlining the broad scope of the 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 VicGrid and the relevant DB(s).

1.5.4 Town Planning Permit

For greenfield sites, DBs may need to engage the services of town planning consultants, because 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 VicGrid on the same site, it may become necessary to invite VicGrid 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 Social licence

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 to obtain a social licence. 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 explain the need for the project and its 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 EDCoP to augment transmission connections in a way that minimises costs to customers. 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.

1.5.7 Project lead times

The lead-time required to implement connection asset augmentation projects is typically between three and five years, depending on the particular circumstances. The critical path activities in the delivery of such projects include the following:

- Finalising any requirements for shared network augmentation associated with planned connection augmentation works. These requirements are assessed through the joint planning process, which involves VicGrid, AusNet Transmission Group and the DBs.

- Procuring a planning permit relating to the proposed works. 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 VicGrid, AusNet Transmission Group and the DBs through the joint planning process in Victoria.

- After completing the above two tasks successfully, the next tasks are:

    - finalising the scope of work;

    - preparing cost estimates (including an invitation to tender if the project is contestable); and

    - finalising and executing 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 task is delivering the project itself, including installing and commissioning the assets into service.

AusNet Transmission Group's recent experience indicates that the lead-time required for delivering transmission connection asset augmentation involving power transformers is between 18 and 24 months. In some cases, issues identified during the testing of completed transformer units may further extend the overall process.

Given 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

Figure 2 below provides a summary of the transmission connection planning and augmentation process under the regulatory framework that applies to the Victorian DBs.

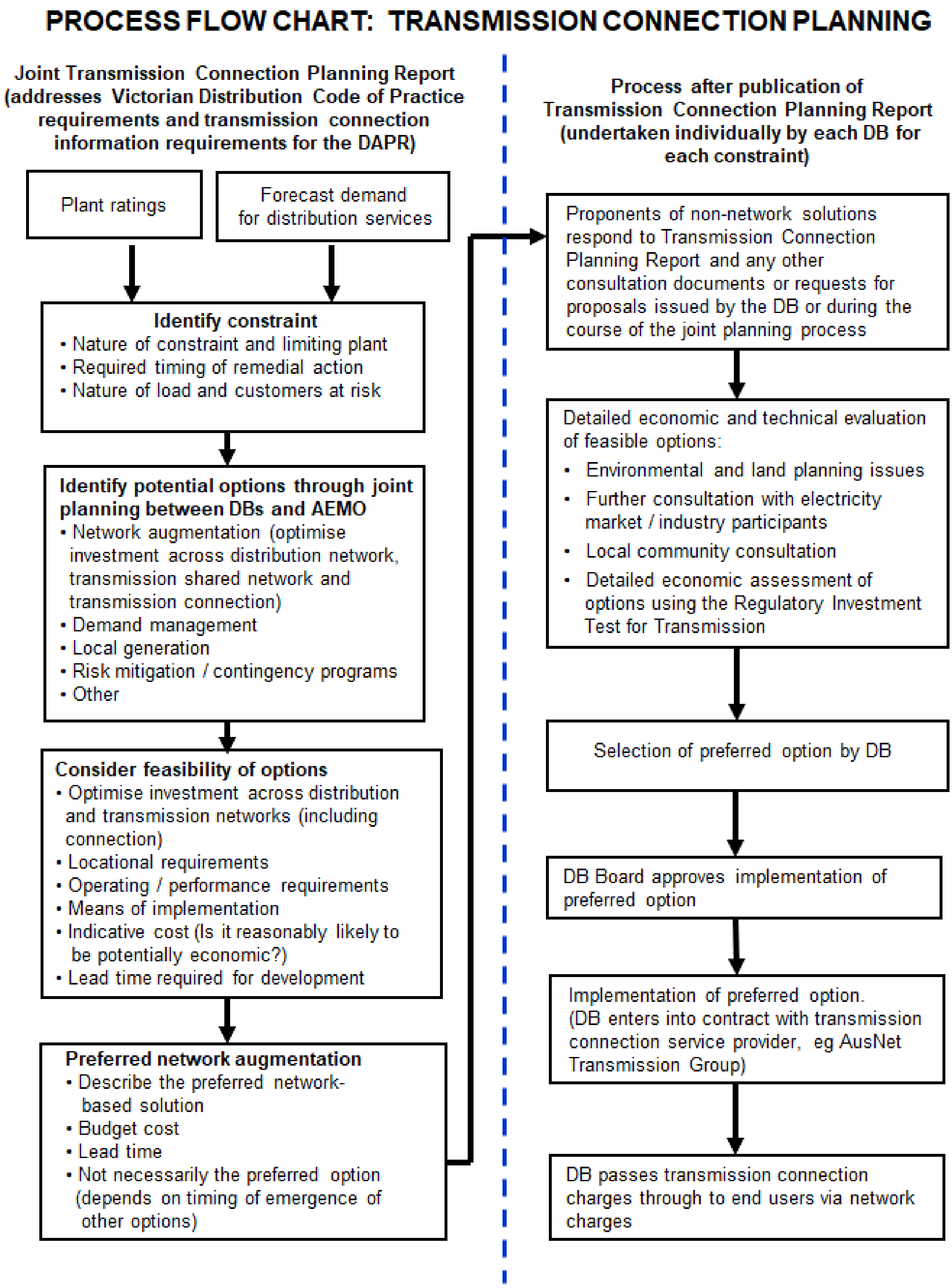

Figure 2: Process Flowchart – Transmission Connection Planning

2 Context for this planning report

2.1 Introduction

Significant change in the Victorian energy landscape continues to be driven by strong investment in large-scale and distributed renewable generation and storage across the state. In April 2025, the Victorian Minister for Energy and Resources stated[15]:

> "Victoria is experiencing a once-in-a-generation shift in how we get our electricity. As our ageing coal-fired power stations retire, they are being replaced by cheaper, more reliable renewable energy like wind and solar. At the same time, we are moving towards electricity as our primary energy source."

In its October 2025 Victorian Annual Planning Report (**VAPR**), AEMO Victorian Planning (**AVP**) noted:

- The geographic location of supply continues to diversify. Historically, much of Victoria's electricity was produced by large brown coal generators in the Latrobe Valley. Now, and increasingly in future, supply comes from renewable resources and interconnectors throughout Victoria.
- The latest forecasts show growth in electricity maximum demand for the next five years, driven by homes and businesses switching from gas to electricity, and electrification of transport. Further growth is expected in the maximum demand over the 5 to 10 year forecast period, driven by the connection of data centres.
- Minimum demand from the grid continues to decline, but more slowly than previously forecast. As consumers' distributed photovoltaic (**PV**) investments keep growing and meeting more of their energy needs, their grid demand falls, but this decline is forecast to be offset by increased electrification and data centre loads.

To help manage the transition to net-zero emissions by 2045, the Victorian government recently established a new organisation, VicGrid, to implement a statewide approach to planning Renewable Energy Zones and associated transmission investment. On 1 November 2025, responsibility for planning and directing the augmentation of the Victorian shared transmission network was transferred from AEMO to VicGrid.

These developments provide important context for this transmission connection planning report. The remainder of this chapter highlights recent policy and market developments, drawing on the information presented in AVP's October 2025 VAPR and other sources.

2.2 Changes in electricity consumption

Decarbonisation and increasing electrification are driving considerable changes in electricity usage. Significant growth in electricity consumption is expected from increased uptake of electric vehicles, the substitution of residential gas[16], the installation of battery storage, and the projected growth in data centres.

Data centres in particular are a rapidly growing sector, driven by the emergence of artificial intelligence, cloud computing, big data analytics and other technologies. Data centres are

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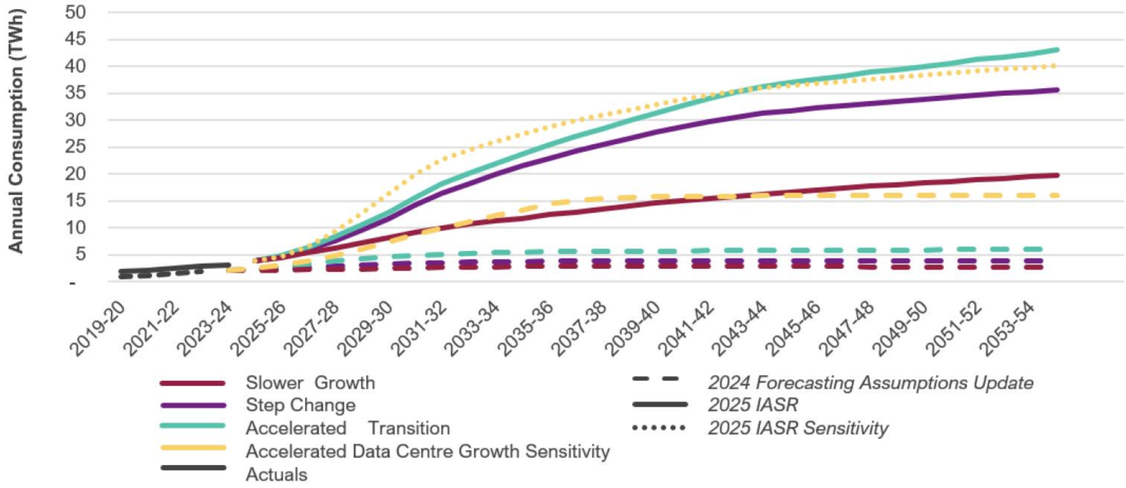
15 https://www.energy.vic.gov.au/renewable-energy/victorias-electricity-future.

16 Victorian Department of Energy, Environment and Climate Action, Gas Substitution Roadmap Update

energy-intensive operations. In FY 2025, AEMO estimated that data centres consumed around 4 TWh of electricity in the NEM (about 2–3% of total demand), with rapid growth expected under all scenarios.

In August 2025, AEMO announced the development of a new data centre forecasting methodology[17]. AEMO's data centre forecasts are set out in Figure 48 of its 2025 Inputs, Assumptions and Scenarios Report, which is reproduced below.



Note: Several sites were identified as data centres for the 2025 forecasts, lifting the historical data compared to the 2024 forecasts. *Slower Growth* and *Accelerated Transition* in the *2025 IASR* are compared with *Progressive Change* and *Green Energy Exports* respectively in the *2024 Forecasting Assumptions Update*.

Figure 3: AEMO's NEM data centre electricity consumption forecasts, all scenarios

It is noteworthy that AEMO's data centre demand forecasts are characterised by a high level of uncertainty. Section 4.2.5 of the October 2025 VAPR[18] presents the results of scenario analysis of new large load connections to the transmission network. In that report, AVP made the following observations:

> "Throughout 2024-25, AVP received over 18 GW of large [transmission-connected] load connection enquiries. The majority of those enquiries related to data centres in the western and northern metropolitan Melbourne areas, with a small amount of interest in south-eastern metropolitan Melbourne. The 2025 ESOO forecast approximately 1 GW of additional data centre load in Victoria by 2035. AVP does not anticipate that all the connection enquiry interest will eventuate within the 10-year planning horizon. If all the large load connections did intend to proceed within the planning horizon, the maximum demand for Victoria would more than double and it would not be possible to build the required generation and transmission infrastructure to reliably support the additional demand."

At the distribution network level, the DBs are also receiving significant numbers of connection queries from data centre developers, and there is no certainty as to which connection enquiries will proceed. The timing of augmentation of transmission connection capacity indicated in this report may change depending on the need to supply new distribution-connected data centres and their load uptake.

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17 AEMO | AEMO's updated forecasting methodology targets rapidly growing electricity loads, following industry consultation.

18 AEMO Victorian Planning, Victorian Annual Planning Report, October 2025, page 80. Copy available from: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

The DBs' approach to assessing the uncertainty of data centre load forecasts for the purpose of transmission connection planning is described in section 4.3.

2.3 Government policy announcements and emission reduction targets

In August 2024, the Victorian Government published *Cheaper, Cleaner, Renewable: Our Plan for Victoria's Electricity Future.*[19] That document, which was updated in April 2025[20] forecasts that by 2035 Victoria's electricity system will be very different:

- Electricity use will have increased 50% or more through electrification of gas use and transport.
- Around 4.8 GW of coal-fired power generation will have closed.
- Around 11.4 GW of new grid-scale renewables will be installed, including 4 GW of offshore wind.
- There will be around 7.6 GW of additional rooftop solar generating capacity.
- There will be at least 6.3 GW of short and long duration storage.
- The VNI West and Marinus Link interconnectors will be online, exporting Victorian renewables and providing access to firming resources in the NEM.

In its August 2024 announcement, the Victorian government affirmed its commitment to its renewable energy targets of:

- 65% by 2030 and 95% by 2035;
- energy storage capacity targets of at least 2.6 GW by 2030 and at least 6.3 GW by 2035; and
- offshore wind energy generating capacity targets of at least 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040.

At the same time, the Victorian government reiterated its commitment to:

- reduce Victoria's greenhouse gas emissions by 45-50% below 2005 levels by 2030;
- reduce emissions by 75-80% by 2035; and
- achieve net-zero emissions by 2045.

One of the actions taken by the Victorian government to achieve its renewable energy targets has been to introduce a statewide approach to planning Renewable Energy Zones and transmission, led by the newly established organisation, VicGrid. As noted in further detail below, VicGrid published its first Victorian Transmission Plan in August 2025.

19 Our plan for Victoria's electricity future (energy.vic.gov.au)

20 https://www.energy.vic.gov.au/renewable-energy/victorias-electricity-future

2.4 VicGrid's 2025 Victorian Transmission Plan

VicGrid was established in 2024 to coordinate the overarching planning and development of Victorian Renewable Energy Zones. On 1 November 2025, VicGrid's functions were expanded to include planning the Victorian shared transmission network.

In August of this year, VicGrid published the 2025 Victorian Transmission Plan, which outlines a strategic approach to transitioning Victoria's energy infrastructure towards renewable sources.

The plan identifies 6 proposed renewable energy zones: Central Highlands, Central North, Gippsland, North West, South West and Western. The plan also proposes the establishment of a Gippsland Shoreline Renewable Energy Zone, which is a limited area where offshore wind farm developers will locate their connection infrastructure. The proposed zones are shown in Figure 4 below.

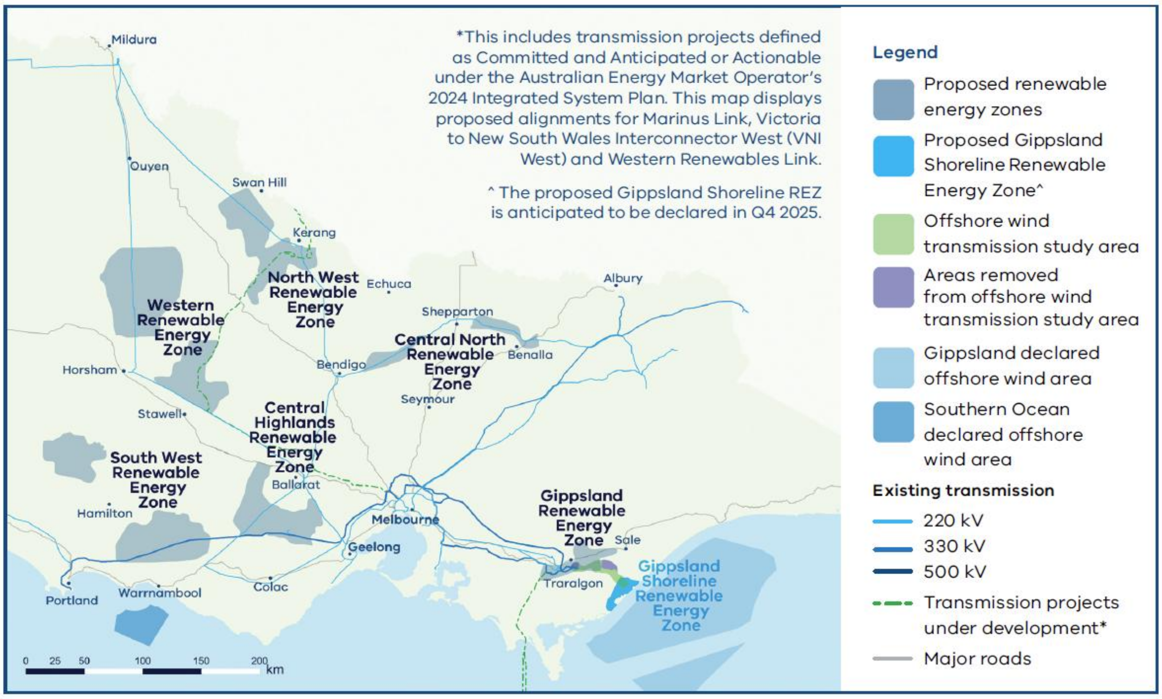
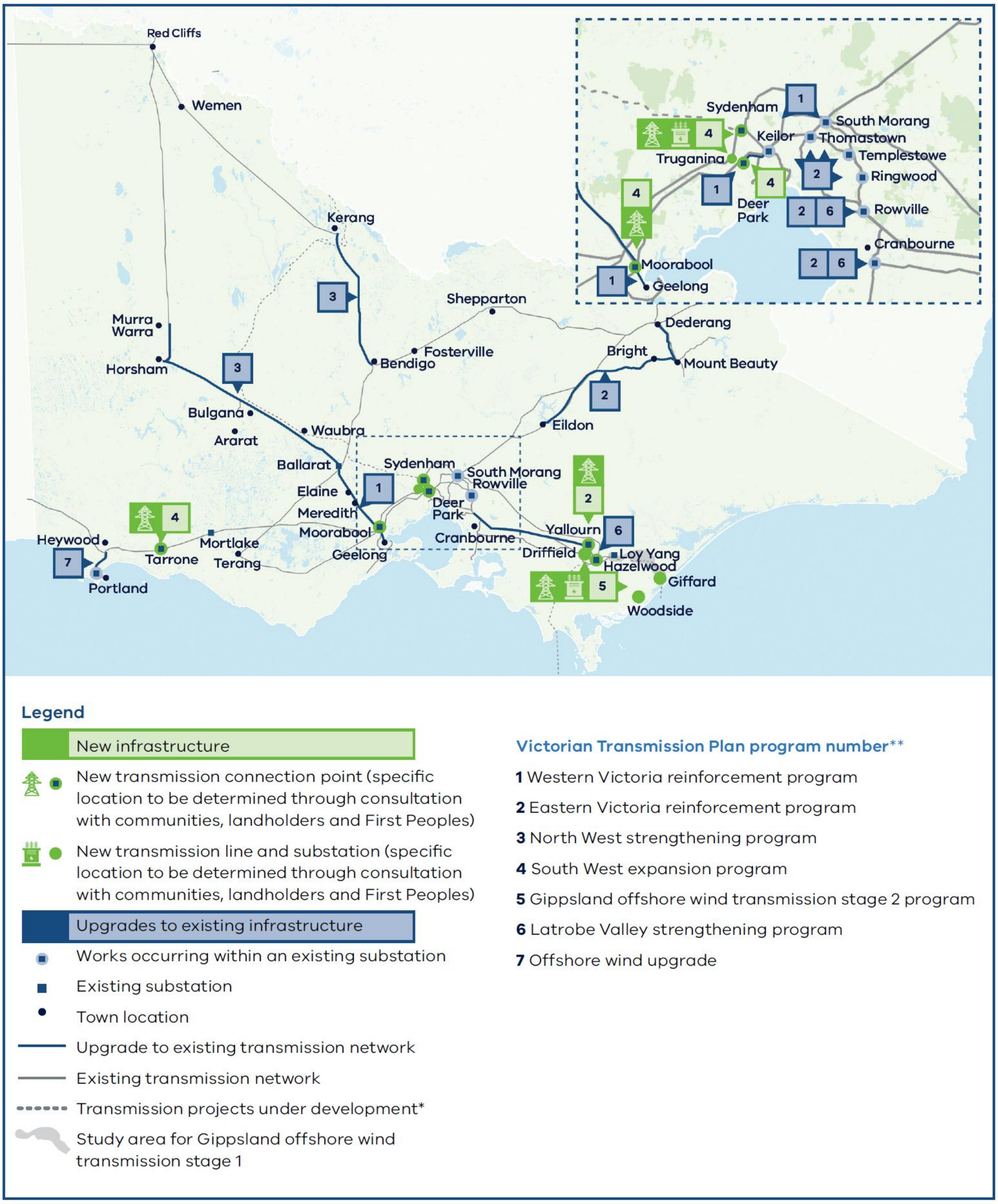


Figure 4: Proposed Renewable Energy Zones for Victoria

The plan also identifies seven transmission infrastructure programs that are required over the next 15 years to enable the development of new renewable energy sources. The programs build on projects that are already under development or in construction. This includes Western Renewables Link (WRL), Victoria to New South Wales Interconnector West (VNI West), Marinus Link and Gippsland offshore wind transmission stage 1. The projects range from upgrades within existing terminal stations to reconstruction of existing transmission infrastructure and 4 new transmission projects.

Figure 5 below shows the location of the plan's seven priority transmission programs.



*This includes transmission projects defined as Committed and Anticipated or Actionable under the Australian Energy Market Operator's 2024 Integrated System Plan. This map displays proposed alignments for Marinus Link, Victoria to New South Wales Interconnector West (VNI West), Western Renewables Link and the Gippsland offshore wind transmission stage 1. The Renewable Energy Zone Development Plan stage 1 project includes several network augmentations that are not included in this map.
** Each program includes multiple transmission projects. See Appendix A for further details about the proposed works included in each program.

Figure 5: Priority transmission programs identified in the 2025 Victorian Transmission Plan

VicGrid's 2025 Victorian Transmission Plan is available at: https://www.energy.vic.gov.au/renewable-energy/vicgrid/the-victorian-transmission-plan.

2.5 Reverse power flows at terminal stations

During periods of low local demand and/or high local generation where consumers are self-reliant on distributed PV, combined with utility-scale distribution generation, power can flow from the distribution network up into the shared transmission network, reversing the traditional flow where the distribution network typically draws power from the transmission network.

These reverse power flow conditions, together with lightly loaded transmission lines, can lead to increased need for operational management (including voltage management) in the transmission network, due to limitations in reactive support and/or onload tap ranges available at the connection points. Reverse power flow also affects the transformers' cyclic ratings, as transformers are typically de-rated to their nameplate rating during reverse power flow[21].

AEMO's October 2025 Victorian Network Performance and Insights Report[22] notes that an increasing number of distributed generators (including distributed PV) connecting at the distribution level has led to reverse power flows at many terminal stations. The table below (reproduced from the 2025 Victorian Network Performance and Insights Report) shows the terminal stations and the number of hours that reverse flows occurred over the last six years, and the primary cause of those reverse flows.

The table shows that reverse power flows were observed at 18 terminal stations in 2024/25, with Tyabb Terminal Station and Ringwood Terminal Station recording reverse power flows for the first time. The total hours of all stations' reverse power flows increased by 11% compared to 2023-24. Shepparton Terminal Station experienced an increase of over 1,000 hours in reverse flows compared to last year, predominantly due to the newly commissioned Girgarre Solar Farm connection in early 2024.

21 Section 4.2 provides further information on transformer ratings.

22 See 2025-victorian-network-performance-and-insights-report.pdf

Table 2: Annual statistics of reverse flows at identified terminal stations

Terminal station	Hours with reversed flows						Primary cause
	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	
Wemen 220/66 kV	3,241	3,546	3,053	3,610	3,082	3,096	Distribution network connected generation
Terang 220/66 kV	2,905	2,343	2,626	2,350	1,805	1,854	Distribution network connected generation
Kerang 220/66/22 kV	2,646	2,657	2,606	2,999	2,974	2,738	Distribution network connected generation
Horsham 220/66 kV	827	290	680	426	319	375	Distribution network connected generation
Red Cliffs 220/66/22 kV	477	1,933	2,192	2,636	2,121	2,381	Distribution network connected generation
Shepparton 220/66 kV	940	1,534	1,551	1,445	1,369	2,424	Distribution network connected generation
Ballarat 220/66 kV	838	1,912	1,659	1,589	1,395	1,568	Distribution network connected generation
Glenrowan 220/66 kV	0	592	2,582	2,617	2,739	2,707	Distribution network connected generation
South Morang 220/66 kV	0.5	14	56	84	266	423	Distribution network connected generation
Mount Beauty 220/66 kV	0	12	1,632	1,343	1,767	1,364	Distribution network connected generation
Bendigo 220/66 kV	0	4	24	39	144	205	Distributed PV
Cranbourne 220/66 kV	0	0	4	15	254	429	Distributed PV
Deer Park 220/66kV	0	0	18	35	203	382	Distributed PV
Morwell 220/66kV	1	2	38	66	137	174	Distribution network connected generation
Wodonga 330/22 kV	0	NA*	201	279	542	635	Distributed PV
Geelong 220/66 kV	0	0	0	0	0.5	2	Distributed PV
Tyabb 220/66 kV	0	0	0	0	0	443	Distributed PV
Ringwood 220/66/22 kV	0	0	0	0	0	3	Distributed PV
Total	**11,876**	**14,839**	**18,922**	**19,533**	**19,114**	**21,203**	

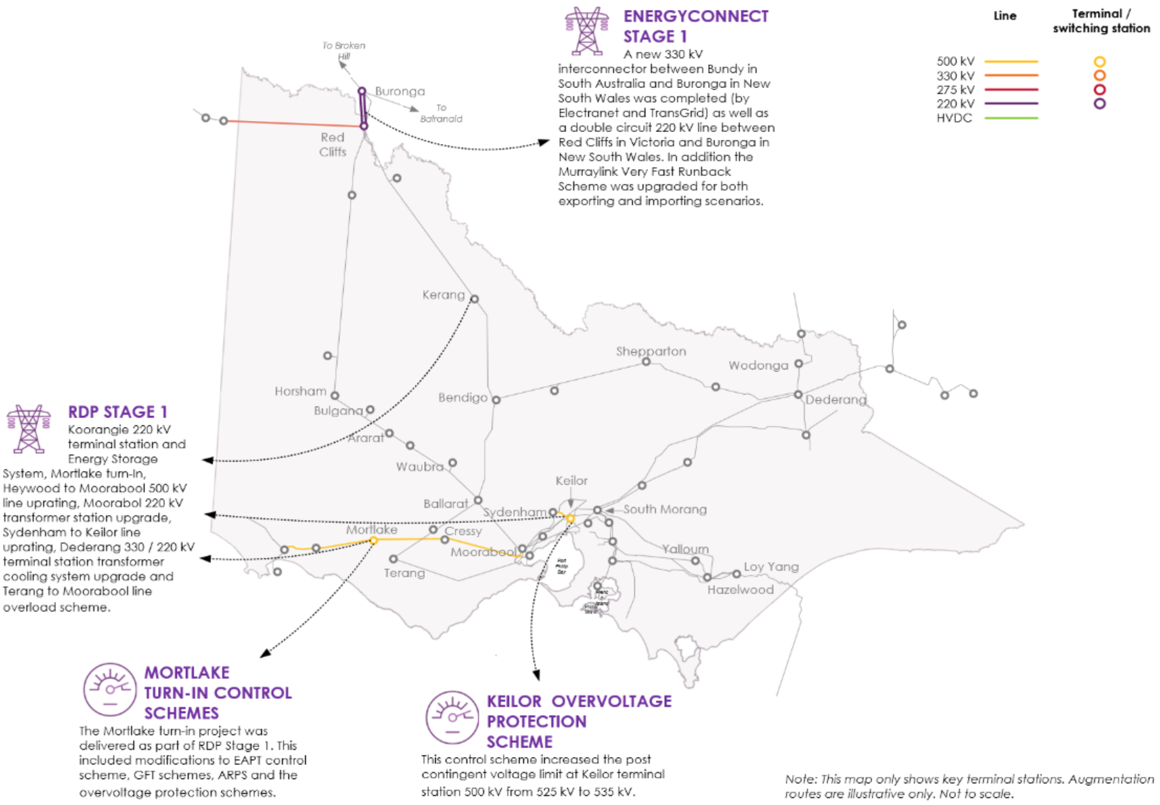
*Data quality issues prevented determination of reverse flow hours for this terminal station over this period.

Source: AEMO, 2025 Victorian Network Performance and Insights Report, page 16.

2.6 AVP's Victorian Annual Planning Report

AVP's Victorian Annual Planning Report was published in October 2025, prior to responsibility for planning the shared transmission network being transferred from AEMO to VicGrid. The report was prepared in accordance with clauses 5.12.1 and 5.12.2 of the Rules.

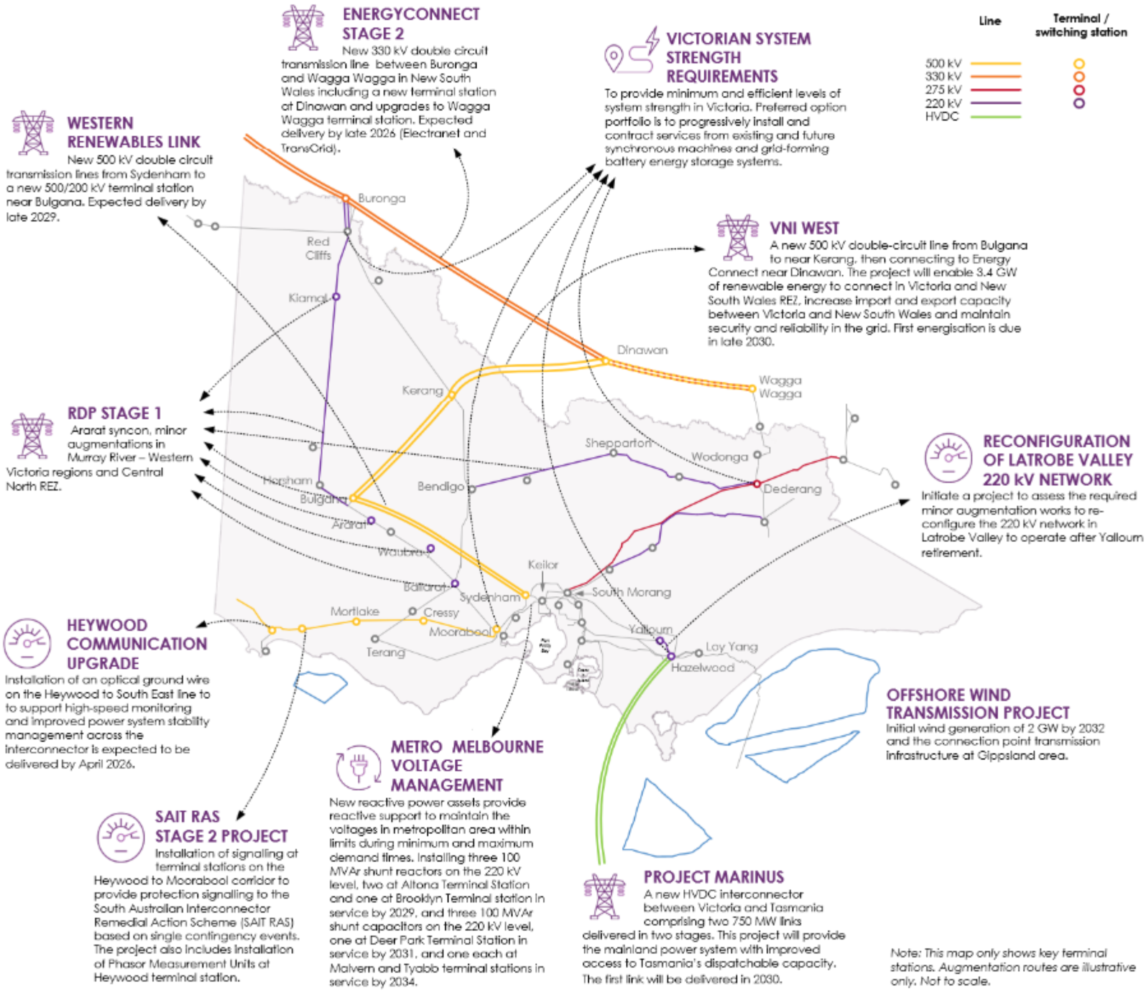
Planned projects that are near completion or have been completed recently are shown in the figure below.



Source: AEMO, 2025 Victorian Annual Planning Report, page 40.

Figure 6: Newly completed / near complete transmission projects for Victoria

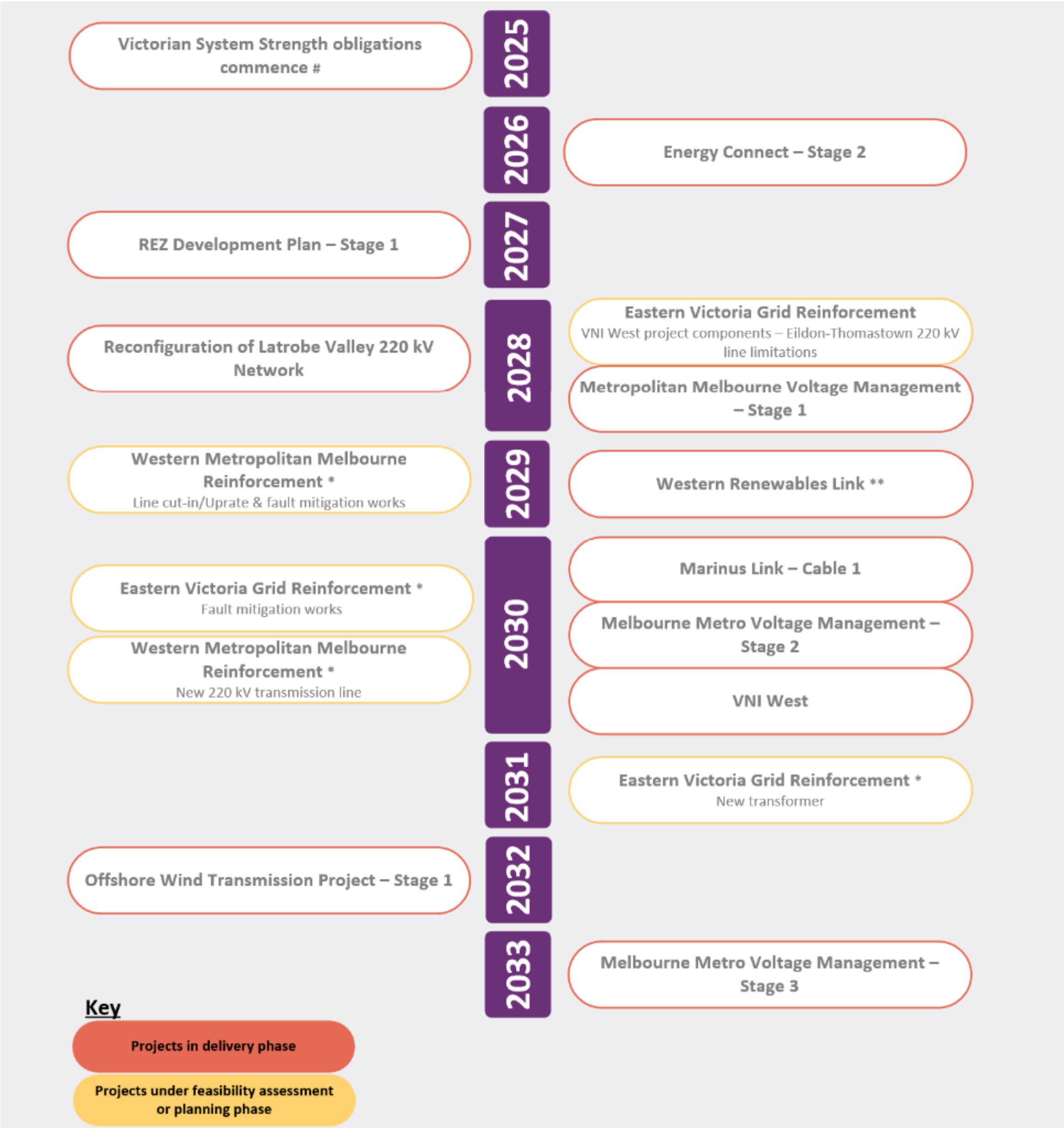
Projects that are currently in progress under the plan are shown in the figure below.



Source: AEMO, 2025 Victorian Annual Planning Report, page 41.

Figure 7: In-progress Transmission Development Plan projects for Victoria

The timeline for delivery of projects under the plan is outlined in the figure below.



Note: Projects that appear in both the Transmission Development Plan and VicGrid's VTP may have different timelines due to different inputs and assumptions. As these projects become committed, the timelines will align in future publications.
Provision of system strength services occurs progressively in the planning horizon. Refer to VAPR Section 3.1.2 for specific details of the preferred option portfolio.
* Western Metropolitan Melbourne Reinforcement and Eastern Victoria Grid Reinforcement options and timings are based on published PSCRs and are subject to change as each RIT-T progresses that will confirm preferred options and timing.
** WRL was originally anticipated to be completed in mid-2027 as shown in previous VAPR publications, however the anticipated completion date has now shifted to having first energisation in late 2029.

Source: AEMO, 2025 Victorian Annual Planning Report, page 39.

Figure 8: Timeline of Transmission Development Plan projects for Victoria

The Victorian Annual Planning Report is consistent with AEMO's current Integrated System Plan (**ISP**) for the NEM, which was published in June 2024.[23] The ISP shows the significant developments that are taking place across the transmission sector, which provides important context and background for the transmission connection planning addressed in the remainder of this report.

23 See [AEMO | 2024 Integrated System Plan (ISP)]

3 PLANNING METHODOLOGY

3.1 Transmission connection planning approach and planning standard

The DBs' planning of transmission connection is focused in part on delivering an optimal level of supply reliability to customers[24]. In this regard, the costs associated with transmission connection facilities comprise two parts:

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

In terms of supply reliability, 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 concept is illustrated in the figure below.

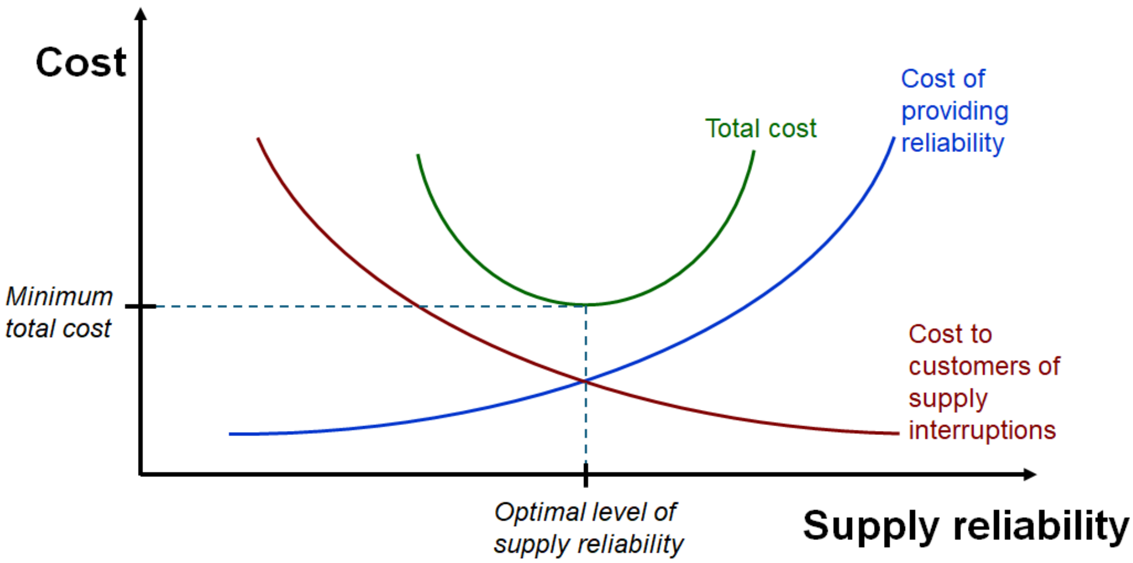


Figure 9: Balancing the trade-off between cost of service and reliability

In accordance with the requirements of the RIT-T, the DBs' transmission connection investment decisions aim to maximise the present value of net economic benefit, where the investment options may include network and non-network solutions. This objective is

24 Section 3.3 explains that the DBs' transmission connection planning also considers the costs to customers and the market of CER export curtailment due to network limitations.

met by adopting a probabilistic planning approach, which AEMO has applied[25] in planning the shared transmission network[26].

Under the probabilistic approach, deterministic standards (such as N-1) are not applied. An N-1 deterministic standard means that after an unexpected outage of a single system component, the transmission system should still be able to operate within limits without load curtailment. Instead of applying a deterministic standard, 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 (or other intervention action) that might otherwise proceed if a deterministic standard were applied. This is because:

- in a network planned using the probabilistic approach, there may be conditions under which some or all of the network service cannot be provided with an element of plant 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 or constrained off is not high enough to justify the additional investment, taking into account the probability of a forced outage of a particular element of the transmission system.

The use of a probabilistic approach involves 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. Instead, clause 13.3.1 of the Victorian EDCoP sets out the following broad requirements relating to supply reliability:

> "A distributor must use best endeavours to meet targets determined by the AER in the current distribution determination and targets published under clause 13.2.1 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 investment, subject to meeting the technical and other standards set out in the Rules and other applicable regulatory instruments including the Victorian EDCoP.

Clause 19.3.2(c) of the Victorian EDCoP requires this report to set out the DBs' transmission connection planning standards. The RIT-T is the transmission connection

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25 On 1 November 2025, responsibility for planning the Victorian shared transmission network was transferred from AEMO to VicGrid. A copy of the Victorian transmission planning criteria can be obtained from:
http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf

26 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.

planning standard that the DBs apply. While this report does not itself apply the RIT-T, the methodology described above is consistent with this planning standard.

3.2 Value of customer reliability

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. This is referred to as the value of customer reliability (**VCR**).

Under clause 8.12 of the Rules, the AER is responsible for developing and publishing a VCR methodology and VCR estimates. In December 2024, the AER published its Final Report on the 2024 VCR[27].

For this report, the DBs have adopted the VCR sector estimates published by the AER in its December 2024 VCR Final Report. These values are shown in the table below.

Table 3: VCR estimates by sector

Sector	VCR for this report ($/kWh) Source: AER, Final Report on VCR values, December 2024	Change in sector VCR from escalated 2019 value to 2024 value
Residential (Victoria)	49.23	+96%
Agricultural (NEM)	22.25	-50%
Commercial (NEM)	34.39	-34%
Industrial (NEM)	33.49[28]	-55%

Table 3 shows that the sector VCR estimates published by the AER in 2024 differ from its previous estimates (obtained in 2019). This observation underscores the importance of sensitivity testing in investment decision analyses such as the RIT-T.

Commenting on the changes in VCR estimates between 2024 and its previous (2019) survey, the AER noted that[29]:

> "The key findings from our survey results are the following, noting that the specific VCR outcomes for each segment are a combination of movements in all the underlying calculation components (willingness to pay, unserved energy and outage frequencies) across a range of different outage scenarios.
>
> - The 2024 residential VCR are higher than the 2019 VCR survey (across the NEM, state and territory aggregate VCR, with one exception at the climate zone level). The main drivers of this change are an increase in residential willingness to pay and a decrease in residential unserved energy.

27 See: AER, Final Report on VCR values, December 2024, at [Final report | Australian Energy Regulator (AER)]

28 For customers with a maximum demand below 10 MVA.

29 AER, Final Report on VCR values, December 2024, page 4.

- The 2024 business (less than 10 MVA) VCR are significantly lower than the 2019 VCR survey. This change has been driven primarily by changes in business customers' willingness to pay as a proportion of the customer bill, which declined between 2024 and 2019. While we had a larger sample size in 2024 than in 2019, changes in the sampling composition may have potentially shifted the results."

The AER's Final Report provides the following guidance on how the VCR should be applied[30]:

> "When applying the VCR, the value used should be reflective of the customer composition on the network and the reliability preferences of the customers who are affected by a proposed investment."

In accordance with the AER's guidance, this report applies VCR values for each terminal station that reflect the composition of station energy consumption by sector.

3.3 Customer export curtailment value

On 12 August 2021, the AEMC made a final determination on its "Access, pricing and incentive arrangements for distributed energy resources" Rule change[31]. In its determination, the AEMC stated on page ii:

> "The final rules [clarify] that export services are part of the core services to be provided by DNSPs. By removing references in the NER that are specific to the direction of energy, the regulatory framework will give clear guidance that 'distribution services' relate not only to sending energy to customers, but also to customers exporting the energy they generate. For customers, this gives clarity around their rights to access export services. For DNSPs, this provides clarity around what they are expected to provide in delivering those services."

Under the Rule, the AER is required to develop customer export curtailment values (**CECVs**), which are an estimate of the detriment to customers and the market of export curtailment due to network limitations (in $ per kWh of exports curtailed). CECVs are intended to play a similar role to the VCR in evaluating the net benefit of reducing or removing network constraints. For instance, it is intended that the CECVs will be used to assess whether proposed steps to reduce export curtailment - such as increasing Consumer Energy Resource **(CER)** hosting capacity - can be economically justified.

In June 2022, the AER published its Customer Export Curtailment Value Methodology[32]. At the same time, the AER also published a DER[33] Integration Expenditure Guidance Note[34], which provides guidance on how distribution network service providers should:

- develop business cases for network investment integrating higher levels of CER and quantify CER values;

30 AER, Final Report on VCR Values, December 2024, page 3.

31 AEMC, Rule Determination, National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021, 12 August 2021.

32 Customer export curtailment value methodology | Australian Energy Regulator (aer.gov.au)

33 "Distributed Energy Resources", which is analogous to CER.

34 Distributed energy resources integration expenditure guidance note | Australian Energy Regulator (AER)

- develop CER integration plans and investment proposals; and
- quantify CER benefits in a cost-benefit analysis.

It is possible that in the future, the obligation on distributors to efficiently integrate higher levels of CER into their distribution networks may give rise to a need to reduce export curtailment at some transmission terminal stations. The risk assessments provided in this report identify those terminal stations where export curtailment may be an issue. In any such cases, further detailed analysis of whether export curtailment would justify additional investment in terminal station capacity will be undertaken as part of a RIT-T assessment.

3.4 Taking carbon emission reductions into account

In late 2023, the National Electricity Law was amended to introduce an emissions reduction element into the National Electricity Objective (**NEO**). The NEO now requires proponents to consider greenhouse gas emissions reductions in the RIT-T.

In the Rules, the definition of “net economic benefit” has been amended so that in addition to including net benefits to NEM participants, it also includes emissions reduction benefits whether or not those benefits accrue to NEM participants.

In May 2024, the AER published its final guidance and explanatory statement on applying a value of emissions reduction.[35] That document includes a table of interim values of emissions reduction which apply until 30 June 2026 or until they are superseded. It is intended that the interim values will be used by network businesses in their investment evaluations.

In November 2024, the AER published amendments to the RIT-T application guidelines and RIT-T instrument document.[36] The amendments reflect the amended NEO, and the updated Rules definition of “net economic benefit”. Accordingly, the RIT-T guidelines incorporate a new class of benefit (“changes in Australia’s greenhouse gas emissions”) which is to be considered in a RIT-T. They also include guidance and worked examples on how emissions reductions are to be valued and included in a RIT-T evaluation.

The risk assessments provided in this report identify those terminal stations where emission reduction benefits may be material. In any such cases, the evaluation of emission reduction benefits associated with options to address a transmission connection constraint will be undertaken when the RIT-T is applied, in accordance with the RIT-T guidelines.

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35 AER - Valuing emissions reduction - Final guidance and explanatory statement - May 2024 | Australian Energy Regulator (AER)

36 2024 Review of the cost benefit analysis and regulatory investment test guidelines | Australian Energy Regulator (AER)

4 Inputs and assumptions for this planning report

4.1 Introduction

This chapter describes the inputs and assumptions that underpin the risk assessment for each terminal station.

The high-level analysis presented in this report focuses on risks to supply reliability that relate to the capacity and reliability of transformers only. Typically, there are risks to 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 primarily driven 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.

The following key data are presented in this report for each Terminal Station where a spare transformer is available to be installed following the failure of an in-service transformer:

- ***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[37] of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.65 months (as discussed in section 4.7 below), and no other mitigation action is taken. This measure indicates 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 measure indicates 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 for 2.65 months because of a major outage.

Where a spare transformer is not available, the annual duration of a major transformer failure is assumed to be 12 months, and the ***energy at risk*** and ***expected unserved energy*** are calculated for each year on that basis. Further information on the availability of spare transformers is provided in section 4.6.

Where material constraints are expected to emerge over the forecast period, risk assessments for the relevant terminal stations provide estimates of energy at risk and expected unserved energy based on the 50th percentile and 10th percentile demand

[37] The term "major outage" refers to an outage resulting from a significant failure within the transformer.

forecasts. Consideration of energy at risk and expected unserved energy at these two forecasts of demand 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 under higher demand conditions (namely, 10th percentile levels).

Alongside that information, risk assessments will also provide a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively), in accordance with the approach adopted by VicGrid's predecessor, AEMO[38].

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 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 50th percentile demand forecast relates to a maximum average temperature that will be exceeded, on average, once every two years. Therefore, by definition, actual demand in any given year has a 50% probability of being higher than the 50th percentile demand forecast[39].

4.2 Plant ratings and 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 figure below.

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38 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

39 Conversely, there is also a 50% chance that actual demand will be lower than the forecast in any one year.

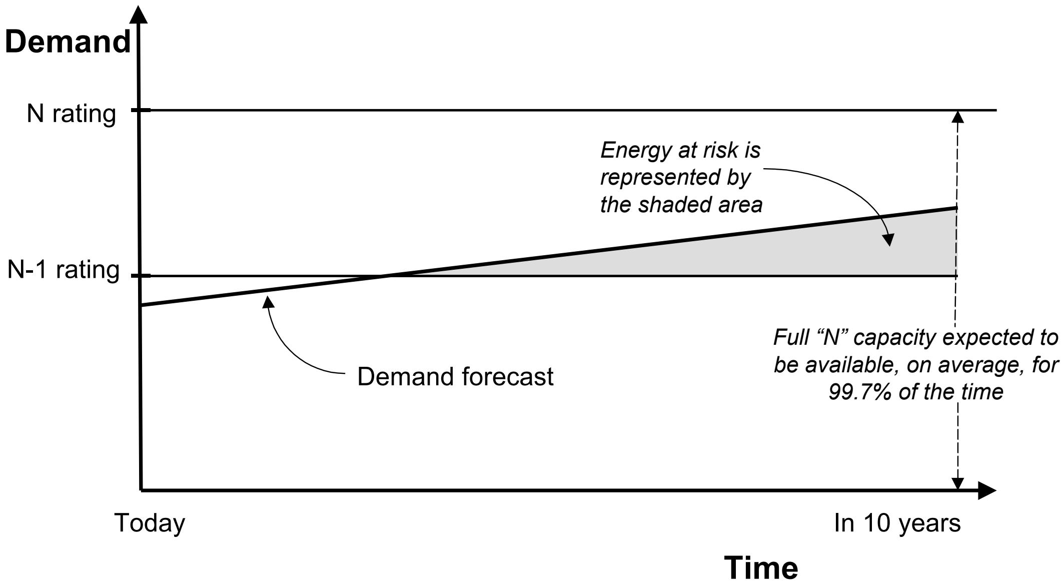

Figure 10: Relationship between N rating, N-1 rating and energy at risk

The owners of the connection assets (AusNet Transmission Group and TransGrid) are responsible for determining the ratings of connection assets.

As noted in section 2.5, reverse power flows are now observed at 18 terminal stations. Reverse flows associated with substantial intermittent generation output may result in significantly increased variability of transformer loadings, increased transformer utilisation, and reduced time for transformers to cool down between periods of high loading in either direction. AusNet Transmission Group has advised that where significant reverse power flows are observed, the existing cyclic ratings no longer apply to these transformers because they no longer exhibit a predictable cyclic loading pattern. Instead, the transformer's nameplate rating is adopted for planning and operational purposes.

AusNet Transmission Group has recently completed a review of transformer load profiles and applicable station ratings. The latest ratings were advised by AusNet Transmission Group in October 2025, and these have been applied in the relevant risk assessments presented in this report.

AusNet Transmission Group has advised that all station ratings (apart from at RWTS) only take into consideration the limitations posed by the connection transformer elements and exclude other plant and equipment at the station that may limit the import/export ratings of the station further. AusNet Transmission Group is currently reviewing the ratings of plant and equipment at all terminal stations; hence subsequent station ratings may be impacted accordingly.

4.3 Demand forecasts

The demand forecasts used in the preparation of this report are referred to as the Victorian Terminal Station Demand Forecasts (**TSDFs**). The TSDFs are prepared by the Victorian DBs and are published alongside this report.

In accordance with the requirements of clause 19.3.2(a) of the Victorian EDCoP, data showing the historical and forecast demand and capacity at each transmission connection are presented for each terminal station in the individual risk assessments that form part of this report.

In April 2025, AEMO published its Transmission Connection Point Forecasts for Victoria (available at AEMO | Transmission Connection Point Forecasts for Victoria). AEMO's forecasts are based on information available to it as at 1 November 2024; those forecasts therefore do not reflect the latest actual data for summer 2024/25. The DBs' TSDFs take account of the latest available summer demand data. Moreover, AEMO's forecasts reflect terminal station demand that is coincident with Victorian demand whereas the DBs consider terminal station coincident demand, which is the more appropriate measure of maximum demand for connection planning purposes. Accordingly, the DBs consider it appropriate to adopt the TSDFs for the purpose of preparing this report.

As noted in section 2.2, data centre development is likely to make a material contribution to demand growth over the next decade. However, there is a high level of uncertainty associated with the magnitude and timing of demand increases that may be associated with new data centre development. For the purposes of this 2025 report, the following approach to forecasting data centre loads has been adopted:

- For terminal stations that supply Jemena's customers, Jemena has forecast its data centre loads by applying appropriate diversity factors, ramping profiles and load realisation factors. These forecasts are further adjusted by connection likelihood, based on the latest customer information and their progress through the connection process.

- For other terminal stations, the demand forecasts include only committed data centre block loads. For these terminal stations, "committed" block loads are those that meet AEMO's committed project criteria and/or have progressed to executed connection agreements. Accordingly, it is possible that the timing of some required terminal station augmentations indicated in this report may change, depending on the timing of commitment of new block loads and increased ramping of existing block loads.

While the forecasting approaches differ between terminal stations supplying Jemena's customers and those supplying the other DBs, each method is valid and reflects the current degree of confidence in the data centre load forecasts. The DBs will be working closely in advance of the 2026 Transmission Connection Planning Report to develop a common approach to forecasting new block loads, recognising that each DB is responsible for developing its own demand forecasts.

It is also noted that future data centre demand will be assessed at each terminal station through the RIT-T process, which must be completed to identify the preferred option to address an identified need. The RIT-T requires scenario analysis and sensitivity testing, which will ensure that projections of future data centre demand will be factored into the investment decision analysis at the relevant terminal station. It is likely, therefore, that the demand forecast for each terminal station will be revisited as part of any RIT-T process.

4.4 Impact of rooftop PV on estimates of energy at risk

As already noted, there has been an increasing prominence of distributed generation at the consumer end of the supply chain, including rooftop solar PV generation and utility scale renewable generation. Embedded renewable generation has the effect of reducing the energy consumption seen by the grid, and to a lesser degree, reducing the maximum demand at the transmission connection points[40].

In the event of a supply interruption, rooftop PV panels are tripped unless they have back-up battery systems configured and approved for island mode operation. Customers affected by such outages will experience a level of unserved energy equal to their total unserved consumption (that is, including the energy that would have been supplied by their PV panels and batteries). However, it is noted that most of the existing solar PV and battery installations are behind the meter. In other words, the electricity output is consumed by the customer without being measured by the customer's meter. As a result, the DBs have limited ability to quantify the native energy consumption before the solar PV and battery contribution.

As a consequence, the amount of unserved energy due to a network outage may be underestimated, as the total unserved energy will include some energy served by embedded generation in addition to the unserved energy resulting from the constraint at the transmission connection point. The impact of this issue is discussed in the individual risk assessments where it is considered to be material.

4.5 Assessing the costs of transformer outages

As explained in Section 4.1 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.

The DBs have considered whether this report should be expanded to include the costs of major outages under N-2 (second order contingency) conditions, and concluded that it is not necessary to do so. The principal reason for this conclusion 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. Section 3 of the Appendix contains a detailed example that illustrates this point.

4.6 Availability of spare transformers

AusNet Transmission Group has determined that it is economically efficient to hold spare transformers to reduce outage times for failed 150 MVA transformers. In October 2025, AusNet Transmission Group advised that:

40 This is due to the fact that the maximum demand typically occurs later in the afternoon or in the early evening when the output of rooftop solar PV is well below its peak.

- One of the two 220/66 kV 150 MVA metropolitan spare transformers will be available for the 2025/26 and 2026/27 summer periods to manage the risk of a metro transformer failure, as one of the spare transformers has recently been relocated to CBTS for an augmentation project. This spare will be replenished in early 2027, and two metropolitan spare 150 MVA transformers will be available from the 2027 winter period onwards. The metropolitan spare transformers will be located at Thomastown and Heatherton terminal stations.

- Both 220/66/22 kV 150 MVA country spare transformers are available to manage the risk of a country transformer failure and they are located at Keilor and South Morang terminal stations.

- A spare 66/22 kV transformer is located at Brooklyn Terminal Station. This transformer serves as a spare for 66/22 kV transformers including those at Malvern Terminal Station.

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.

There are several AusNet Transmission Group terminal stations for which a stock of spare transformers is not held, as AusNet Transmission Group has determined that the cost of holding a spare is not warranted given the low expected unserved energy under N-1 conditions. These relevant stations and assumptions in this planning report are set out below:

- The metropolitan 220/66 kV connection stations with 225 MVA transformers (located at Brunswick, Malvern, Richmond, South Morang and West Melbourne). A major failure of one of these transformers would require the procurement of a replacement transformer. The outage of a 225 MVA transformer is assumed to be 12 months for the purpose of calculating expected transformer unavailability per transformer-year.

- The metropolitan 220/22 kV connection stations (Ringwood, Brunswick, Richmond, West Melbourne and Brooklyn). For these stations, an in-service 'hot' spare is normally provided by one of the 220/22 kV transformers at Brunswick. The timeframes for deploying the 'hot' spare may exceed one calendar month. For the risk assessments for these stations, 2.65 months is considered to be a reasonable estimate of the weighted average duration of a major outage.

A spare 225 MVA transformer suitable for installation at DPTS is not presently available. The DB responsible for planning DPTS (Powercor) has adopted the assumption that a major transformer failure would not be repairable, and therefore a replacement transformer would need to be procured in the event of a failure. Powercor is presently examining the economic case for acquiring a spare 225 MVA transformer for DPTS.

4.7 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. Except for DPTS, which is owned by TransGrid, the reliability data for terminal station transformers has been established and agreed with the asset owner, AusNet Transmission Group. The 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.

As noted in section 4.6, AusNet Transmission Group has determined that it is economically efficient to hold spare 150 MVA transformers to reduce outage times for failed transformers. Where a spare transformer has been procured, the average outage duration for a major transformer failure is 2.65 months.

Where a spare transformer is not available at an AusNet Transmission Group-owned station, as is the case for the 225 MVA transformers at BTS 66, MTS 66, RTS 66, SMTS and WMTS 66, the annual duration of a major transformer failure is assumed to be 12 months. AusNet Transmission Group’s assessment is that the expected unserved energy at these stations does not justify holding a spare transformer.

Similarly, for DPTS, Powercor has assessed that the expected unserved energy does not at present justify the acquisition of a spare transformer, so the annual duration of a major transformer failure at DPTS is assumed to be 12 months. As noted in section 4.6 above, Powercor is presently examining the economic case for procuring a spare 225 MVA transformer for DPTS.

Based on these assumptions, the reliability data adopted to produce this report is summarised in the following table.

Table 4: Base Reliability Data

Major plant item: Terminal station transformer		Interpretation
Major outage rate for transformer	1.0% per annum	A major outage is expected to occur once per 100 transformer-years. Therefore, in a population of 100 terminal station transformers, you would expect one major failure of any one transformer per year.
Weighted annual average of major outage duration where a spare is available	2.65 months	On average, 2.65 months is required to return the transformer to service (if repair is possible) or to replace the transformer with a spare transformer, during which time, the transformer is not available for service.
Annual outage duration where a spare is not available	12 months	Where a spare is not available, it is expected that the transformer will not be available for 100% of the year after a major failure.
Expected transformer unavailability due to a major outage per transformer-year where a spare is available	0.01 x 2.65/12 = 0.221% per annum	On average, where a spare is available, each transformer would be expected to be unavailable due to major outages for 0.221% of the time, or 19 hours in a year.
Expected transformer unavailability due to a major outage per transformer-year where a spare is not available	0.01 x 12/12 = 1% per annum	On average, where a spare is not available, each transformer would be expected to be unavailable due to major outages for 1% of the year, or 88 hours in a year.

In October 2025, AusNet Transmission Group confirmed that the transformer outage rate data and the estimated average time to restore a failed transformer to service (shown in the above table) are reasonable for the purpose of preparing the transmission connection asset risk assessments, and it was noted that[41]:

- Recent changes in the Australian transformer industry have resulted in reduced capability to undertake repairs to transformers that are subject to a major failure, and therefore, supply is more likely to be restored by installing a strategic spare transformer than by undertaking major repairs of the transformer.

- Recent experience from major transformer failures has demonstrated that it is typically more economical to replace rather than repair a transformer following a major failure, particularly for transformers that have reached or are approaching the end of their expected service life.

- The estimated weighted average duration of a major outage is largely determined by the expected time that it takes to replace a failed transformer with a strategic spare (rather than the time taken to repair the transformer following a major transformer failure). Whilst it is expected to take around one month to replace a transformer with a strategic spare, it may take more than 12 months to procure a replacement transformer should no spare transformer be available at the time of the transformer failure. The 2.65 months that is being used for the risk assessments where a strategic spare transformer has been procured is a weighted average duration, which recognises the possibility that a strategic spare may not be available at the time of the major transformer failure.

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 reliability data contained in this section.

4.8 Treatment of load transfer capability

Many terminal stations have 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 can 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 (where short-term transfer capability is available) to reduce unserved energy and the impact of an outage. The risk assessments presented in this 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 effect 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

41 AusNet Transmission Group uses asset condition-based failure risk information for asset replacement decisions. Joint planning is undertaken with the DBs to coordinate connection asset terminal station augmentation works with AusNet Transmission Group’s replacement plans.

abnormal configurations which may be 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.

Where short-term load transfer capability may be available, the relevant risk assessment identifies load transfer as an operational solution to mitigate the severity of a major outage.

4.9 Indicative costs of network options for alleviating constraints

The risk assessments included in this report describe the network augmentation requirements (if any) and the estimated annualised costs of the augmentation works.

We have adopted an annuity approach to estimating the annualised costs, which means that the cost is constant in real terms throughout the estimated life of the asset (45 years for the purpose of this report). The annualised cost calculation also assumes a real pre-tax discount rate of 7%[42] and an annual operating cost that is 1% of the project's capital costs. Using these inputs for this report, the annualised total cost is estimated to be 8.3% of the project's capital cost.

This cost estimate also 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 2029 to 2032 is less valuable today than one which defers a similar network augmentation from, say, 2026 to 2029. These issues should be considered by proponents of non-network solutions in assessing the implications of this report.

4.10 Indicative timeframes for implementing network options

Any 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 range from two years up to five years, taking into account the need to obtain local authority planning consent[43]. Given this consideration, the individual risk assessment commentaries for each terminal station:

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

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42 In its 2025 Inputs, Assumptions and Scenarios Report, AEMO adopts a central discount rate of 7% real pre-tax. Clause 18 of the RIT-T requires a RIT-T proponent to adopt the discount rate from the most recent Inputs, Assumptions and Scenarios Report unless it provides demonstrable reasons for why a variation is necessary, in which case this variation must be consistent with clause 19, which states: "The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used must be consistent with the cash flows being discounted". AEMO's 2023 Inputs, Assumptions and Scenarios Report is the most recent report. Accordingly, this report applies a discount rate of 7% real pre-tax.

43 Section 1.5 provides a more detailed description of the processes and timeframes involved in implementing transmission connection projects.

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

4.11 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 “2025/26”, or “summer of 2025/26”.

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 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 2025/26, for instance), the peak would typically be expected to occur in the second year (in this example, 2026), and the relevant data for 2025/26 would be shown in the accompanying tables and charts as 2026.

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 A1: Transformer Failure Data

	PROPORTION OF MAJOR FAILURES	MEAN OUTAGE DURATION
Restore supply with a strategic spare transformer	0.85 of failures	1 months
Restore supply with a new transformer or repaired transformer	0.15 of failures	12.0 month

Mean duration of a major failure = (0.85*1.0 month) + (0.15*12.0 months) = **2.65 months**

2. Expected transformer unavailability calculation

The table below shows the calculation of the "Expected Transformer Unavailability" for a terminal station with two transformers, using the reliability data contained in Section 4.7.

Table A2: Expected Transformer Unavailability

Expected transformer unavailability due to major outage per transformer-year (Refer to Section 4.7 for the reliability statistics)	A	0.221%
Number of transformers	B	2
Expected unavailability of one transformer (probability of being in state N-1)	**C=A*B**	**0.442%**
Expected unavailability of both transformers (probability of being in state N-2)[44]	**D=A*A**	**0.00049%**

44 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.

3. Example calculation of expected costs of first and second order contingencies

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:

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 = $35,000 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. Detailed calculations are shown for the first year.

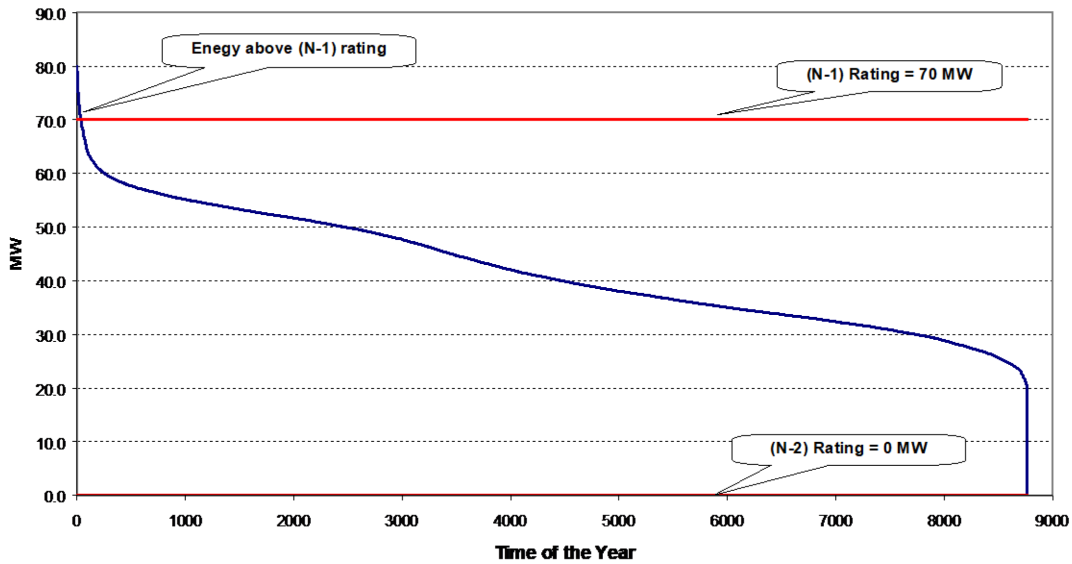


Figure A1: Annual Load Duration Curve

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

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)

Expected Unserved Energy = (Energy above N-1 Rating) * (N-1 Probability)
= (132 MWh) * (0.442%) = 0.6 MWh

Customer Value = (Expected Unserved Energy) * (VCR)
= (0.6 MWh) * ($35,000 per MWh) = $20,420

Second Order Contingency (N-2)

Expected Unserved Energy = (Energy above N-2 Rating) * (N-2 Probability)
= (367,877 MWh) * (0.00049%) = 1.8 MWh

Customer Value = (Expected Unserved Energy) * (VCR)
= (1.8 MWh) * ($35,000 per MWh) = $63,000

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 second order contingency is comparable to the value of expected unserved energy for a first 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 first order contingency grows at a much faster rate than the value of expected unserved energy for a second order contingency.

- The value of expected unserved energy associated with second 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.

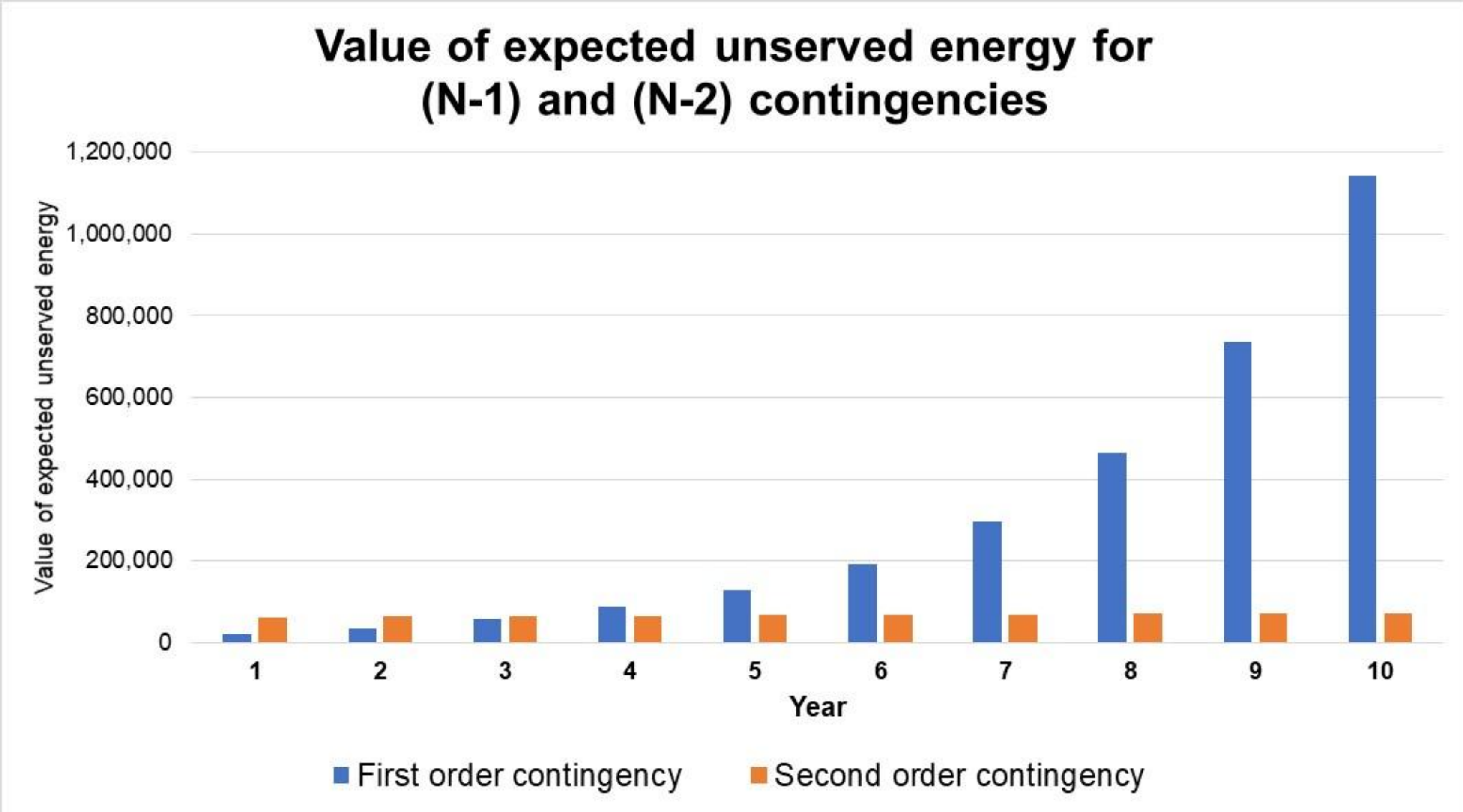


Figure A2: Value of expected unserved energy

Table A3: Summary of Risk Assessment Results for a 2-Transformer Terminal Station Example

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Maximum Demand (MW)	**80.0**	**82.4**	**84.9**	**87.4**	**90.0**	**92.7**	**95.5**	**98.4**	**101.3**	**104.4**
N-1 Risk Assessment										
Rating (MW)	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Demand above Rating (MW)	10.0	12.4	14.9	17.4	20.0	22.7	25.5	28.4	31.3	34.4
Energy above Rating (MWh)	132	231	374	565	838	1,253	1,914	3,003	4,759	7,393
Probability	0.442%	0.442%	0.442%	0.442%	0.442%	0.442%	0.442%	0.442%	0.442%	0.442%
Expected Unserved Energy (MWh)	0.6	1.0	1.7	2.5	3.7	5.5	8.5	13.3	21.0	32.7
Customer Value ($)	20,420	35,736	57,858	87,406	129,639	193,839	296,096	464,564	736,217	1,143,697
N-2 Risk Assessment										
Rating (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand above Rating (MW)	80.0	82.4	84.9	87.4	90.0	92.7	95.5	98.4	101.3	104.4
Energy above Rating (MWh)	367,877	373,395	378,996	384,681	390,452	396,308	402,253	408,287	414,411	420,627
Probability	0.00049%	0.00049%	0.00049%	0.00049%	0.00049%	0.00049%	0.00049%	0.00049%	0.00049%	0.00049%
Expected Unserved Energy (MWh)	1.8	1.8	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.1
Customer Value ($)	63,091	64,037	64,998	65,973	66,963	67,967	68,986	70,021	71,071	72,138

RISK ASSESSMENTS FOR TERMINAL STATIONS (IN ALPHABETICAL ORDER)

Set out on the following pages are the detailed risk assessments and a description of the options available for the 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 annualised costs of the augmentation works are identified.

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, Bacchus Marsh, Brooklyn, Laverton North, Tottenham, Footscray and Yarraville. It is the main source of supply for 64,022 customers. The station is shared by Jemena Electricity Networks (39%) and Powercor (61%).

The forecasts for each DB supplied from this station have been prepared using different approaches. The Jemena forecasts have applied a methodology to include diversified non committed block loads. The forecasts prepared by Powercor have only included committed block loads, noting that there are significant block loads progressing through application processes. Non-network proponents should note that the use of non-committed block loads increases the uncertainty of the nature and timing of the augmentations.

Embedded generation

A total of 123.7 MW capacity of embedded generation is installed on the sub-transmission and distribution systems connected to ATS-BLTS. It consists of:

- 45.7 MW of large scale (>1 MW) embedded generation, which includes 40 MW in the Powercor distribution system and 5.7 MW in the Jemena distribution system; and
- about 78 MW small-commercial and residential rooftop solar PV (<1 MW), which includes 45 MW in the Powercor distribution system and 33 MW in the Jemena distribution system.

Magnitude, probability and impact of constraints

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. BLTS has two 150 MVA 220/66 kV transformers supplying the BLTS 66 kV bus.

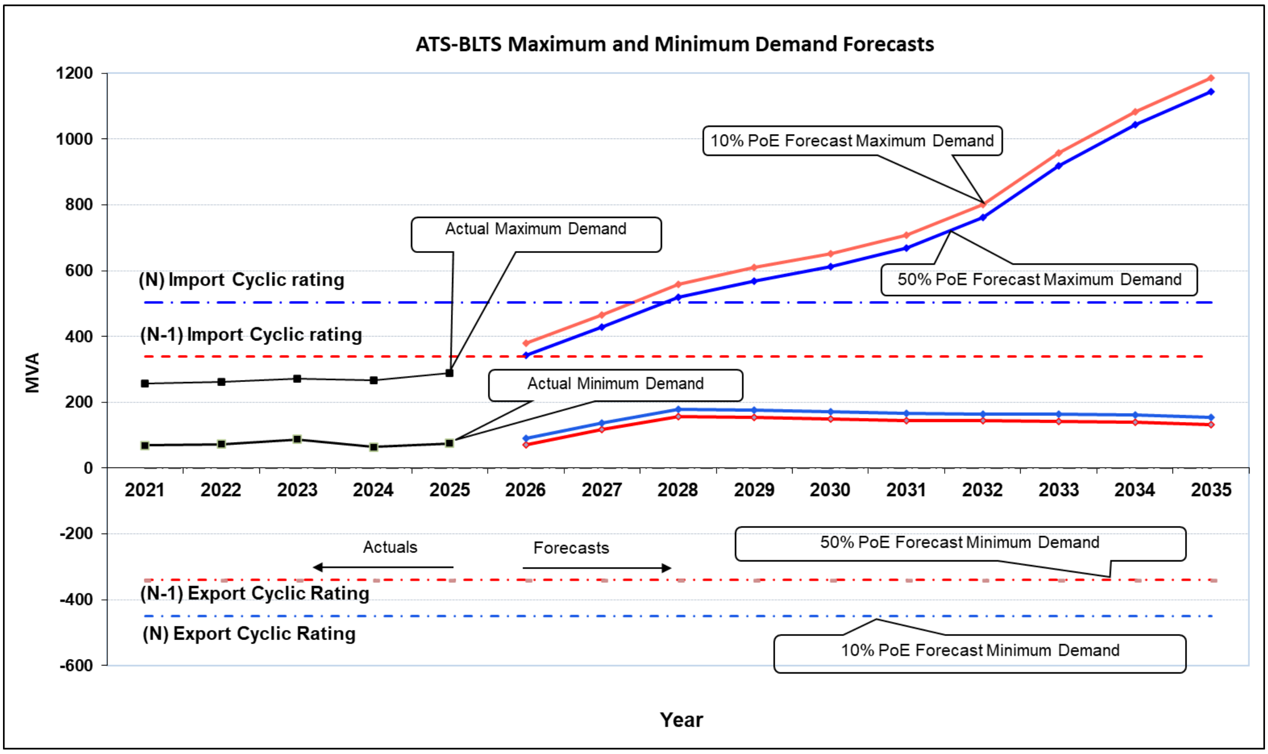
The load characteristic for ATS/BLTS substation is of a mixed nature, consisting of residential and industrial customers. The maximum demand on the entire ATS/BLTS 66 kV network reached 279.3 MW (288.9 MVA) in summer 2025.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecast together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at 40°C ambient temperature. It is noted that a temporary 66 kV supply was established recently at BLTS. At present, there is insufficient data available to enable the impact of the new temporary 66 kV supply to be considered in the forecast.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

It is expected that there will be sufficient export capacity at ATS-BLTS to accommodate all embedded generation output over the ten-year planning horizon.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



It is estimated that:

- For 8 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

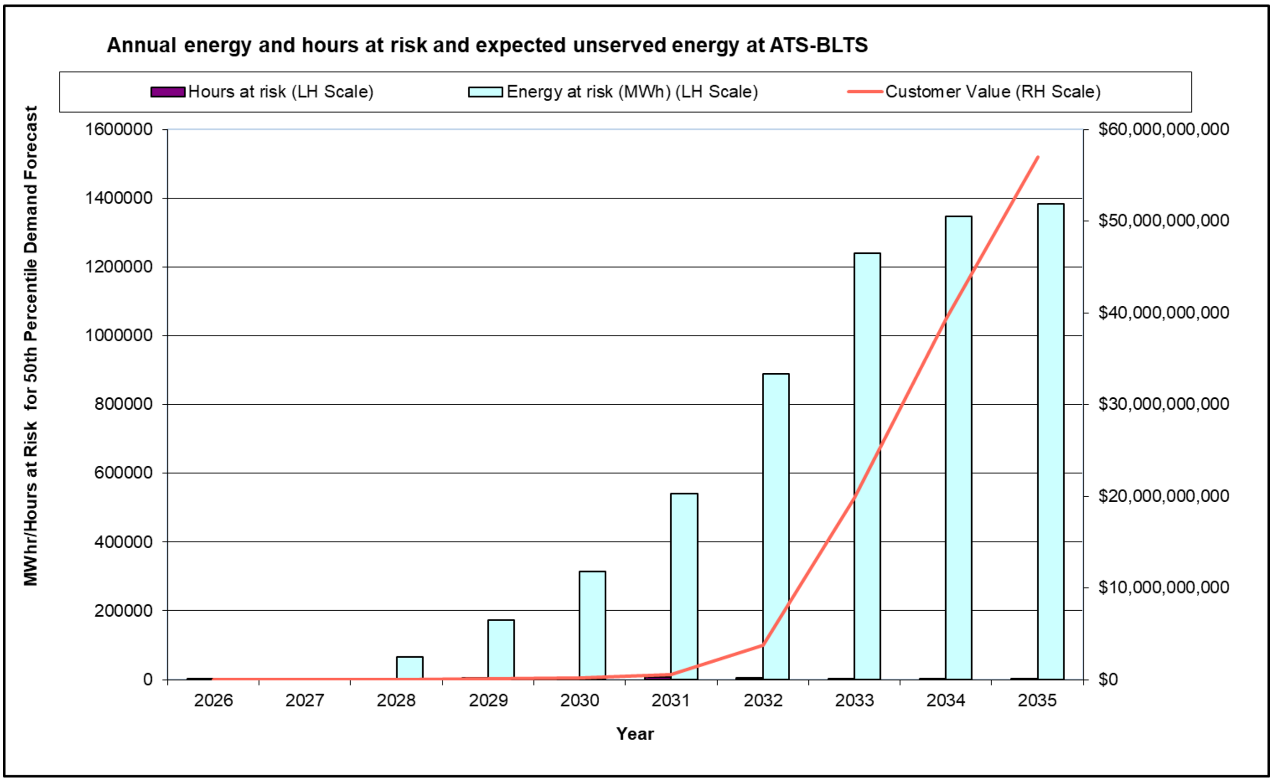
- For 8 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

Due to new major load customers which are expected to have steady load uptake over the next ten-years, and residential developments in Bacchus Marsh and Laverton North, ATS-BLTS is forecasted to exhibit strong load growth.

The graph above shows that from 2026 there is insufficient capacity to supply the forecast maximum demand at the 10th and 50th percentile temperature at ATS-BLTS 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 maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $36,588 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2028 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	66,259	$2,424 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	452	$17 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	128,641	$4,743 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	1,101	$40 million
70/30 weighted expected unserved energy value (see below)	**646.3**	**$23.7 million**

Under the probabilistic planning approach[45], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 5.4) to determine the

[45] See section 3.

expected unserved energy cost in a year due to a major transformer outage[46]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[47]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2028 is $23.7 million.

Possible Impact on Customers

System Normal Condition (Both transformers in service)

Applying the 10th percentile maximum demand forecasts, there will be insufficient capacity at ATS-BLTS to meet maximum demand from 2027 under system normal condition.

N-1 System Condition

If one of the 150 MVA 220/66 kV transformers at ATS-BLTS is taken offline during peak loading times and the N-1 station import rating is exceeded, the OSSCA[48] automatic load shedding scheme which is operated by AusNet Transmission Group's TOC[49] 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 to alleviate the emerging network import constraint:

1. Install additional transformation capacity and reconfigure 66 kV exits at ATS or BLTS, at an estimated indicative capital cost of $35 million (equating to a total annual cost of approximately $2.7 million). This would result in the station being configured so that four transformers provide capacity to the ATS/BLTS system. Given the forecasts of expected unserved energy, the installation of an additional transformer would be economically justified by 2028.

2. If the non-committed block loads identified in the demand forecast are to proceed, additional 220/66 kV transformation capacity will be required to accommodate the additional load. In such a scenario, the network option would be to construct a new 66 kV bus by installing 3 x 225 MVA 220/66 kV transformers in addition to option 1 above.

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

46 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

47 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

48 Overload Shedding Scheme of Connection Asset.

49 Transmission Operation Centre

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 or BLTS 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-BLTS to alleviate import constraints, it is proposed to install additional transformation capacity and to reconfigure 66 kV exits at ATS-BLTS system. The estimated indicative capital cost of this work is $35 million (equating to a total annual cost of approximately $2.7 million).

On the basis of the present maximum demand forecasts and VCR estimates, the installation of an additional transformer and the 66 kV exit reconfiguration works at BLTS by 2028 would be economically justified. As a temporary measure, the expected load at risk will be managed by load transfers to ATS West and DPTS.

Powercor and Jemena commenced a Regulatory Investment Test for Transmission (RIT-T) by publishing a Project Specification Consultation Report (PSCR) in September 2025 to identify feasible solutions to address the immediate capacity constraints at ATS-BLTS. The next stage report of the RIT-T, that is, the Project Assessment Draft Report (PADR), is expected to be published during the first quarter of 2026.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

The tables on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

Altona - Brooklyn Terminal Station
Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: Powercor (56%) and Jemena (44%)

	MVA	
Nameplate rating with all plant in service	450	via 3 transformers (summer)
Summer N-1 Station Import Rating:	340	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	366	
Summer N-1 Station Export Rating:	300	[See Note 7]
Winter N-1 Station Export Rating:	300	[See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	342.2	429.3	519.9	568.8	611.5	668.9	761.1	918.5	1043.7	1144.6
50th percentile Winter Maximum Demand (MVA)	357.3	450.8	521.7	573.5	623.4	685.8	783.3	946.2	1075.6	1181.2
10th percentile Summer Maximum Demand (MVA)	379.6	466.2	559.4	610.0	651.1	708.0	800.5	958.5	1084.1	1185.0
10th percentile Winter Maximum Demand (MVA)	379.0	472.8	544.2	595.9	645.4	707.9	805.5	968.9	1098.0	1203.4
N-1 energy at risk at 50% percentile demand (MWh)	0.5	3649.5	66258.5	172151.6	314396.2	540157.3	888259.4	1239871.6	1346965.0	1384699.6
N-1 hours at risk at 50th percentile demand (hours)	0.3	192.5	2108.5	3809.0	5212.0	6251.0	5754.8	2928.3	1418.8	763.0
N-1 energy at risk at 10% percentile demand (MWh)	190.3	13804.7	129641.1	270399.3	428891.9	658010.3	978366.2	1273831.4	1360536.1	1391068.3
N-1 hours at risk at 10th percentile demand (hours)	16.8	640.3	3176.5	4776.0	5821.5	6284.0	5224.8	2474.8	1183.0	640.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	24.20	451.55	1554.19	4206.32	15847.72	102329.31	541132.48	1074462.07	1557630.82
Expected Unserved Energy at 10th percentile demand (MWh)	1.26	91.53	1100.60	3483.75	9139.68	33813.34	161425.01	664264.74	1218913.32	1708851.40
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.89M	$16.52M	$56.86M	$153.90M	$579.83M	$3744.01M	$19798.88M	$39312.27M	$56990.37M
Expected Unserved Energy value at 10th percentile demand	$0.05M	$3.35M	$40.27M	$127.46M	$334.40M	$1237.16M	$5906.20M	$24304.02M	$44597.43M	$62523.21M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.01M	$1.62M	$23.65M	$78.04M	$208.05M	$777.03M	$4392.67M	$21150.42M	$40897.81M	$58650.23M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	72.2	117.6	156.8	153.8	149.0	145.4	143.5	142.9	139.7	133.3
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:
1. “N-1” means station output capability rating with outage of one transformer. The summer 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

ALTONA WEST TERMINAL STATION (ATS West) 66 kV

Altona Terminal Station 66 kV presently 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).

Embedded generation

A total of 177 MW capacity of embedded generation is installed on the Powercor distribution system connected to at ATS West. It consists of:

- 20 MW of large-scale embedded generation; and
- 157 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

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 98,461 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 load forecast and risk assessment.

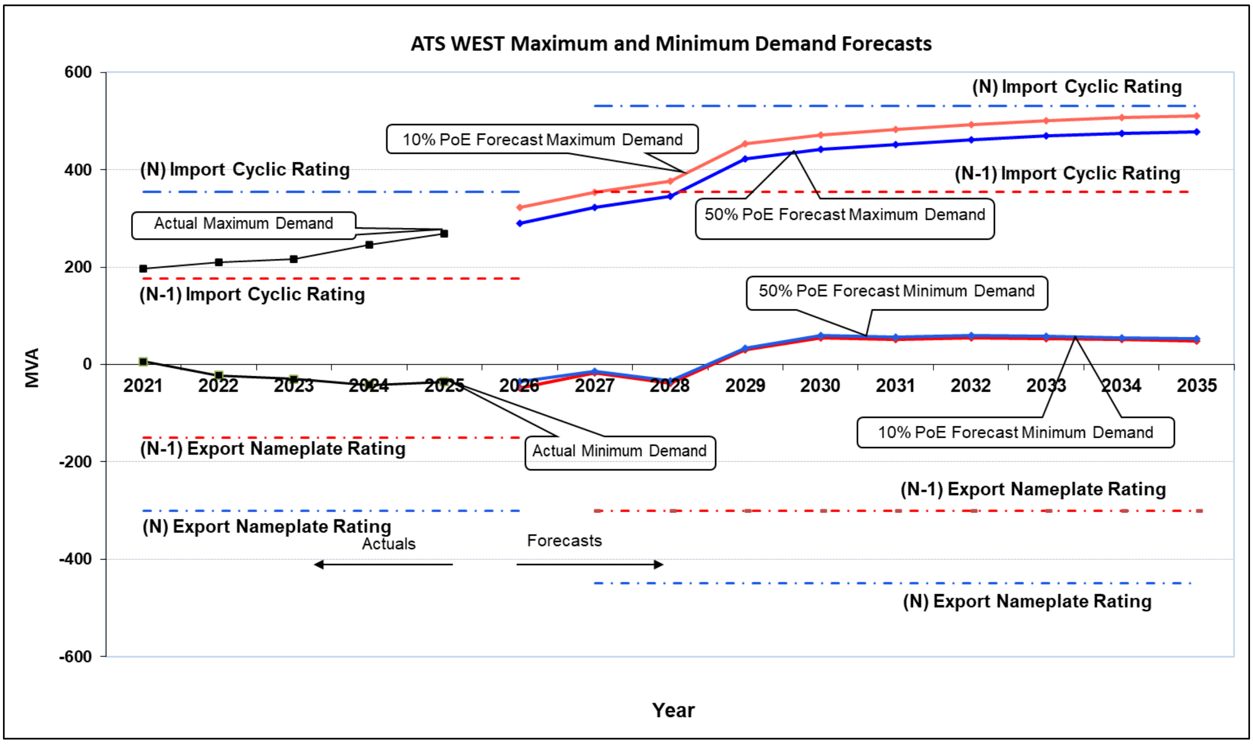
ATS West is a summer peaking station, and its maximum demand reached 259.2 MW (269.5 MVA) in summer 2025.

The graph below shows the 10th and 50th percentile maximum and minimum demand forecasts together with the stations operational “N” import and export ratings (all transformers in service) and the “N-1” import and export ratings. Note export ratings are nameplate ratings. There was a reduction in the 2021 actual MD due to transfers of approximately 30 MW from the heavily loaded LV and WBE zone substations (supplied by ATS West) to Deer Park Terminal Station (DPTS).

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal rating for export as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

Load growth at ATS West is expected to remain strong due to high population growth and increasing commercial and industrial customer connections.



It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of maximum demand is 0.96.

In relation to minimum demand, it is estimated that:

- For 4 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

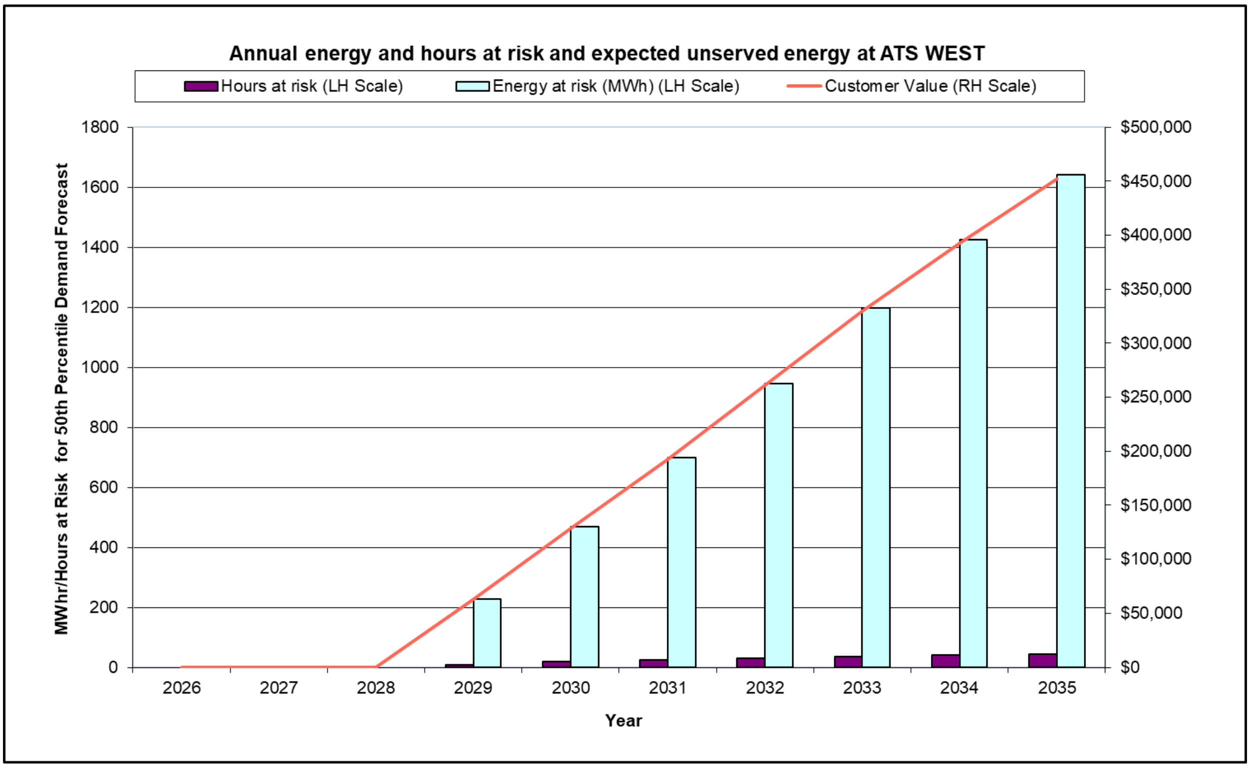
The "N" import rating on the chart indicates the maximum load that can be supplied from ATS West with all transformers in service. The "N-1" import rating on the chart is the load that can be supplied from ATS West with one 150 MVA transformer out of service.

A new transformer with a nameplate rating of 150 MVA is expected to be installed and in service from Q4 2026 at ATS West. This is reflected in the graph above, with the (N) cyclic rating increasing from 2027.

The graph above shows that there is insufficient import capacity to supply the forecast maximum demand at the 10th and 50th percentile at ATS West from 2027 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 maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $41,573 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2035 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	1,641	$68 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	10.9	$0.45 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	2,707	$113 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	18.0	$0.75 million
70/30 weighted expected unserved energy value (see below)	**13.0**	**$0.54 million**

Under the probabilistic planning approach[50], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 5.4) to determine the expected unserved energy cost in a year due to a major transformer outage[51]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying a weight of 0.7 and 0.3 to the

50 See section 3.

51 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

50th and 10th percentile expected unserved energy estimates respectively[52]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $0.54 million.

Possible Impact on Customers

If one of the 150 MVA 220/66 kV transformers at ATS West is taken offline during peak loading times and the N-1 station rating is exceeded, the OSSCA[53] automatic load shedding scheme, which is operated by AusNet Transmission Group's TOC[54], 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 import 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 DPTS terminal stations in the event of a transformer failure at ATS West total 7.5 MVA in summer 2025/26.

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 network import constraint:

1. Install additional transformation capacity and reconfigure 66 kV exits at ATS, at an estimated indicative capital cost of $35 million (equating to a total annual cost of approximately $2.7 million). This would result in the station being configured so that four transformers are supplying the ATS West load (the fourth will be configured as normally open), and one transformer will continue to provide capacity to the ATS/BLTS system.

2. 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.

3. 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 to alleviate import constraints, it is proposed to install additional transformation capacity and to reconfigure 66 kV exits at ATS. The estimated indicative capital cost of this work is $35 million (equating to a total annual cost of approximately $2.7 million).

On the basis of the present maximum demand forecasts and VCR estimates, the installation of an additional transformer and the 66 kV exit reconfiguration works at ATS would be expected to

52 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

53 Overload Shedding Scheme of Connection Asset.

54 Transmission Operation Centre

be economically justified by around 2029. As a temporary measure, the expected load at risk will be managed by the load transfers to ATS-BLTS and DPTS.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

The tables on the following pages provide more detailed data on the station rating, demand forecasts, and import and export constraints.

Altona West Terminal Station
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

	MVA
Nameplate rating with all plant in service	300 until Q4 2026 via 2 transformers (summer), then 450 via 3 transformers
Summer N-1 Station Import Rating:	177 until Q4 2026, then 354 [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	190 until Q4 2026, then 380
Summer N-1 Station Export Rating:	150 until Q4 2026, then 300 [See Note 7]
Winter N-1 Station Export Rating:	150 until Q6 2026, then 300 [See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	290.7	322.6	345.8	422.2	442.0	452.7	461.8	469.3	474.3	478.1
50th percentile Winter Maximum Demand (MVA)	250.9	311.0	338.4	402.3	417.7	436.9	452.5	464.9	475.6	485.3
10th percentile Summer Maximum Demand (MVA)	322.1	353.3	377.3	452.9	472.3	482.5	493.0	501.5	507.1	511.0
10th percentile Winter Maximum Demand (MVA)	262.1	320.4	347.4	413.0	429.0	449.1	465.1	478.2	490.1	500.0
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	228.5	467.9	697.9	946.2	1196.4	1424.3	1641.2
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	9.5	18.5	24.5	30.0	35.5	40.5	44.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	20.5	613.6	1011.1	1328.4	1714.4	2092.6	2427.1	2707.2
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	1.5	21.0	29.0	34.5	43.5	49.5	56.0	59.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	1.52	3.10	4.63	6.27	7.93	9.44	10.88
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.14	4.07	6.70	8.81	11.37	13.87	16.09	17.95
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.06M	$0.13M	$0.19M	$0.26M	$0.33M	$0.39M	$0.45M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.01M	$0.17M	$0.28M	$0.37M	$0.47M	$0.58M	$0.67M	$0.75M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.09M	$0.17M	$0.24M	$0.32M	$0.40M	$0.48M	$0.54M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	48.5	16.6	37.9	29.7	54.8	52.2	55.5	53.7	51.2	48.6
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:
1. “N-1” means station output capability rating with outage of one transformer. The summer 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.

5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

BALLARAT TERMINAL STATION (BATS) 66 kV

Ballarat Terminal Station (BATS) 66 kV consists of two 150 MVA 220/66 kV transformers and is the main source of supply for 89,186 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).

Embedded generation

A total of 347 MW capacity of embedded generation is installed on the Powercor sub-transmission and distribution systems connected to BATS. It consists of:

- 238.15 MW of large-scale embedded generation; and
- Approximately 109 MW of rooftop solar PV, including all the small-scale commercial and residential rooftop PV systems that are smaller than 1 MW.

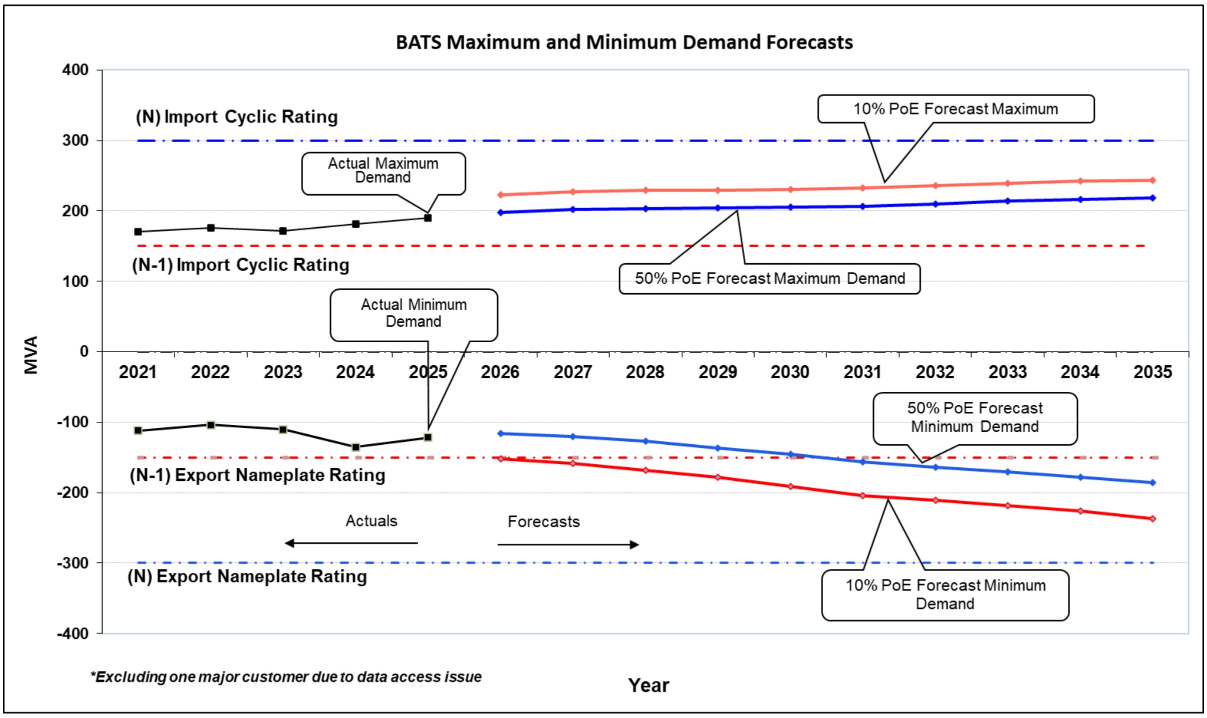
The following table lists the registered embedded generators (>5 MW) that are installed on the Powercor network connected to BATS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Challicum Hills	Existing Plant	Wind Turbine	52.5
Chepstowe Wind Farm - VIC	Existing Plant	Wind Turbine	6.15
Yaloak South Wind Farm	Existing Plant	Wind Turbine	28.7
Maroona Wind Farm	Existing Plant	Wind Turbine	6.9
Yendon Wind Farm	Existing Plant	Wind Turbine	144.4

Magnitude, probability and impact of constraints

The maximum demand at the station reached 188.1 MW (190.6 MVA) in summer 2025. The minimum demand at BATS reached -121.3 MW (-121.4 MVA) in November 2024.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" cyclic import and nameplate export ratings (all transformers in service) and the "N-1" cyclic import and nameplate export ratings and the cyclic ratings at 40°C ambient temperature. It is noted that at present, there is insufficient data available to enable the impact of the BATS BESS to be considered in the forecast.



The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown above therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of maximum demand is 0.99.

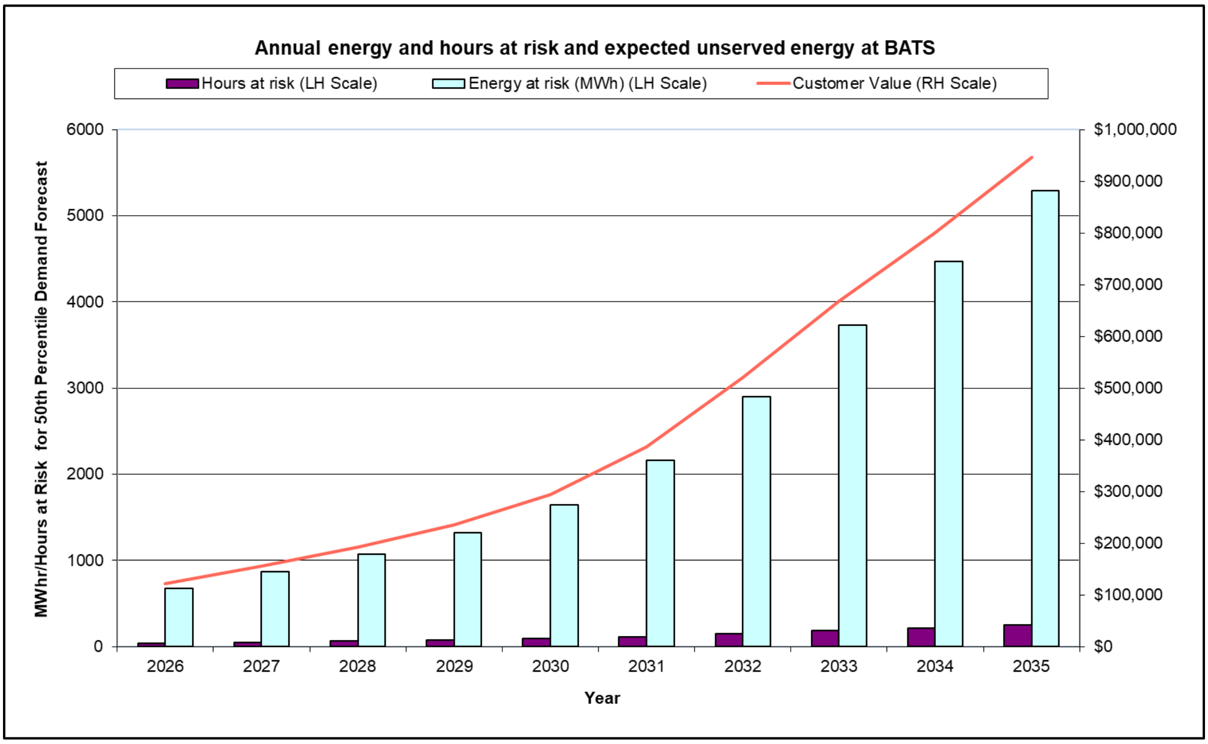
In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of peak minimum demand is 0.99.

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

50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $40,478 per MWh.



Key statistics relating to energy at risk and expected unserved energy for the year 2035 under N-1 outage conditions are summarised in the table below. Note: one major customer has been excluded due to data access issues.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	255	$214 million
Expected unserved energy at 50th percentile maximum demand	23.4	$0.95 million
Energy at risk, at 10th percentile maximum demand forecast	8,462	$342 million
Expected unserved energy at 10th percentile maximum demand	37.4	$1.51 million
70/30 weighted expected unserved energy value (see below)	**27.6**	**$1.12 million**

Under the probabilistic planning approach[55], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[56].

55 See section 3.

56 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[57]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $1.12 million.

The table headed "Export" below shows that an increasing volume of output from embedded generators connected downstream of BATS is forecast to be at risk of being curtailed over the planning period. By the end of the period in 2035, 86.5 MVA of embedded generation is at risk of curtailment for the loss of one transformer at BATS. This equates to 1,077 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 4.8 MWh, which is immaterial from a transmission connection planning perspective.

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 network import constraint:

1. Installation of a third 220/66 kV transformer (150 MVA) at BATS at an indicative capital cost of $35 million.

2. Demand reduction: There is an opportunity to develop several 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.

3. Embedded generation: The existing embedded generation that generates into the 66 kV infrastructure ex-BATS with a total capacity of 340 MW may help to supply the loads in the BATS supply area and may defer the need for any capacity augmentation within the forecast period.

4. The connection of additional large, embedded generation to the BATS 66 kV infrastructure may lead to an increased risk of terminal station transformers overloading due to reverse power flows. In these circumstances generation runback scheme(s) will be initiated.

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 to alleviate import constraints, it is proposed to:

1. Install a third 220/66 kV transformer (150 MVA) at BATS at an indicative capital cost of $35 million. This equates to a total annual cost of approximately $2.7 million per annum. On the basis of the medium economic growth scenario and both 50th and 10th percentile

[57] AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

weather probability, the transformer would not be expected to be economically justified in the forecast period.

2. As a temporary measure, maintain contingency plans to transfer load quickly to the Horsham Terminal Station (HOTS) and Brooklyn Terminal Station (BLTS 66) by the use of the 66 kV tie lines that run from BATS to HOTS and BATS to BLTS 66 in the event of an unplanned outage of one transformer at BATS under critical loading conditions. This load transfer is in the order of 20 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.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

Ballarat Terminal Station
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

	MVA	
Normal cyclic rating with all plant in service	300	via 2 transformers (summer)
Summer N-1 Station Import Rating:	150	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	150	
Summer N-1 Station Export Rating:	150	[See Note 7]
Winter N-1 Station Export Rating:	150	[See Note 7]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	177.0	186.0	193.3	200.7	204.1	206.3	209.1	213.4	218.7	221.1
50th percentile Winter Maximum Demand (MVA)	184.7	190.2	201.0	206.5	209.7	211.8	215.6	220.9	225.6	228.2
10th percentile Summer Maximum Demand (MVA)	201.8	209.2	216.3	224.5	228.0	230.1	233.3	238.0	243.7	246.0
10th percentile Winter Maximum Demand (MVA)	196.4	201.6	212.8	218.6	221.6	223.8	227.5	233.1	238.2	240.9
N-1 energy at risk at 50% percentile demand (MWh)	0.0	1.5	11.3	31.9	47.1	59.2	78.6	121.2	197.2	251.8
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.5	2.0	4.0	5.5	6.0	7.0	11.5	20.0	26.5
N-1 energy at risk at 10% percentile demand (MWh)	35.8	65.8	114.4	208.9	271.1	320.0	415.9	601.6	861.7	1011.1
N-1 hours at risk at 10th percentile demand (hours)	3.5	4.5	9.0	17.5	21.5	27.0	33.5	47.5	61.0	70.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.01	0.05	0.14	0.20	0.26	0.34	0.53	0.85	1.09
Expected Unserved Energy at 10th percentile demand (MWh)	0.15	0.29	0.50	0.91	1.17	1.39	1.80	2.61	3.73	4.38
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M	$0.01M	$0.01M	$0.02M	$0.04M	$0.05M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.01M	$0.02M	$0.04M	$0.05M	$0.06M	$0.08M	$0.11M	$0.16M	$0.19M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.01M	$0.02M	$0.02M	$0.03M	$0.03M	$0.05M	$0.08M	$0.09M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	147.2	148.5	155.3	161.5	173.8	187.5	205.4	222.6	242.1	260.8
Maximum generation at risk under N-1 (MVA)	0.0	0.0	5.3	11.5	23.8	37.5	55.4	72.6	92.1	110.8
N-1 energy curtailment (MWh)	0.0	0.0	6.0	20.2	105.8	279.5	673.6	1332.3	2461.5	3973.5
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.1	0.5	1.2	2.9	5.8	10.7	17.2

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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).
7. Station export rating is determined based on transformer nameplate rating. It has not factored any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

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 30,730 customers in Bendigo and the surrounding area. The station supply area includes Marong, Newbridge and Lockwood.

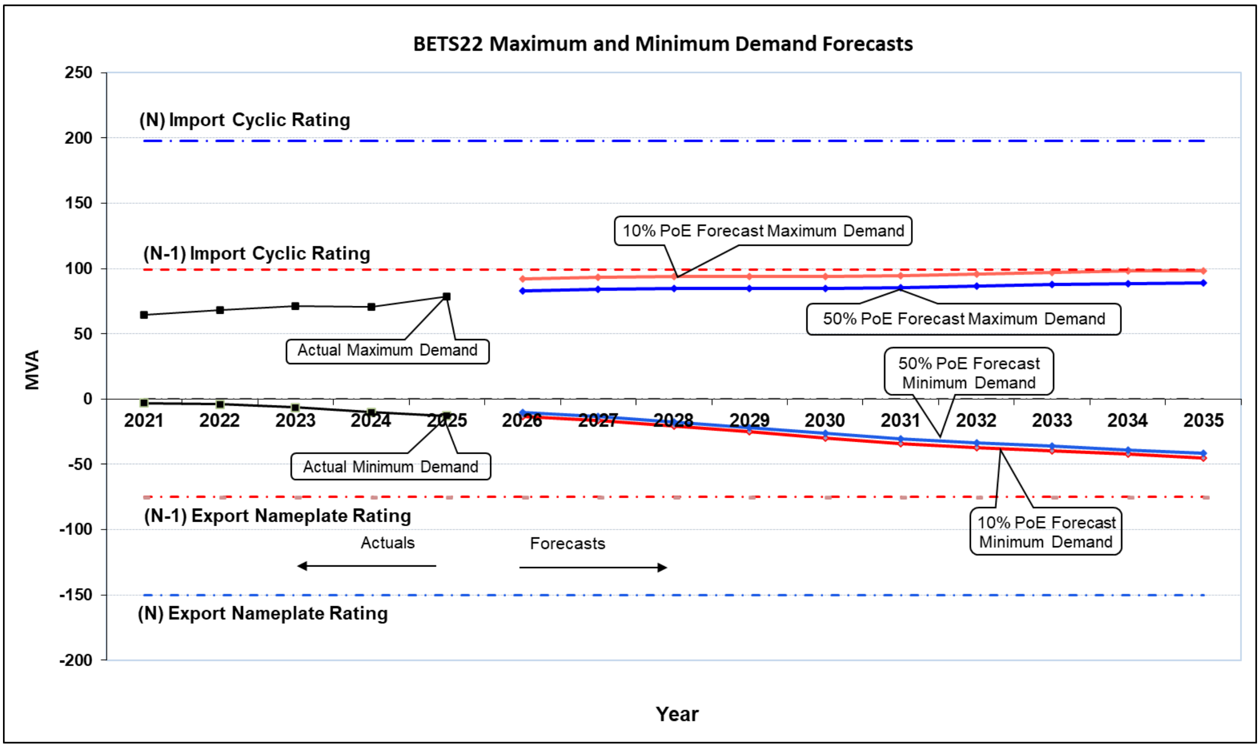
Embedded generation

About 50 MW of rooftop solar PV is installed on the Powercor distribution system connected to BETS 22 kV. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

Magnitude, probability and impact of constraints

BETS 22 kV maximum demand is summer peaking. Growth in summer maximum demand on the 22 kV network at BETS has averaged around 0.1 MVA (+0.6%) per annum over the last 5 years. The maximum demand for the 22 kV network now on the station reached 78.9 MW (78.9 MVA) in summer 2025.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export cyclic ratings at 40°C ambient temperature. Note, export ratings are nameplate ratings.



The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown above therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

It is estimated that:

- For 6 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of maximum demand is 0.99.

In relation to minimum demand, it is estimated that:

- For 4 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

The above graph shows that there is sufficient capacity at the station to supply all expected maximum demand at the 50th and 10th percentile temperatures until 2035, even with one transformer out of service. Therefore, the need for augmentation or other corrective action to alleviate import constraints is not expected to arise over the next ten years.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

BENDIGO TERMINAL STATION (BETS) 66 kV

Background

Bendigo Terminal Station (BETS) 66 kV consists of one 150 MVA 220/66 kV transformer 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 63,558 customers in Bendigo and the surrounding area as well as for Inglewood 66 kV Regulator and Kurting 66 kV Regulator. The station supply area includes Bendigo CBD, Eaglehawk, Charlton, St. Arnaud, Maryborough and Castlemaine.

Embedded generation

A total of 232 MW capacity of embedded generation is installed or proposed to be on the Powercor sub-transmission and distribution systems connected to BETS 66kV. It consists of:

- 122 MW of large-scale embedded generation; and
- 110 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the registered embedded generators (>5MW) that are installed or proposed to be installed on the Powercor network connected to BETS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Coonooer Bridge Wind Farm	Existing Plant	Wind Turbine	19.8
Yawong Wind Farm	Existing Plant	Wind Turbine	7.2
Derby Solar Farm	Proposed	Solar Farm	95

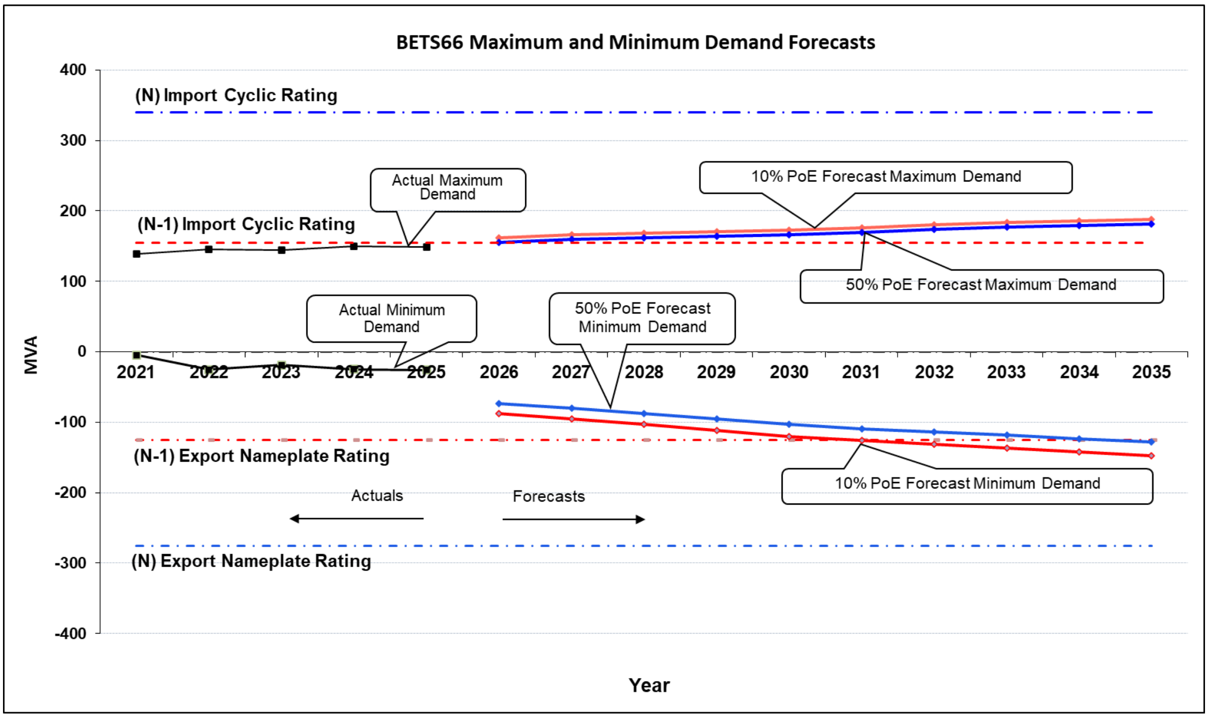
Magnitude, probability and impact of constraints

Growth in summer maximum demand at BETS 66 kV has averaged around -3.7 MVA (-2.0%) per annum over the last 5 years. The peak demand on the station reached 146.2 MW (147.4 MVA) in summer 2025.

BETS 66 kV maximum demand is summer peaking. The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at 40°C ambient temperatures.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.

- The station load power factor at time of maximum demand is 0.99.

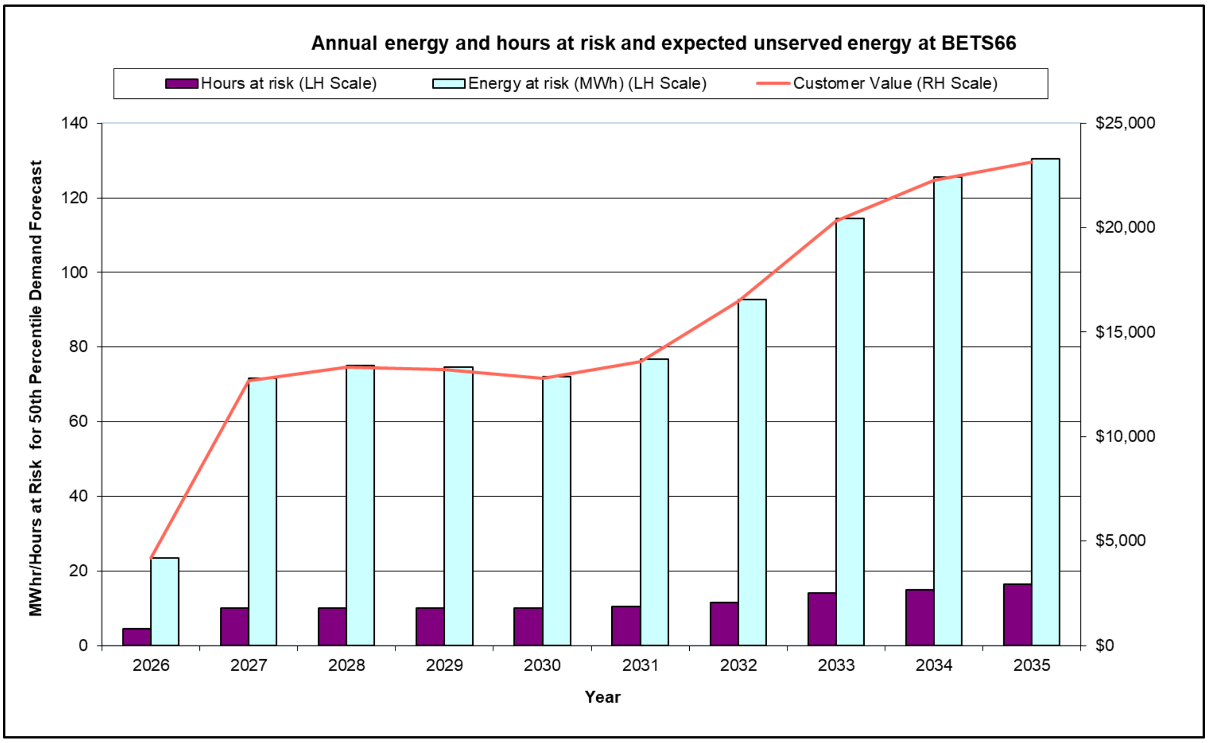
In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.

- The station load power factor at the time of minimum demand is 0.88.

The (N) rating on the chart indicates the maximum demand that can be supplied from BETS 66 kV 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 maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $40,147 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2035 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	130.5	$5.2 million
Expected unserved energy at 50th percentile maximum demand	0.6	$23,151
Energy at risk, at 10th percentile maximum demand forecast	402.9	$16.1 million
Expected unserved energy at 10th percentile maximum demand	1.8	$71,493
70/30 weighted expected unserved energy value (see below)	**0.94**	**$0.04 million**

Under the probabilistic planning approach[58], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[59]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[60].

58 See section 3.

59 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

60 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $0.04 million.

The table headed "Export" below shows that an increasing volume of output from embedded generators connected downstream of BETS is forecast to be at risk of being curtailed over the planning period. From 2030, at the 10th percentile minimum demand forecast, there is expected to be insufficient export capability to enable all embedded generation to be exported, under an N-1 condition. By the end of the period in 2035, 155 MVA of embedded generation is at risk of curtailment for the loss of one transformer at BETS. This equates to 169 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 0.7 MWh, which is immaterial from a transmission connection planning perspective.

Possible impacts of a transformer outage on customers

If one of the 230/66/22 kV transformers at BETS 66 kV is taken offline during times of maximum demand and the N-1 station import rating is exceeded, the OSSCA[61] automatic load shedding scheme which is operated by AusNet Transmission Group's TOC[62] 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 import 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 network import constraint over the next ten-year planning horizon:

1. Implement a contingency plan to transfer 12.8 MVA of load away to BETS 22 kV, KGTS, HOTS, WETS, KTS B(3,4) 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 at an estimated indicative capital cost of approximately $35 million (equating to a total annual cost of approximately $2.7 million per annum). This would result in the station being configured so that three transformers are supplying the BETS 66 kV load.
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 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 12.8 MVA of load to BETS 22 kV, KGTS, HOTS, WETS, KTS B(3,4) and SHTS will be implemented in the event of the loss of one of the BETS 220/66 kV transformers.

61 Overload Shedding Scheme of Connection Asset.

62 Transmission Operation Centre.

Given the contingency plans in place to address the forecast load at risk, it is unlikely that additional capacity can be economically justified during the forecast period. Demand reduction to reduce the load below the N-1 import rating would be the preferred option.

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 66 kV
Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station: Powercor (100%)
Normal cyclic rating with all plant in service 340 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Import Rating: 155 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 169 MVA
Summer N-1 Station Export Rating: 125 MVA [See Note 7]
Winter N-1 Station Export Rating: 125 MVA [See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	168.3	176.2	176.6	176.5	176.2	176.8	178.2	180.0	180.6	180.7
50th percentile Winter Maximum Demand (MVA)	155.8	159.8	162.0	164.0	166.2	169.7	173.6	176.9	179.1	181.2
10th percentile Summer Maximum Demand (MVA)	181.3	189.4	189.8	189.7	189.4	190.0	191.6	193.3	193.9	193.8
10th percentile Winter Maximum Demand (MVA)	162.1	166.0	168.3	170.5	172.8	176.3	180.3	183.8	186.0	187.9
N-1 energy at risk at 50% percentile demand (MWh)	23.5	71.5	75.1	74.5	72.0	76.6	92.8	114.5	125.5	130.5
N-1 hours at risk at 50th percentile demand (hours)	4.5	10.0	10.0	10.0	10.0	10.5	11.5	14.0	15.0	16.5
N-1 energy at risk at 10% percentile demand (MWh)	119.7	248.7	256.2	256.8	252.2	269.6	312.7	366.1	393.5	402.9
N-1 hours at risk at 10th percentile demand (hours)	13.5	25.5	26.0	26.5	26.5	28.0	32.0	36.0	39.5	40.5
Expected Unserved Energy at 50th percentile demand (MWh)	0.10	0.32	0.33	0.33	0.32	0.34	0.41	0.51	0.55	0.58
Expected Unserved Energy at 10th percentile demand (MWh)	0.53	1.10	1.13	1.14	1.11	1.19	1.38	1.62	1.74	1.78
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.02M	$0.02M	$0.02M	$0.02M
Expected Unserved Energy value at 10th percentile demand	$0.02M	$0.04M	$0.05M	$0.05M	$0.04M	$0.05M	$0.06M	$0.06M	$0.07M	$0.07M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.01M	$0.02M	$0.02M	$0.02M	$0.02M	$0.02M	$0.03M	$0.03M	$0.04M	$0.04M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	109.3	112.4	122.3	132.2	142.7	152.8	160.0	165.8	172.3	179.5
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	7.2	17.7	27.8	35.0	40.8	47.3	54.5
N-1 energy curtailment (MWh)	0.0	0.0	0.0	3.0	17.8	36.1	62.1	80.5	108.1	168.6
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.7

Notes:
1. “N-1” means cyclic station transformer output capability rating with outage of one transformer. 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.
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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

BROOKLYN TERMINAL STATION (BLTS) 22 kV

Brooklyn Terminal Station (BLTS) 22 kV supply area includes Altona, Brooklyn and Laverton North. The station supplies both Jemena Electricity Network (5%) and Powercor (95%) customers.

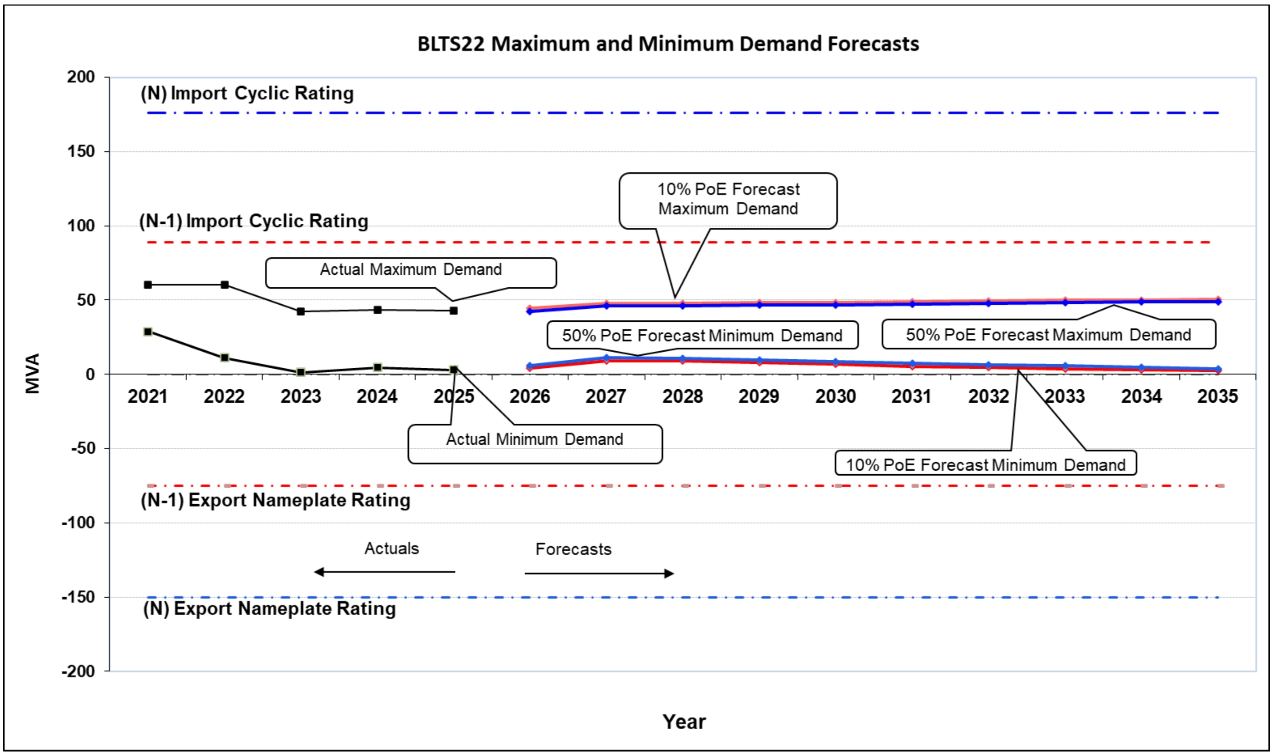
Embedded generation

About 11 MW of rooftop solar PV is installed on the Powercor distribution system connected to BLTS22. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

Magnitude, probability and impact of constraints

Brooklyn Terminal Station (BLTS) 22 kV is the main source of supply for 9,260 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. The maximum demand on the entire BLTS 22 kV network reached 40.6 MW (41.8 MVA) in summer 2025.

The graph below depicts the 10th and 50th percentile summer maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import ratings at 40°C ambient temperature and export Nameplate rating.



The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown above therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

It is estimated that:

- For 6 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.80.

The "N" import rating on the chart indicates the maximum demand that can be supplied from BLTS 22 kV Terminal Station with all transformers in service. The "N-1" import 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 import capacity at the station to supply all maximum 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 to alleviate import constraints is not expected to arise over the next ten years.

The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the forecast period.

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 (58%) and CitiPower (42%). It consists of three 75 MVA transformers operating in parallel and operates at 220/22 kV to supply a total of approximately 41,560 customers in the Brunswick, Fitzroy, Northcote, Fairfield, Essendon, Ascot Vale and Moonee Ponds areas.

Embedded Generation

About 25 MW of solar PV is installed on BTS 22 kV which includes 12 MW in the CitiPower distribution system and 13 MW in the Jemena distribution system. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

There are no embedded generators greater than 1 MW connected to BTS 22 kV.

Magnitude, probability and impact of constraints

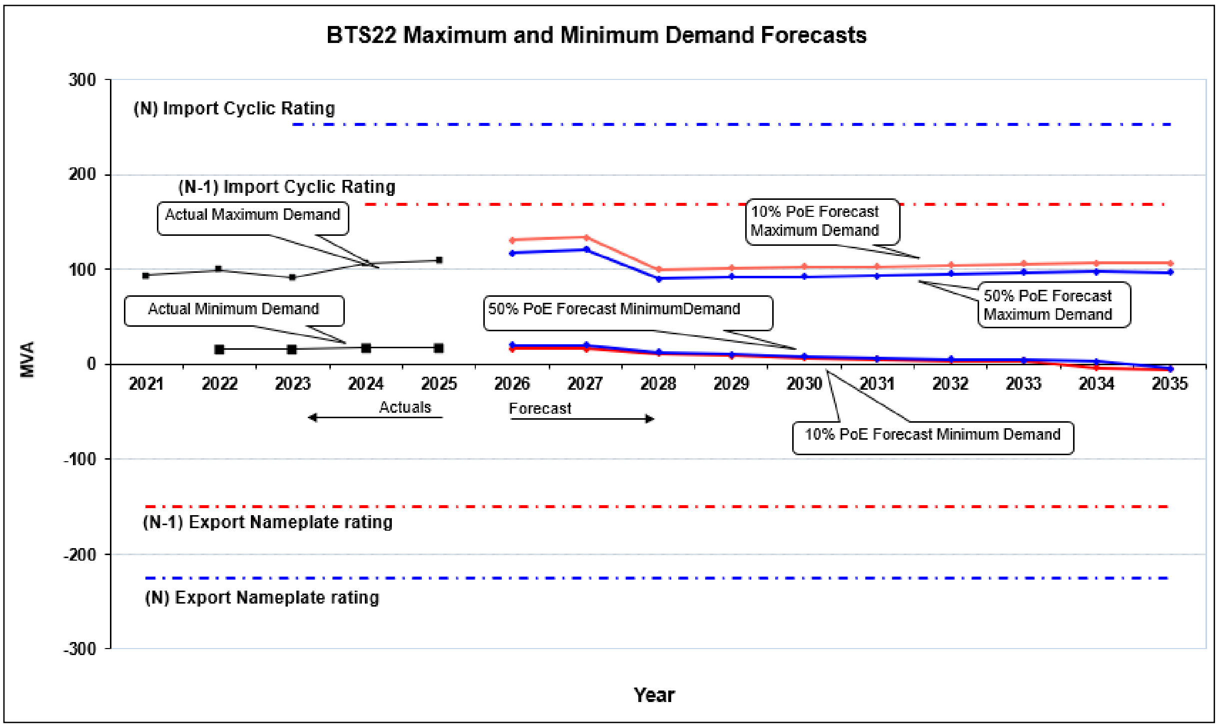
Maximum demand at BTS 22 kV occurs in winter and minimum demand at BTS 22kV occurs in summer.

The graph below shows:

- the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings, with import ratings determined at 40°C ambient temperature;
- actual station maximum demand reached 107.1 MW (108.9 MVA) in February 2025; and
- actual minimum demand reached 17.2 MW (17.2 MVA) in January 2025.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



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 transformer load power factor at the time of peak demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 24 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

The graph above shows there is sufficient station import 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 to alleviate import constraints over the next ten years.

The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the forecast period. The drop in demand forecasts in 2027 results from transferring CitiPower's BK and F zone substations (currently on the BTS 22 kV network) to nearby West Brunswick (WB) and Collingwood (CW) zone substations, which are supplied from WMTS and RTS.

Brunswick Terminal Station 22kV

Detailed Import and Export Limitation data

Distribution Businesses supplied by this station: JEN (58%), CitiPower (42%)

Station operational rating (N elements in service): 253 MVA

Summer N-1 Station Import Rating: 168 MVA

N-1 Station Export Rating: 150 MVA

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	116.9	120.6	90.1	91.8	92.5	93.7	95.3	96.7	97.2	96.8
50th percentile Winter Maximum Demand (MVA)	108.2	113.3	82.0	85.6	88.8	91.6	93.9	95.5	96.2	96.6
10th percentile Summer Maximum Demand (MVA)	130.3	134.1	99.7	101.5	102.4	103.1	104.5	106.0	106.4	106.2
10th percentile Winter Maximum Demand (MVA)	115.4	120.5	85.4	89.0	92.1	95.0	97.2	98.9	99.5	99.9
N energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N hours at risk at 50% percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N hours at risk at 10% percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	20.2	19.5	12.7	10.7	8.4	6.2	4.8	4.1	3.2	-4.1
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. 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 2.65 months. The outage probability is derived from the reliability data given in Section 4.7.

5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

BRUNSWICK TERMINAL STATION 66 kV (BTS 66 kV)

Brunswick Terminal Station (BTS) 66 kV consists of 3 x 225 MVA 220/66 kV transformers. It reinforces the security of supply to the northern and inner suburbs and the Central Business District areas. It currently provides supply to 85,618 customers.

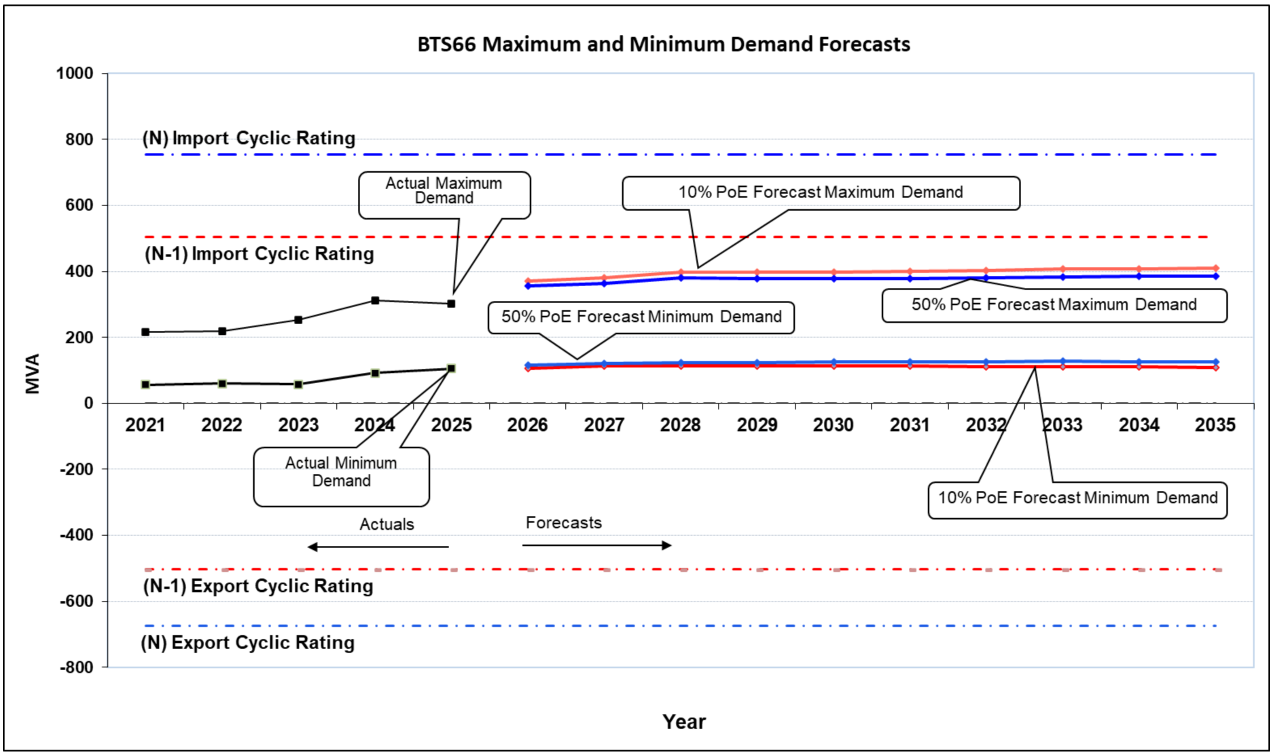
Embedded generation

About 40 MW of solar PV is installed on the CitiPower distribution system connected to BTS 66. This includes all the residential and small-commercial rooftop solar PV systems (<1 MW).

Magnitude, probability and impact of loss of load

The BTS maximum demand occurs in summer. The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at 40°C ambient temperature.

It should be noted that the ratings shown below are thermal ratings only. For some stations, export ratings (to accommodate reverse power flow) will be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the station's thermal rating. Work is underway to quantify the impacts of system limitations on station export ratings. Until that work is finalised, thermal ratings are shown.



The BTS load includes transfers from RTS 66 and WMTS 22 which occurred in September 2020 and the transfer of WB and NC from WMTS 66 that occurred in 2023. The station maximum demand reached 296.2 MW (303.3 MVA) in summer 2025.

It is estimated that:

- For 12 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.

- The station load power factor at the time of maximum demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 64 hours per year, 95% of the minimum demand is expected to be reached.

- The station load power factor at the time of minimum demand is 0.98.

BTS 66 is one of the terminal stations suppling the Melbourne CBD. In order to meet the Distribution Code of Practice requirements regarding security of supply to the Melbourne CBD, CitiPower has been undertaking works to re-configure the CBD 66 kV network to provide the required security to maintain supply from alternate supply points. This means that for an 'N-1' event in other parts of the CBD network, additional load can be switched onto BTS 66. This required additional import capacity must be reserved at the terminal station to ensure that CBD load can be supplied under any of the CBD security contingency arrangements.

The graph above shows that there is expected to be sufficient import capacity at the station to meet expected maximum demand over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action at the station to alleviate import constraints is not expected to arise over the current ten-year planning horizon.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the 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 for this area is the responsibility of both AusNet Electricity Services (64%) and United Energy (36%).

In late-2025, AusNet Transmission Group reviewed and updated the cyclic ratings of the CBTS transformers, considering the rating limitations of the HV tap changers. As a result, the “N” winter cyclic rating (15°C) was reduced to 543 MVA, down from 619 MVA, and the “N-1” winter cyclic rating (15°C) was reduced to 362 MVA, down from 413 MVA, while the summer cyclic ratings remain unchanged. Consequently, the energy-at-risk has increased due to higher demand forecasts and the reduction in the station rating (both N and N-1 risk present).

Embedded generation

A total of 416.7 MW of embedded generation capacity is installed on the distribution systems connected to CBTS, including:

- about 274.7 MW of rooftop solar PV installed on the AusNet distribution system and about 111.8 MW of rooftop solar PV installed on the UE distribution system. This includes all the residential and small commercial rooftop PV systems that are smaller than 1 MW; and
- 30.0 MW capacity of large-scale embedded generation installed on the UE distribution system connected to CBTS.

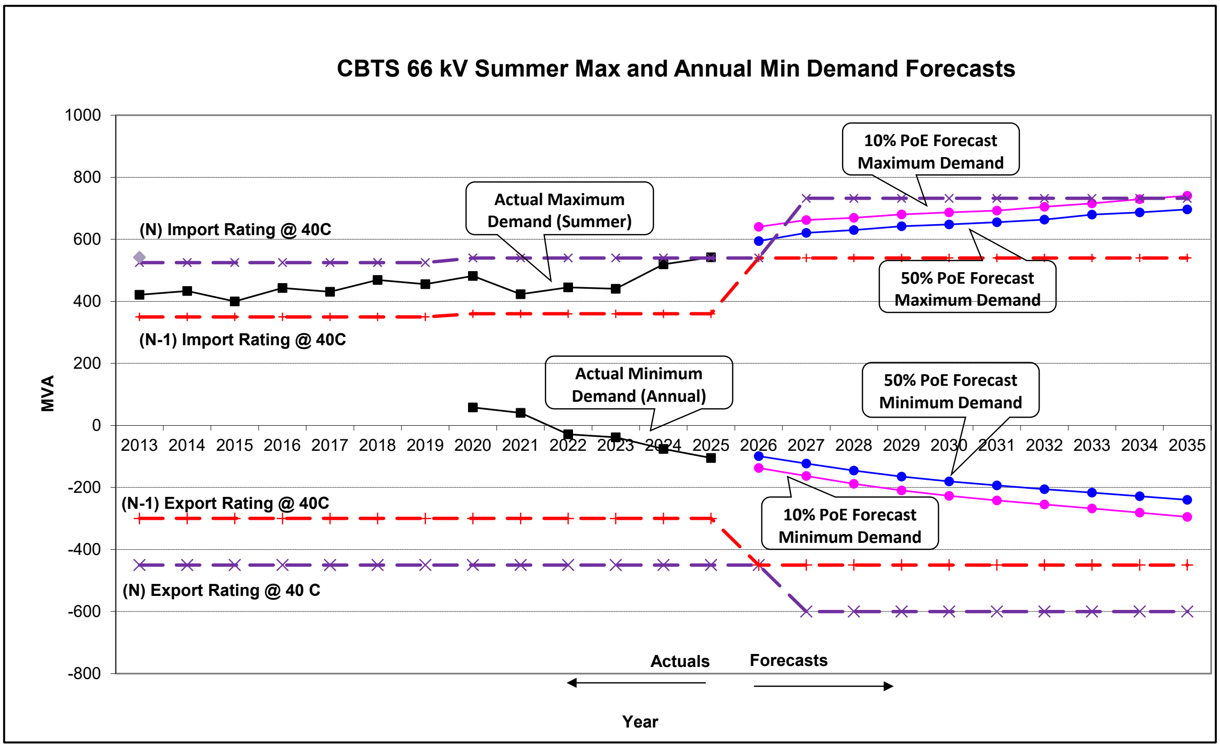
Magnitude, probability and impact of constraints

Maximum demand at CBTS 66 kV occurs in summer. The summer peak demand at CBTS 66 kV has increased by 121 MVA between 2012/13 and 2024/25, which was equivalent to an average annual growth rate of 2.4%. In 2024/25, the summer maximum demand on the station reached 524.5 MW (541.7 MVA), which is the highest annual maximum demand recorded to date.

The graph below shows the 10^{th} and 50^{th} percentile summer maximum and annual minimum demand forecasts together with the station’s expected operational “N” import and export ratings (all transformers in service) and the “N-1” import and export ratings (loss of a transformer) at 40°C ambient temperatures.

The station ratings shown in the graph reflect the connection of the CBTS fourth transformer in December 2025. This transformer will serve as a hot spare during the 2025/26 summers. Therefore, the “N-1” ratings will increase to be equal to the “N” ratings. After the 66 kV feeder re-arrangement is completed, the hot spare is planned to be connected as an in-service transformer before the 2026/27 summer, and the “N” ratings will be increased to account for four transformers. The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



The station load has a power factor of 0.968 at maximum demand in summer. Demand at CBTS 66 kV is expected to exceed 95% of the 50th percentile maximum demand for 2 hours per annum.

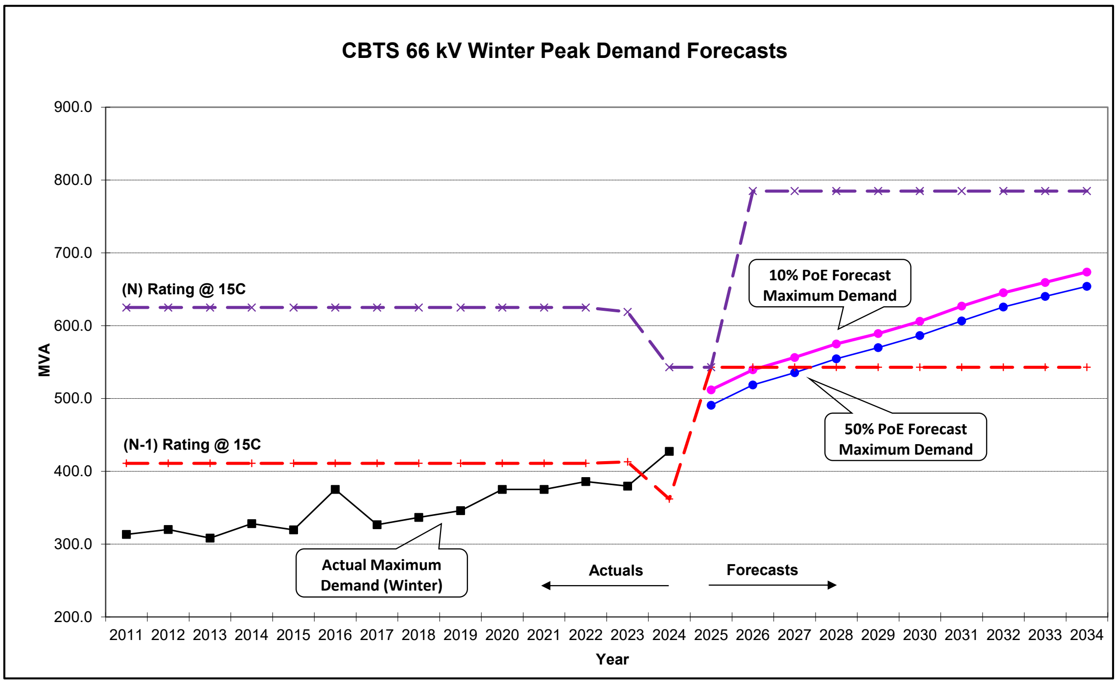
In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.99 at the time of minimum demand.

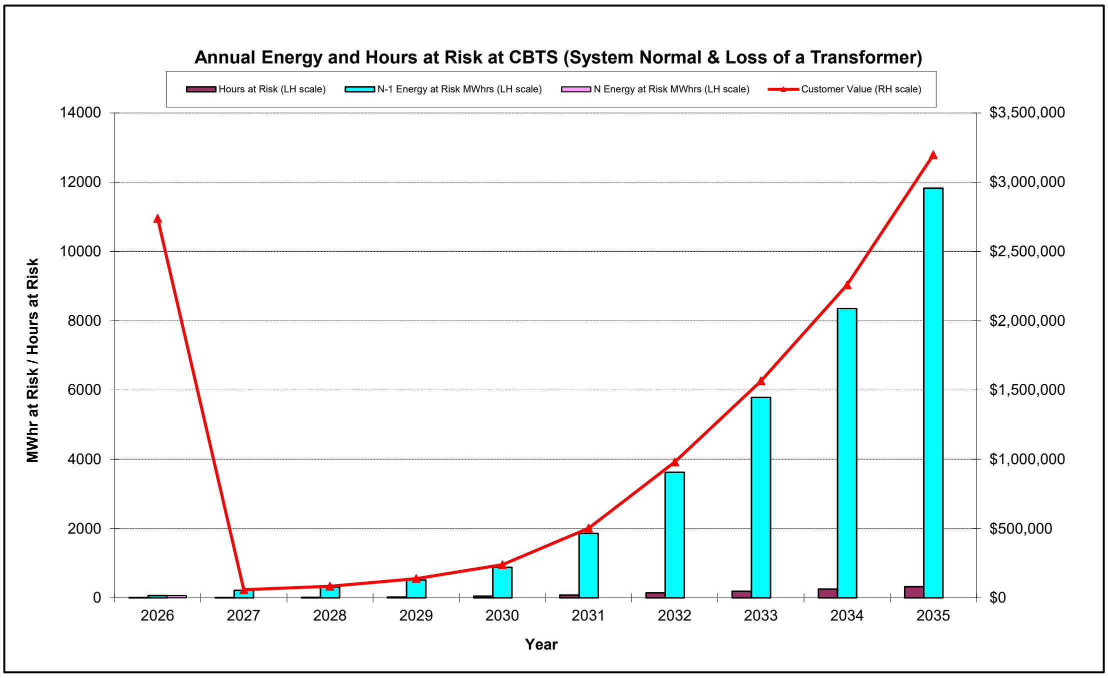
Maximum demand at CBTS 66 kV has already exceeded the “N” import rating during the past summer 2024/25 and is expected to continue increasing for the next summer, with both the 10th and 50th percentile forecasts projected to exceed the “N” import rating. As a solution, on hot summer days, when the demand cannot be supplied through the existing three transformers, DBs plan to temporarily connect the hot spare in parallel.

Minimum demand levels remained well within the station’s operational “N” and “N-1” export ratings. This trend is expected to continue under both 10th and 50th percentile minimum demand forecasts over the 10-year planning period.

The graph below shows the 10th and the 50th percentile winter maximum demand forecasts together with the station’s operational “N” and “N-1” import ratings for winter. As mentioned earlier, there has been a significant reduction in the CBTS station rating from late 2025 due to the rating limitations of the HV tap changers. The “N” winter cyclic rating (15 °C) was reduced to 543 MVA, down from 619 MVA, and the “N-1” winter cyclic rating (15 °C) was reduced to 362 MVA, down from 413 MVA. In 2024, the winter maximum demand has already exceeded the “N-1” rating and is expected to continue increasing, with both the 10th and 50th percentile forecasts projected to exceed the “N-1” import rating by 2027 and 2028, respectively.



The bar chart below depicts the energy at risk under system normal (i.e., “N” risk) and with one transformer out of service (i.e., “N-1” risk) for the 50th percentile maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the “N-1” import rating. The line graph shows the cost to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast. Since the fourth transformer will serve as a hot spare for the next summer, the “N” risk will arise and is expected to be eliminated once the 66 kV feeder re-arrangement is completed by 2026/27 summer. Therefore, there is a prominent drop in expected unserved energy (the red line) in 2027, as shown in the chart below.



Key statistics relating to energy at risk and expected unserved energy for the year 2026/27 are summarised in the table below. The VCR for CBTS is $41,612 per MWh.

	MWh	Valued at VCR
N-1 Energy at risk, at 50th percentile maximum demand forecast	216.3	$9.0 million
N Energy at risk, at 50th percentile maximum demand forecast	0.0	$0.0 million
Expected unserved energy at 50th percentile maximum demand	1.0	$0.04 million
N-1 Energy at risk, at 10th percentile maximum demand forecast	674.0	$28.0 million
N Energy at risk, at 10th percentile maximum demand forecast	0.0	$0.0 million
Expected unserved energy at 10th percentile maximum demand	3.0	$0.12 million
70/30 weighted expected unserved energy value (see below)	**1.6**	**$0.07 million**

Under the probabilistic planning approach[63], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[64]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[65]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2026/27 is $0.07 million.

Over the forecast period, there is no export generation at risk of being curtailed.

Possible impacts of a transformer outage on customers

If the N station import rating is exceeded or one of the 220/66 kV transformers at CBTS is out of service during times of maximum demand and the N-1 station import rating is exceeded, the Overload Shedding Scheme for Connection Assets (OSSCA)[66] which is operated by AusNet Transmission Group's TOC[67] 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 296 MVA of load (i.e., the OSSCA Group 1 load), affecting up to 124,000 customers. 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

63 See section 3.1.

64 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

65 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

66 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.

67 Transmission Operations Centre

and AusNet Electricity Services' operational procedures after the operation of the OSSCA scheme.

Feasible options for alleviation of constraints

The following options are technically feasible actions to mitigate the risk of supply interruption and/or to alleviate the emerging network import 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 both 22 kV distribution and 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 22 kV distribution network is capable of transferring approximately 35 MVA out of CBTS. Where required, such as if a 10^{th} percentile temperature day was anticipated, the 22 kV load transfers would also be utilised to manage system normal loading to within the terminal station's limits until augmentation is economically justified and implemented. The emergency 66 kV ties can be in operation within 2 hours following a contingency event and have a combined capability to transfer up to 99 MVA of load out of CBTS.

2. Establish a new 220/66 kV terminal station: AusNet Electricity Services expects that a new terminal station in the Narre Warren 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 address 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 4^{th} 220/66 kV transformer at Cranbourne Terminal Station: The site has provision for a 4^{th} transformer and implementing this option is relatively straight forward, although 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 0.97 lagging in summer. Two 50 MVAR 66 kV capacitor banks will help to reduce the net MVA supplied by the transformers by approximately 16 MVA and could defer a network augmentation by approximately one year.

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 to 25 MW, connected to the CBTS 66 kV bus, could defer the need for augmentation by approximately two years.

Preferred network option for alleviation of constraints

In 2022, AusNet Electricity Services and United Energy completed a Regulatory Investment Test for Transmission (RIT-T) to address the supply risks at CBTS[68]. Due to a material change in one of the inputs (option costs), AusNet and United Energy re-commenced the RIT-T with the Project Specification Consultation Report (PSCR)[69] being published in October 2024. The Project Assessment Draft Report (PADR) was published in June 2025. The Project Assessment Conclusions Report (PACR) was published in August 2025 completing the RIT-T process. The preferred option of the RIT-T is installation of a fourth 220/66kV 150 MVA transformer at CBTS by 2026/27.

During the 2024/25 summer, CBTS experienced a significant demand increase. The increased summer demand caused significant increase in Energy at Risk (EAR). To manage the increased EAR at CBTS, AusNet Electricity Services and United Energy decided to move one of the spare 220/66 kV 150 MVA transformers to CBTS and establish it as a hot spare for the 2025/26 summer. On hot summer days, when the demand cannot be supplied through the existing three transformers, DBs plan to temporarily connect the hot spare. After the 66 kV feeder re-arrangement is completed, the hot spare is planned to be connected as an in-service transformer before the 2026/27 summer.

In addition, the following temporary measures to cater for any "N" risk and an unplanned outage of one transformer at CBTS under critical loading conditions have been established:

- maintain emergency plans to transfer load to adjacent terminal stations via 22 kV feeders (providing 35 MVA of transfer capability) and 66 kV tie lines (providing up to 99 MVA of transfer capability within 2 hours of a contingency); and
- fine-tune the OSSCA scheme settings to minimise the impact on customers of any automatic load shedding that may take place.

There is expected to be sufficient station export capability to accommodate all embedded generation output over 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.

[68] Cranbourne Supply Area RIT-T PACR, October 2022 (unitedenergy.com.au)

[69] Cranbourne Supply Area RIT-T PSCR, October 2024 (unitedenergy.com.au)

CRANBOURNE TERMINAL STATION 66kV Loading (CBTS)
Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station: AusNet Services (64%), United Energy(36%)

	CBTS 3 Transformers	CBTS 4 Transformers	
Normal cyclic import rating with all plant in service	540 MVA	745 MVA	Summer peaking
Summer import N-1 Station Rating	360 MVA	540 MVA	[See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating	362 MVA	543 MVA	
Normal export rating with all plant in service	450 MVA	600 MVA	[See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	300 MVA	450 MVA	[See Note 7 below for interpretation of Export rating]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	594.3	621.0	630.2	642.1	647.7	655.0	663.5	679.4	686.6	696.1
50th percentile Winter Maximum Demand (MVA)	518.7	535.5	554.5	569.9	586.5	606.7	625.6	640.3	654.0	668.4
10th percentile Summer Maximum Demand (MVA)	639.9	662.0	669.4	680.0	686.7	692.2	704.5	715.6	729.4	740.4
10th percentile Winter Maximum Demand (MVA)	539.4	556.4	575.0	589.2	606.0	626.9	645.2	659.4	673.8	686.4
N - 1 energy at risk at 50th percentile demand (MWh)	65.4	216.3	310.2	513.9	883.2	1,859.7	3,626.4	5,788.0	8,352.7	11,824.3
N - 1 hours at risk at 50th percentile demand (hours)	4.7	8.5	14.1	21.1	45.7	82.2	141.2	190.0	254.5	319.8
N - 1 energy at risk at 10th percentile demand (MWh)	377.2	674.0	922.0	1,436.1	2,326.1	4,281.8	7,136.3	10,218.9	14,197.6	18,313.0
N - 1 hours at risk at 10th percentile demand (hours)	11.6	21.5	33.1	57.9	89.5	154.9	223.1	289.8	359.3	422.7
N energy at risk at 50th percentile demand (MWh)	65.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N hours at risk at 50th percentile demand (hours)	4.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N energy at risk at 10th percentile demand (MWh)	377.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
N hours at risk at 10th percentile demand (hours)	11.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Expected Unserved Energy at 50th percentile demand (MWh)	65.7	1.0	1.4	2.3	3.9	8.3	16.1	25.8	37.2	52.6
Expected Unserved Energy at 10th percentile demand (MWh)	378.8	3.0	4.1	6.4	10.4	19.1	31.8	45.5	63.2	82.0
Expected Unserved Energy value at 50th percentile demand	$2.73M	$0.04M	$0.06M	$0.10M	$0.16M	$0.34M	$0.67M	$1.07M	$1.55M	$2.19M
Expected Unserved Energy value at 10th percentile demand	$15.76M	$0.12M	$0.17M	$0.27M	$0.43M	$0.79M	$1.32M	$1.89M	$2.63M	$3.41M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$6.64M	$0.07M	$0.09M	$0.15M	$0.24M	$0.48M	$0.87M	$1.32M	$1.87M	$2.56M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	-137.0	-163.1	-187.9	-209.5	-226.8	-241.6	-255.1	-267.8	-281.5	-294.7
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

DEER PARK TERMINAL STATION (DPTS) 66 kV

Deer Park Terminal Station (DPTS) 66 kV consists of two 225 MVA 220/66 kV transformers connected into one of three existing KTS-GTS 220 kV lines and is located at the corner of Christies Road and Riding Boundary Road in Deer Park. The station supplies 118,133 Powercor customers in the areas of Sunshine, Truganina, Tarneit, Laverton North, Caroline Springs and Melton.

DPTS was commissioned for service in the fourth quarter of 2017. It has enabled the offloading of both transformer groups at KTS, thereby mitigating a significant emerging import constraint at KTS from summer 2017/18 onwards. The initial transfer to the new DPTS of SU (Sunshine) zone substation from KTS (B1,2,5) transformer group has been completed and the transfer of MLN (Melton) zone substation from KTS (B3,4) group was completed during Autumn of 2018. DPTS also supplies a nearby new zone substation, Truganina (TNA), offloading nearby LV (Laverton), LVN (Laverton North), SU and WBE (Werribee) zone substations, and augments supply to the fast-growing western suburbs of Melbourne.

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

Embedded generation

A total of 220.4 MW of embedded generation is installed on the Powercor distribution system connected to DPTS. This consists of:

- 14.4 MW of large-scale embedded generation; and
- Around 206 MW of rooftop solar PV, including all the small-commercial and residential rooftop PV systems that are smaller than 1 MW.

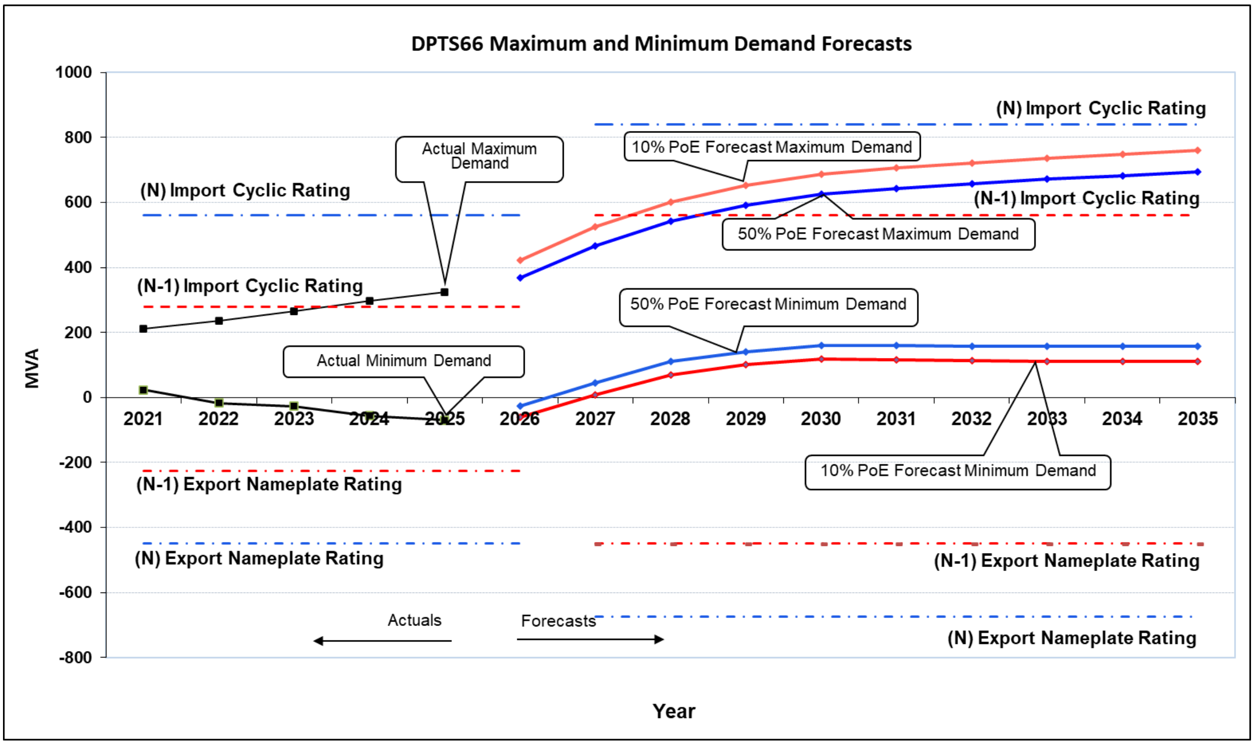
Magnitude, probability and impact of constraints

The maximum demand on the station reached 311.5 MW (324.9 MVA) in summer 2025. Maximum demand at the 10th percentile temperature is forecast to increase to 761 MVA by 2035, due to the high load growth in the western suburbs of Melbourne and additional transfers from LVN, LV and WBE zone substations.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" cyclic import and nameplate export ratings (all transformers in service) and the "N-1" cyclic import and nameplate export ratings and the cyclic ratings at 40°C ambient temperature.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



It is estimated that:

- For 2 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at time of maximum demand is 0.96.

In relation to minimum demand, it is estimated that:

- For 4 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

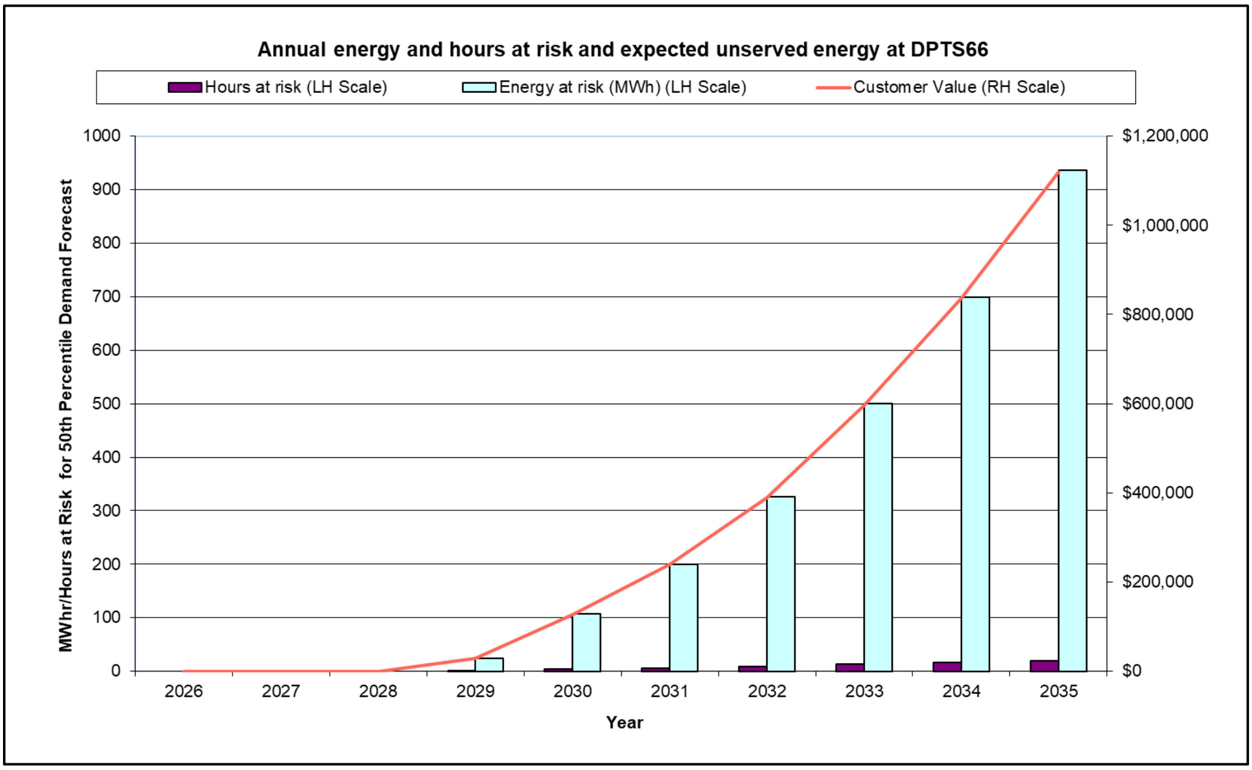
The (N) import rating on the chart indicates the maximum demand that can be supplied from DPTS with all transformers in service. The “N-1” import rating on the chart is the load that can be supplied from DPTS with one 225 MVA transformer out of service.

A new, third transformer with nameplate rating of 225 MVA will be installed and in service from 2027-28 at DPTS. This is reflected in the graph above, with the (N) cyclic rating increasing from 2027 onwards.

The graph above shows there is insufficient capacity at the station to supply all maximum demand at both 50th and 10th percentile temperature if a forced outage of a transformer occurs. Due to the installation of the third transformer from 2027 onwards, the graph above shows there is sufficient capacity at the 10th and 50th percentile temperature to supply all maximum demand with all transformers in service.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $39,855 per MWh.

At present, a spare 225 MVA transformer suitable for installation at DPTS is not available. CitiPower-Powercor have adopted the conservative assumption that a major transformer failure would be highly unlikely to be repairable, and therefore a replacement transformer would need to be procured in the event of a transformer failure. Accordingly, a major outage of a DPTS transformer is assumed to have an annual duration of 12 months.



Key statistics relating to energy at risk and expected unserved energy for 2035 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	936	$37.3 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	28	$1.1 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	2,403	$95.8 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	72	$2.9 million
70/30 weighted expected unserved energy value (see below)	**41.3**	**$1.6 million**

Under the probabilistic planning approach[70], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (1%, as explained in section 4.7) to determine the

[70] See section 3.

expected unserved energy cost in a year due to a major transformer outage[71]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of energy at risk and expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[72]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $1.6 million.

Possible Impact on Customers

System Normal Condition (Both transformers in service)

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

N-1 System Condition

If one of the 225 MVA 220/66 kV transformers at Deer Park is taken offline during times of maximum demand and the N-1 station import rating is likely to be exceeded, transfers will be undertaken to KTS to avoid overloading the remaining transformer. Possible load transfers away to ATS/BLTS and ATS West terminal stations in the event of a transformer failure at DPTS total 33.9 MVA in summer 2025/26.

Feasible option(s) 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 network import constraint:

1. Install additional transformation capacity at DPTS, at an estimated indicative capital cost of approximately $35 million (equating to a total annual cost of approximately $2.73 million per annum). This would result in the station being configured so that four transformers are supplying the DPTS load. Given the forecasts of expected unserved energy, the installation of an additional transformer would be unlikely to be economically justified before 2035.

2. 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.

3. Embedded generation, connected to the DPTS 66 kV bus, may substitute capacity augmentations.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

71 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

72 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

The tables on the following pages provide more detailed data on the station rating, demand forecasts, and import and export constraints.

Deer Park Terminal Station
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

MVA

Nameplate rating with all plant in service (summer): 450 via 2 transformers until 2027-28, then 675 via 3 transformers from 2027-28

Summer N-1 Station Import Rating: 280 until 2027-28, then 420 [See Note 1 below for interpretation of N-1]

Winter N-1 Station Import Rating: 300 until 2027-28, then 450

Summer N-1 Station Export Rating: 225 until 2027-28, then 450 [See Note 7]

Winter N-1 Station Export Rating: 225 until 2027-28, then 450 [See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	367.9	466.1	542.2	591.2	625.5	643.7	657.5	671.5	682.9	693.5
50th percentile Winter Maximum Demand (MVA)	351.3	465.9	532.7	586.5	624.3	648.7	672.4	694.9	714.6	733.2
10th percentile Summer Maximum Demand (MVA)	421.9	525.3	601.7	651.9	686.9	706.0	721.6	736.6	749.1	761.1
10th percentile Winter Maximum Demand (MVA)	384.6	498.7	566.4	620.1	657.0	681.5	707.3	730.2	749.4	768.6
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	23.5	106.6	199.8	325.5	499.7	699.2	935.9
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	1.0	4.0	5.5	9.0	12.5	16.0	19.5
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	37.7	205.7	497.1	766.6	1091.7	1499.2	1911.6	2403.2
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	1.5	6.5	11.5	17.0	22.0	28.0	33.0	41.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.71	3.20	6.00	9.77	14.99	20.98	28.08
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	1.13	6.17	14.91	23.00	32.75	44.97	57.35	72.10
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.03M	$0.13M	$0.24M	$0.39M	$0.60M	$0.84M	$1.12M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.05M	$0.25M	$0.59M	$0.92M	$1.31M	$1.79M	$2.29M	$2.87M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.01M	$0.09M	$0.27M	$0.44M	$0.66M	$0.96M	$1.27M	$1.65M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	60.5	9.4	69.3	100.7	118.7	116.4	113.5	112.2	111.1	110.9
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:
1. “N-1” means station output capability rating with outage of one transformer. The summer 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 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 an annual duration of 12 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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 2024 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

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.

Embedded generation

A total of 261 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to ERTS. It consists of:

- 231.1 MW of rooftop solar PV systems. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW; and

- 29.9 MW of large-scale embedded generation capacity from 5 units over 1 MW.

Magnitude, probability, and impact of constraints

ERTS has four 150 MVA 220/66 kV transformers and operates in a split bus arrangement. Under system normal conditions, the No.1 and No.2 transformers (B1 and B2) are operated in parallel as one group (ERTS 12) and supply the No.1 and No.2 buses. The No.3 and No.4 transformers (B3 and B4) are operated in parallel as a separate group (ERTS 34) and supply the No.3 and No.4 buses. Connection between No.1 and No.4 buses is maintained via the 1-4 bus-tie circuit breaker. The 66 kV 2-3 and 4-5 bus-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 2-3 or 4-5 bus-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 ERTS 12 group should be kept within the import capabilities of the two transformers, B1 and B2, at all times.

- Load demand on the ERTS 34 group should be kept within the import capabilities of the two transformers, B3 and B4, at all times.

- Load demand on the total station should be kept within the import capabilities of any three transformers when one transformer is out of service.

In the graphs on the following pages, the N import rating indicates the maximum demand that can be supplied 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 export ratings on the charts reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

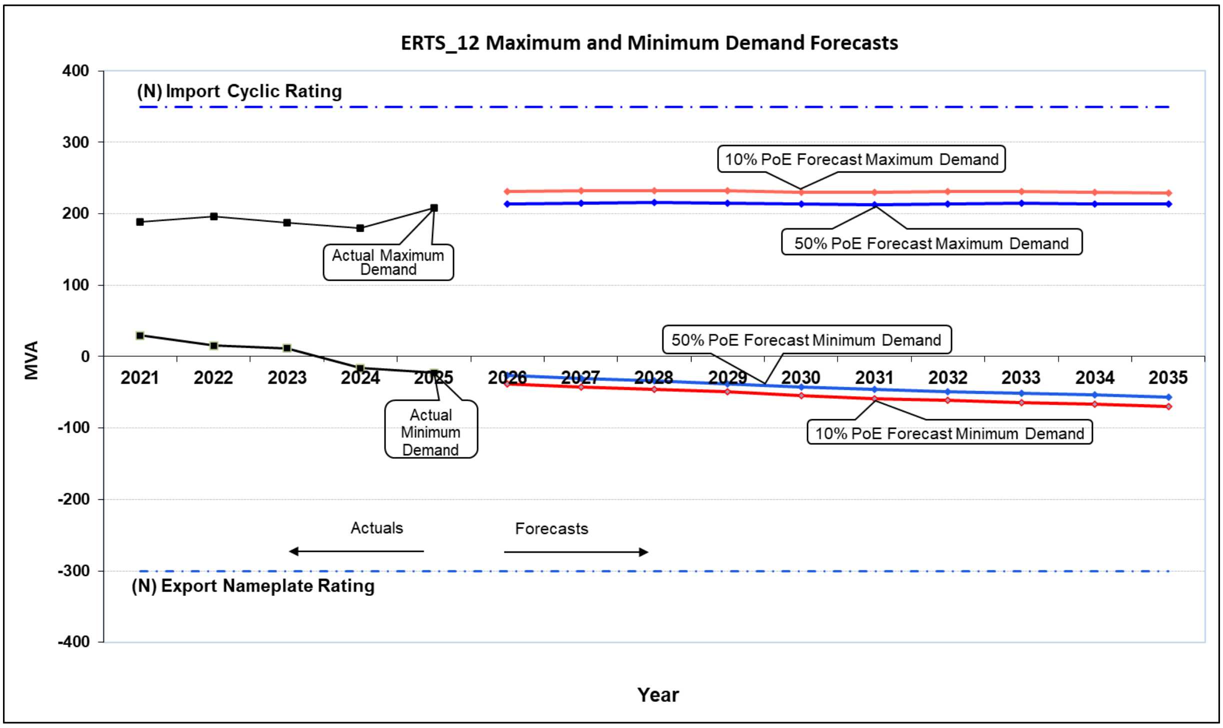
The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

Transformer group ERTS 12: Summer Maximum Demand Forecasts

This bus group supplies United Energy's Mulgrave, and Lyndale zone substations and AusNet's Ferntree Gully, Rowville, and Belgrave zone substations.

The maximum demand in summer 2025 for the ERTS 12 bus group was 206.9 MW (208.6 MVA).

The graph below depicts the historical demand, the ERTS 12 bus group import ratings with both transformers in service (N rating), along with the historical demand and the 10th and 50th percentile maximum demand forecasts.



The graph indicates that both the 10th and 50th percentile forecast maximum demands connected to the bus group ERTS 12 are below its N rating throughout the 10-year forecast period.

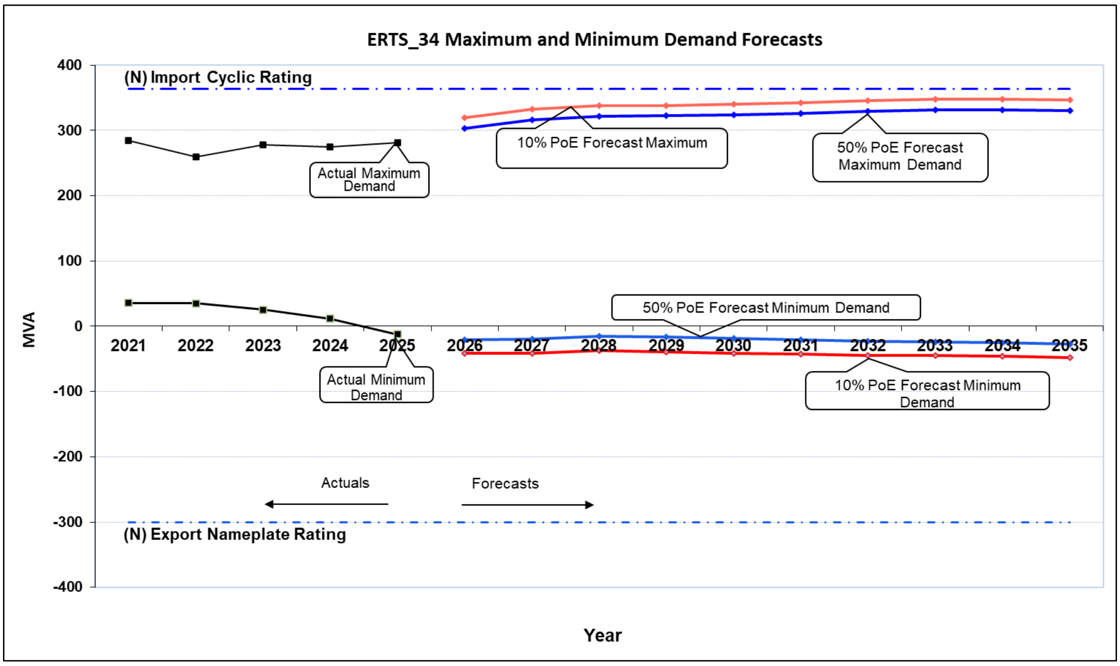
There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

Transformer group ERTS 34: Summer Maximum Demand Forecasts

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

The maximum demand in summer 2025 for the ERTS 34 bus group was 268.1 MW (276.9 MVA).

The graph below depicts the historical demand, the ERTS 34 bus group import ratings with both transformers in service (N rating) along with the historical demand and the 10th and 50th percentile summer maximum demand forecasts.



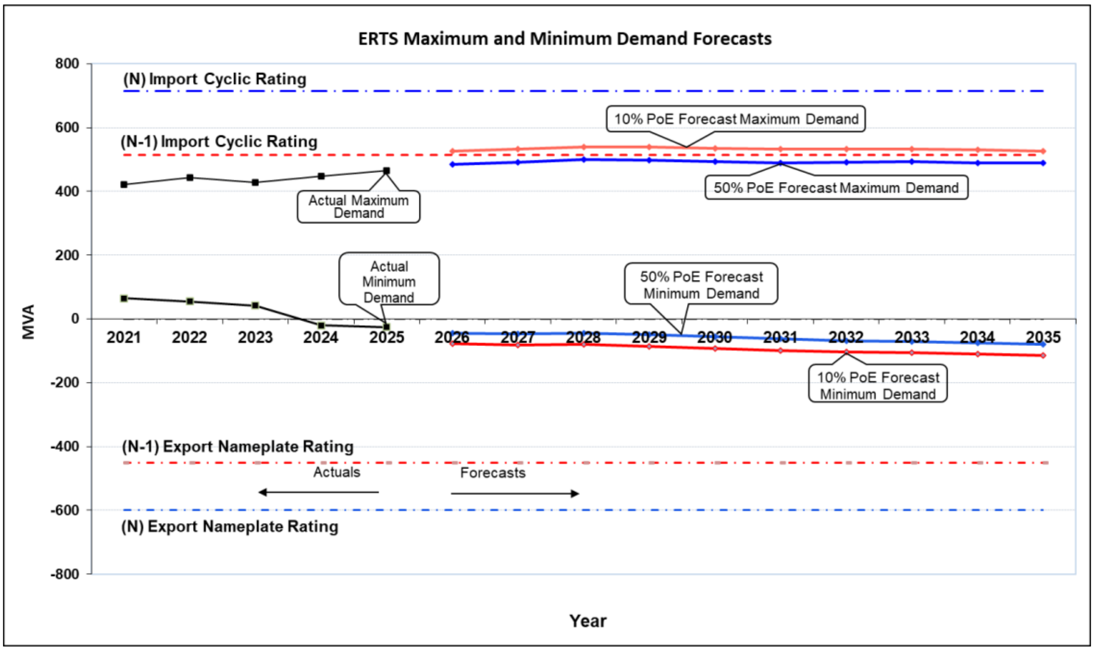
The graph indicates that both the 10th and 50th percentile forecast maximum demands connected to the bus group ERTS 34 are below its N rating throughout the 10-year forecast period.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

ERTS Total Demand Forecasts

ERTS is a summer peaking terminal station. The recorded maximum demand in summer 2025 was 458.1 MW (465.7 MVA).

The graph below shows the historical demand, the 10th and 50th percentile maximum, and minimum demand forecasts together with the station's expected operational N import and export ratings (all transformers in service) and the (N-1) import and export ratings at 40°C ambient temperature.



The above graph indicates that the overall demand at ERTS remains below its N import rating throughout the 10-year forecast period. However, the maximum demand at ERTS exceeds the (N-1) station import rating under 10% PoE in 2026 and stays marginally above the (N-1) rating over the 10-year planning period. The 50% POE forecast is expected to be within the (N-1) rating for the same period.

There is approximately 36 MVA of load transfer available at ERTS via the distribution network for summer 2025/26.

If one of the 220/66 kV transformers at ERTS is taken offline during times of maximum demand and the (N-1) station import rating is exceeded, the OSSCA[73] load shedding scheme, which is operated by AusNet Transmission Group's NOC[74], 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 import capability of the station would be restored at zone substation feeder level in accordance with United Energy's and AusNet Distribution's operational procedures after the operation of the OSSCA scheme.

Given the small amount of load at risk at the 10th percentile temperature over the 10 year planning horizon, augmentation of ERTS to alleviate import constraints is not expected to be economically justified over the next decade.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

It is estimated that:

- For 6 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 1 hour per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.69.

73 Overload Shedding Scheme of Connection Asset.

74 Network Operations Centre.

FISHERMAN'S BEND TERMINAL STATION 66 kV (FBTS 66 kV)

FBTS 66 kV is a terminal station shared by both CitiPower (currently 98.4.%) and Powercor (currently 1.6%). 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 42,734 customers in the areas of Docklands, Southbank, Port Melbourne, Fisherman's Bend, Albert Park, Middle Park, St Kilda West and the southwest corner of the CBD.

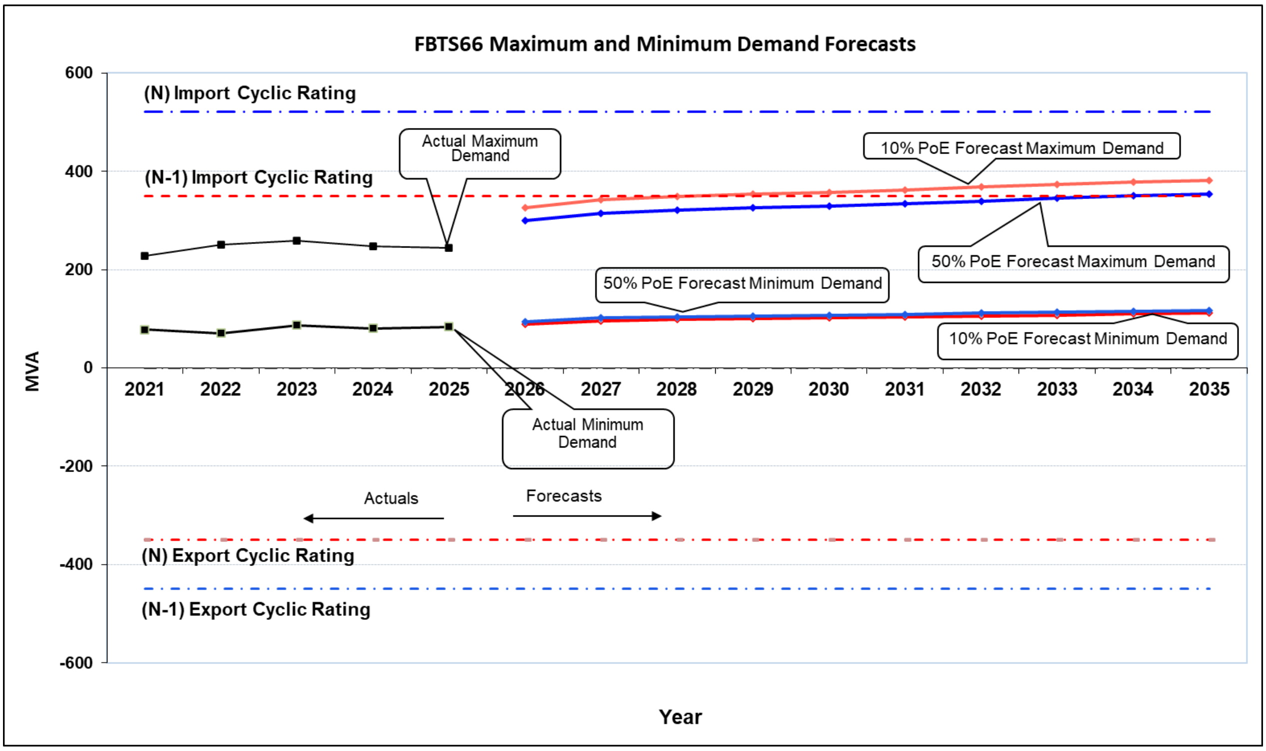
Embedded generation

About 11.7 MW of solar PV is installed on the CitiPower distribution system connected to FBTS. This includes all the residential and small-commercial rooftop solar PV systems (<1 MW).

Magnitude, probability and impact of constraints

The maximum demand on the station reached 235.9 MW (244.4 MVA) in summer 2025.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts during the summer periods over the next ten years, together with the station's operational N and N-1 import and export ratings.



It should be noted that the ratings shown above are thermal ratings only. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown above therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

It is estimated that:

- For 12 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand summer forecast.

- The station load power factor at the time of peak demand is 0.96.

In relation to minimum demand, it is estimated that:

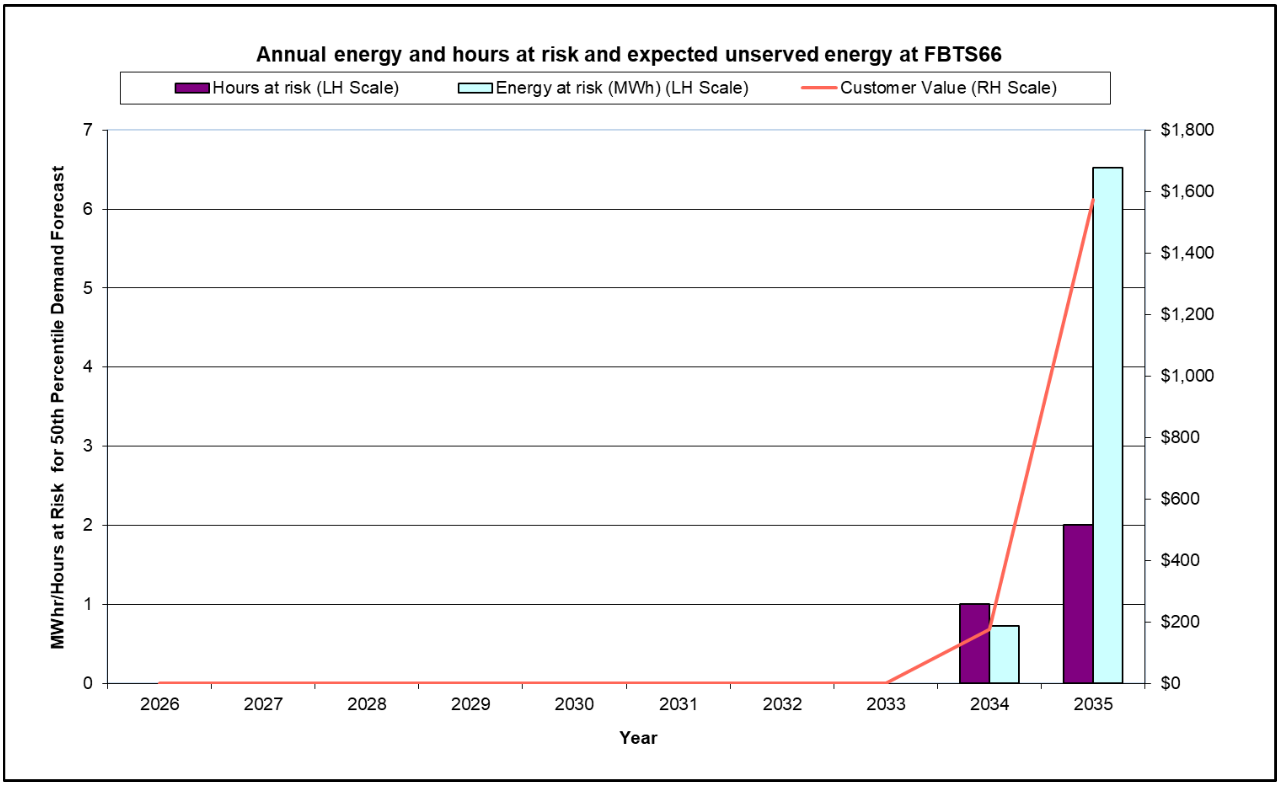
- For 42 hours per year, 95% of the minimum demand is expected to be reached.

- The station load power factor at the time of minimum demand is 0.99.

The (N) import rating on the chart indicates the maximum demand that can be supplied from FBTS with all transformers in service. The “N-1” import rating on the chart is the load that can be supplied from FBTS with one 150 MVA transformer out of service.

The graph above shows from 2027, at the 10th percentile maximum demand, there is a risk of insufficient capacity (N-1 rating) at the station to supply all maximum demand if a forced outage of a transformer occurs. It also shows that from 2032, at the 50th percentile maximum demand, there is a risk of insufficient capacity (N-1 rating) at the station to supply all maximum demand if a forced outage of a transformer occurs.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $36,371 per MWh.



Key statistics relating to energy at risk and expected unserved energy for the year 2035 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	6.5	$0.2 million
Expected unserved energy at 50th percentile maximum demand	0.04	$1,573
Energy at risk, at 10th percentile maximum demand forecast	159.6	$5.8 million
Expected unserved energy at 10th percentile maximum demand	1.06	$38,477
70/30 weighted expected unserved energy value (see below)	**0.3**	**$0.01 million**

Under the probabilistic planning approach[75], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[76]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[77]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $0.01 million.

The table headed "Export" below shows that an that an increase in the volume of output from embedded generators connected downstream of FBTS is forecast over the planning period. It is expected that there will be sufficient export capacity at FBTS to accommodate all embedded generation output over the ten-year planning horizon.

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 network import constraint:

1. Installation of a fourth 220/66 kV transformer (150 MVA) at FBTS at an indicative capital cost of $35 million, which equates to a total annual cost of $2.7 million.

2. Demand reduction: There is an opportunity to develop several 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.

3. Embedded generation: Connection of additional embedded generation will contribute into the 66 kV infrastructure ex-FBTS. This may defer the need for any capacity augmentation at FBTS.

75 See section 3.

76 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

77 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

4. 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 maximum demand at FBTS to alleviate import constraints, it is proposed to install a fourth 220/66 kV transformer (150 MVA) at FBTS at an indicative capital cost of $35 million. This equates to a total annual cost of approximately $2.7 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 within the ten-year forecast period.

CitiPower expects that any load at risk will be managed through load transfers or other cost-effective operational measures.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

Fisherman’s Bend Terminal Station

Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station: CitiPower (98.4%) and Powercor (1.6%)

	MVA	
Normal cyclic rating with all plant in service	521	via 3 transformers (summer)
Summer N-1 Station Import Rating:	349	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	391	
Summer N-1 Station Export Rating:	349	[See Note 7]
Winter N-1 Station Export Rating:	391	[See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	299.2	314.7	320.6	325.3	329.1	333.8	339.7	345.5	350.2	354.3
50th percentile Winter Maximum Demand (MVA)	245.2	255.1	262.7	270.0	276.9	285.5	294.7	303.4	311.0	318.4
10th percentile Summer Maximum Demand (MVA)	326.9	343.1	348.9	353.3	356.9	361.4	368.4	373.2	378.2	382.2
10th percentile Winter Maximum Demand (MVA)	258.7	268.9	276.8	284.6	291.3	300.1	309.2	318.2	326.5	335.2
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	6.5
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	4.8	12.2	24.5	55.7	85.4	122.6	159.6
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	1.5	2.5	3.5	5.5	7.0	8.5	10.5
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.03	0.08	0.16	0.37	0.57	0.81	1.06
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M	$0.02M	$0.03M	$0.04M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M	$0.01M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	88.7	96.0	98.3	100.2	101.9	103.6	105.6	107.7	109.8	111.6
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The summer 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

FRANKSTON TERMINAL STATION (FTS)

FTS is a 66 kV switching station supplied via three 66 kV supply routes from CBTS.

Embedded generation

About 85 MW of rooftop solar PV is installed within the distribution system connected to FTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

There is one embedded generation site (11.76 MVA of biogas and 18.4 MVA of solar PV commissioned in 2023) over 1 MW connected at FTS 66 kV.

Magnitude, probability, and impact of constraints

In 2017, a project was completed to implement dynamic line ratings on the CBTS-FTS 66 kV double circuit tower lines using actual wind velocity, to increase the ratings of the two lines.

Arrangements relating to the ownership of assets supplying FTS, as well as the ratings of those assets are listed in the table below. For this risk assessment, it is assumed that the CBTS-FTS lines are rated as per the higher of the two wind speed ratings shown.

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

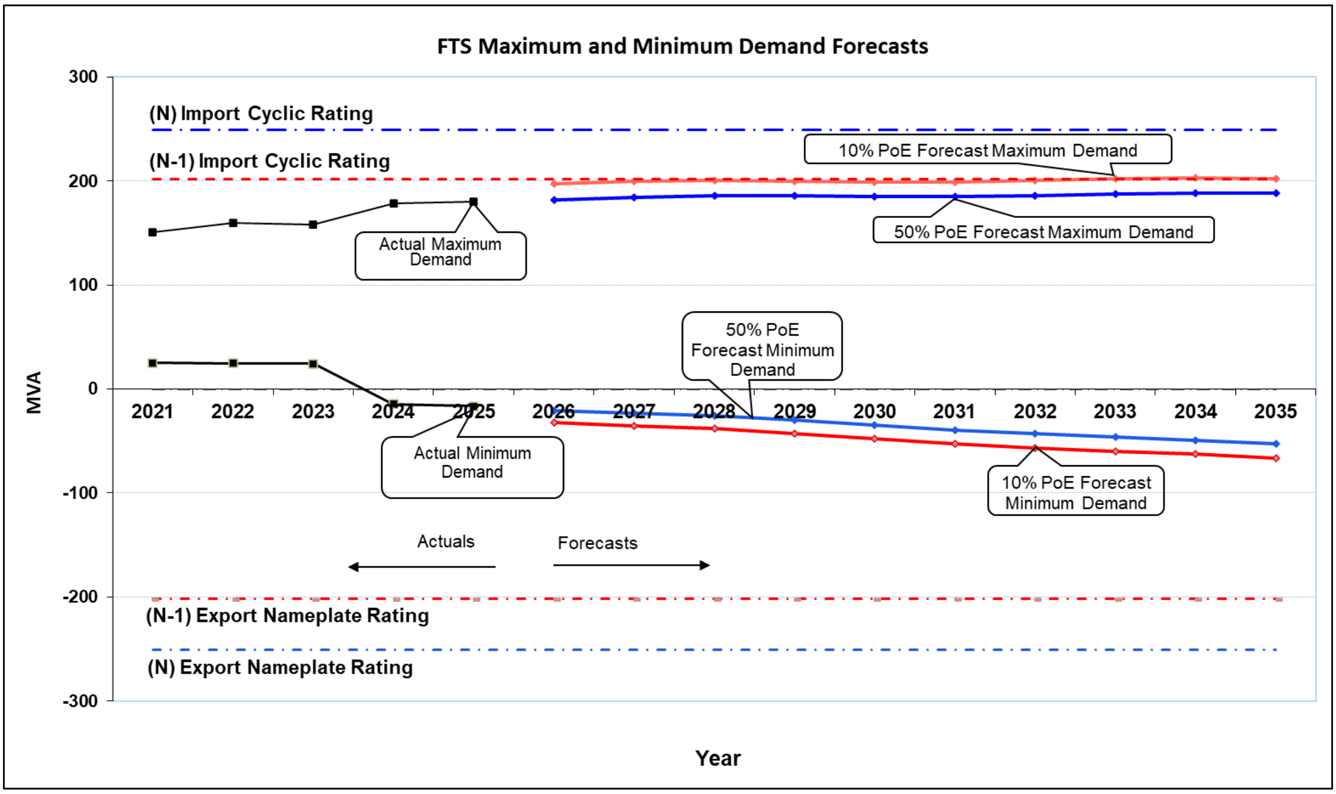
There is approximately 22 MVA of load transfer available at FTS for summer 2025/26.

The various 66 kV supply routes and ownership arrangements mean that the risk assessment for FTS is more complicated than for other terminal stations. Whilst there are more limiting constraints within the sub-transmission loop, as far as transmission connection assets are concerned, load flow studies indicate that the lowest (N-1) import rating of FTS during summer corresponds to the outage of the CBTS-CRM 66 kV line which is limited by the thermal rating of the CBTS-FTS #2 66 kV line.

If the CBTS-FTS 66 kV lines (owned and operated by AusNet Transmission Group) become overloaded, AusNet Transmission Group's centralised System Overload Control Scheme (SOCS) 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 sufficiently reduced demand level to avoid further overloading.

The graph below depicts the historical demand, the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational (N-1) import and exports ratings at 40°C ambient temperature.

The (N-1) import rating on the chart indicates the maximum demand that can be supplied from FTS with the CBTS-CRM 66 kV line out of service.



The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 4 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.93.

The graph above indicates that the maximum demand at FTS reaches the (N-1) station import rating under 10% PoE in 2033. However, the 50% PoE maximum demand forecast remains within the (N-1) import rating over the ten-year forecast period.

Based on the current demand forecasts, the need for augmentation of FTS to alleviate import constraints is not expected to arise over the next decade.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

GEELONG TERMINAL STATION (GTS) 66 kV

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 station has been rearranged 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.

GTS is the main source of supply for over 194,278 customers in Geelong and the surrounding area. The station supply area includes Geelong, Corio, North Shore, Drysdale, Waurn Ponds and the Surf Coast.

Embedded generation

A total of 401.5 MW capacity of embedded generation is installed on the Powercor distribution and sub-transmission system connected to GTS. This includes solar, wind natural gas and bio-mass types of generation. It consists of:

- 164.5 MW of large-scale (>1 MW) embedded generation; and
- 237 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the large-scale embedded generation (>5 MW) that is installed on the Powercor network connected to GTS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Mt Gellibrand Wind Farm	Existing Plant	Wind turbine	132
Deakin University Waurn Ponds Microgrid	Existing Plant	Solar Farm	7.8
Shell Refinery	Existing Plant	Gas	19.2
Geelong Hospital	Existing Plant	Gas	5.5

Magnitude, probability and impact of constraints

Due to the operating arrangement at this station, maximum demand comparisons with the N rating are provided against the separate bus groups below, followed by comments on maximum demand comparisons against the N-1 rating shown in the overall station graph.

The following observations and risk assessment are based on actual readings of power flow at the Terminal Station Connection points. It therefore accounts for the existing load and generation combination.

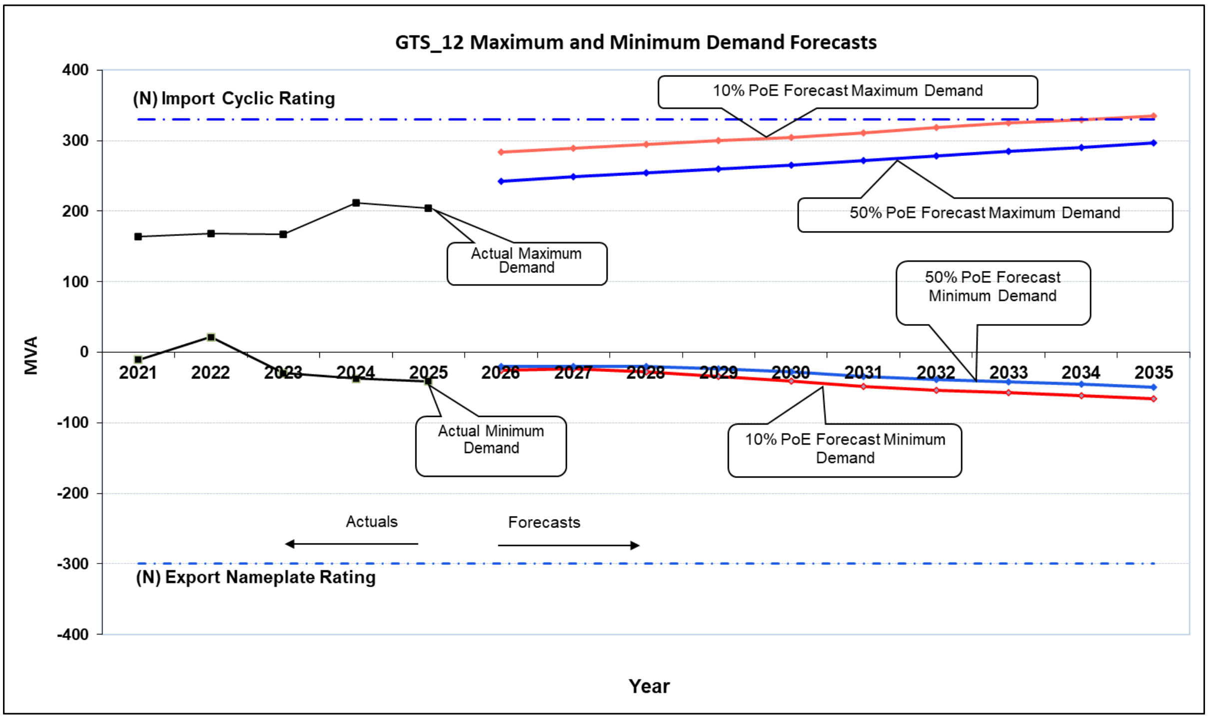
The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figures shown below therefore provide an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

GTS 1 & 2 66kV Bus Group Summer Maximum Demand Forecasts

This bus group supplies Powercor's zone substations at Ford North Shore, Waurn Ponds, Colac, Mt Gellibrand, Gheringhap, Torquay and Winchelsea and 66 kV customer substations Shell Refinery Corio and Blue Circle Cement.

GTS 66 kV buses 1&2 demand is summer peaking. The maximum demand on the GTS 1&2 Bus group reached 201.4 MW (207.4 MVA) in summer 2025. The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service).



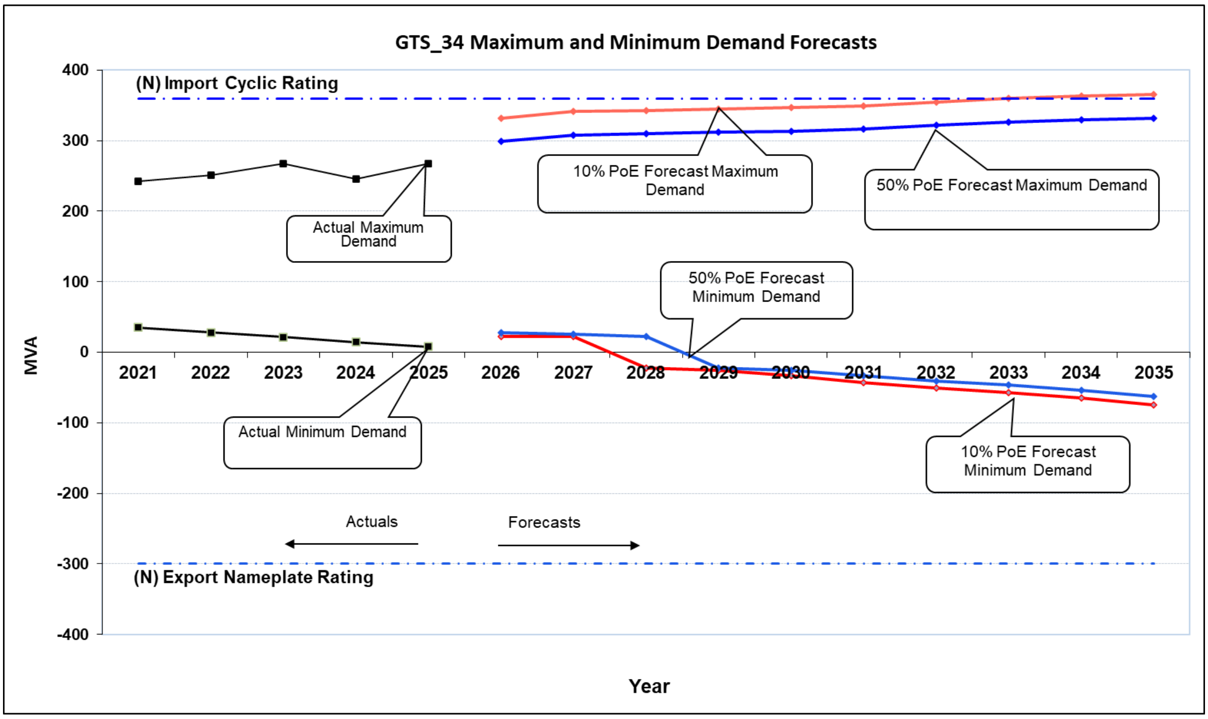
The (N) import rating on the chart indicates the maximum demand that can be supplied from GTS bus 1&2 with two transformers in service. The graph shows that from 2033, at the 10th percentile maximum demand, there is a risk of insufficient capacity (N rating) at the station to supply all maximum demand with all transformers in service.

The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

GTS 3 & 4 66kV Bus Group Summer Maximum Demand 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 256.0 MW (267.2 MVA) in summer 2025.

GTS 66 kV buses 3&4 demand is summer peaking. The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service).



The (N) rating on the chart indicates the maximum demand that can be supplied from GTS bus 3&4 with two transformers in service. The graph shows that from 2032, at the 10th percentile maximum demand, there is a risk of insufficient capacity (N rating) at the station to supply all maximum demand with all transformers in service.

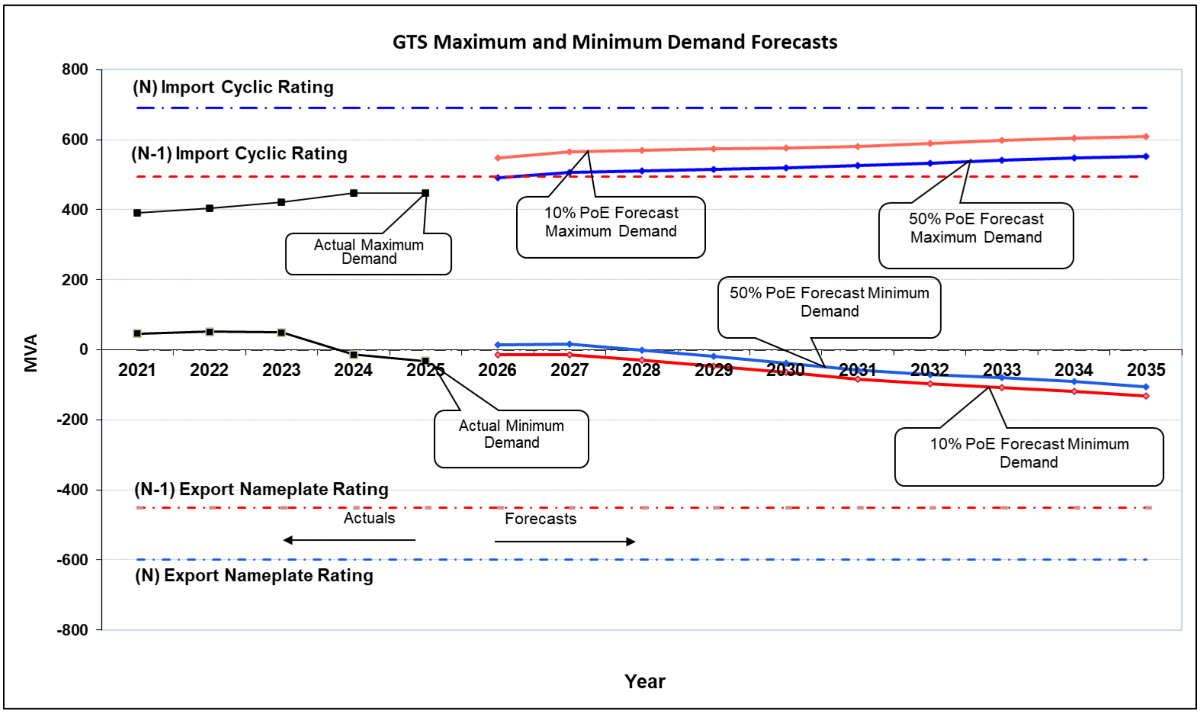
The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

GTS Total Demand Forecasts

GTS is a summer peaking station, and the maximum demand reached 432.8 MW (446.9 MVA) in summer 2025.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import cyclic ratings at 40°C ambient temperature and export nameplate.

The (N) rating on the chart indicates the maximum demand that can be supplied from GTS with all transformers in service.



The above graph indicates that the overall demand at GTS remains below its N import rating within the 10-year forecast period. The graph shows that from 2026, at the 10th and 50th percentile maximum demand, there is a risk of insufficient capacity (N-1 rating) at the station to supply all maximum demand with one transformer out of service.

It is estimated that:

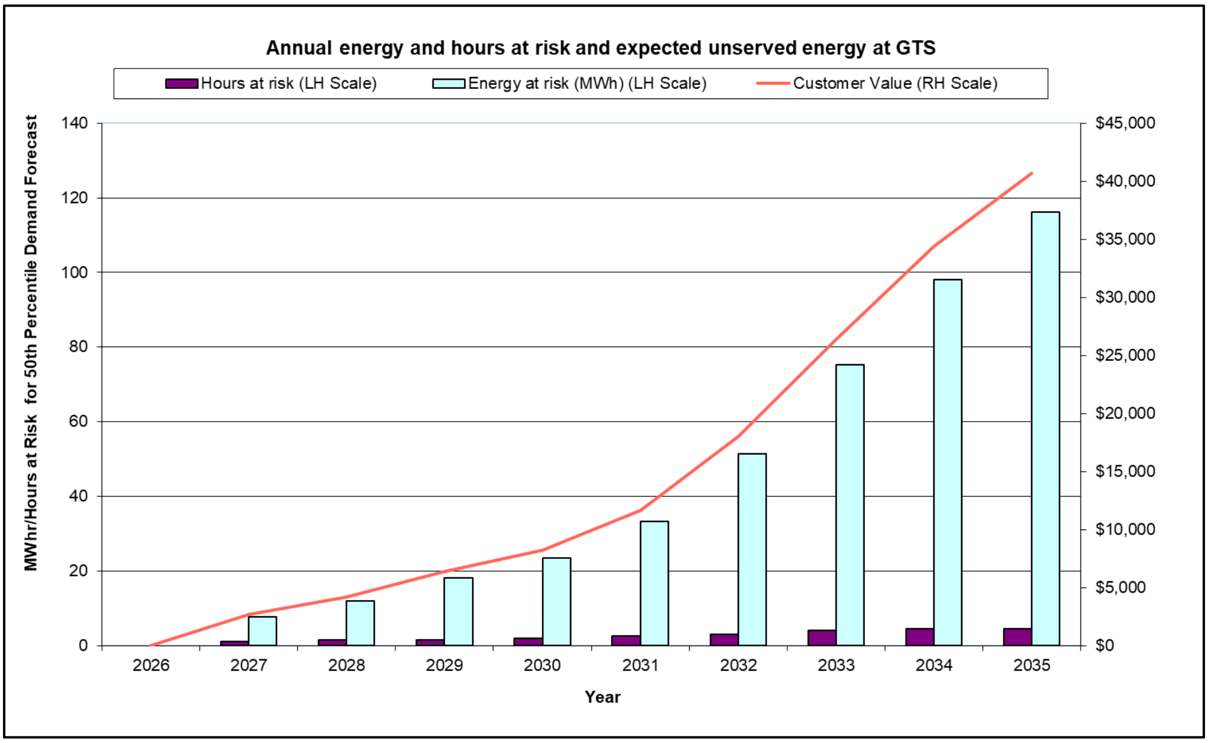
- For 4 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.12.

Load growth at GTS is expected to remain strong due to high population growth and increasing commercial and industrial customer connections.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $39,631 per MWh.



Key statistics relating to energy at risk and expected unserved energy for the year 2035 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	116.3	$4.6 million
Expected unserved energy at 50th percentile maximum demand	1.03	$40,727
Energy at risk, at 10th percentile maximum demand forecast	600.2	$23.8 million
Expected unserved energy at 10th percentile maximum demand	5.31	$210,284
70/30 weighted expected unserved energy value (see below)	**2.31**	**$92,000**

Under the probabilistic planning approach[78], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[79]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[80].

78 See section 3.

79 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

80 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $92,000.

The table headed "Export" below shows that an that an increase in the volume of output from embedded generators connected downstream of GTS is forecast over the planning period. It is expected that there will be sufficient export capacity at GTS to accommodate all embedded generation output over the ten-year planning horizon.

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 network import constraint:

1. Installation of a fifth 220/66 kV transformer (150 MVA) at GTS at an indicative capital cost of $35 million, which equates to a total annual cost of $2.7 million.

2. Demand reduction: There is an opportunity to develop several 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.

3. Embedded generation: Connection of additional embedded generation will contribute into the 66 kV infrastructure ex-GTS. This may defer the need for any capacity augmentation at GTS.

4. 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 maximum demand at GTS to alleviate import constraints, it is proposed to install a fifth 220/66 kV transformer (150 MVA) at GTS at an indicative capital cost of $35 million. This equates to a total annual cost of approximately $2.7 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 within the ten-year forecast period.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

Geelong Terminal Station
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

	MVA	
Normal cyclic rating with all plant in service	690	via 4 transformers (summer)
Summer N-1 Station Import Rating:	494	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	608	
Summer N-1 Station Export Rating:	450	[See Note 7]
Winter N-1 Station Export Rating:	450	[See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	491.7	507.5	511.9	516.4	520.1	525.2	533.1	541.3	547.3	551.7
50th percentile Winter Maximum Demand (MVA)	480.9	494.3	506.9	520.0	532.9	548.7	565.9	581.0	593.6	606.8
10th percentile Summer Maximum Demand (MVA)	548.7	564.9	568.9	573.4	577.1	581.8	589.7	598.7	604.9	609.2
10th percentile Winter Maximum Demand (MVA)	541.3	555.0	567.6	580.7	592.8	609.8	628.3	643.9	656.3	668.9
N-1 energy at risk at 50% percentile demand (MWh)	0.0	7.6	11.9	18.2	23.5	33.3	51.4	75.2	98.1	116.3
N-1 hours at risk at 50th percentile demand (hours)	0.0	1.0	1.5	1.5	2.0	2.5	3.0	4.0	4.5	4.5
N-1 energy at risk at 10% percentile demand (MWh)	103.9	176.5	196.6	220.6	241.4	270.2	335.9	432.4	516.5	600.2
N-1 hours at risk at 10th percentile demand (hours)	4.5	5.5	5.5	5.5	6.5	7.5	9.0	12.0	13.5	16.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.07	0.11	0.16	0.21	0.29	0.45	0.66	0.87	1.03
Expected Unserved Energy at 10th percentile demand (MWh)	0.92	1.56	1.74	1.95	2.13	2.39	2.97	3.82	4.57	5.31
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M	$0.01M	$0.02M	$0.03M	$0.03M	$0.04M
Expected Unserved Energy value at 10th percentile demand	$0.04M	$0.06M	$0.07M	$0.08M	$0.08M	$0.09M	$0.12M	$0.15M	$0.18M	$0.21M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.01M	$0.02M	$0.02M	$0.03M	$0.03M	$0.04M	$0.05M	$0.06M	$0.08M	$0.09M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	14.8	13.0	28.8	46.0	64.3	83.9	97.3	107.2	119.1	131.8
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:
1. “N-1” means cyclic station output capability rating with outage of one transformer. The summer 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

GLENROWAN TERMINAL STATION 66 kV (GNTS 66 kV)

Glenrowan Terminal Station (GNTS) consists of one 125 MVA 220/66kV three phase transformer and one 150 MVA 220/66 kV three phase transformer.

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.

Embedded generation

A total of 337.3 MW of embedded generation capacity is installed on the AusNet sub-transmission and distribution systems connected to GNTS. It consists of:

- 263 MW of large-scale embedded generation, predominately solar farms; and
- 74.3 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the registered embedded generators (>5 MW) that are installed on the AusNet network connected to GNTS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Winton Solar Farm (WISF)	Existing Plant	Solar PV	85
Glenrowan West Solar Farm (GWSF)	Existing Plant	Solar PV	110
Mokoan Solar Farm (MKSF)	New Plant	Solar PV	46
Wangaratta Solar Farm (WNSF)	New Plant	Solar PV	22

Magnitude, probability and impact of constraints

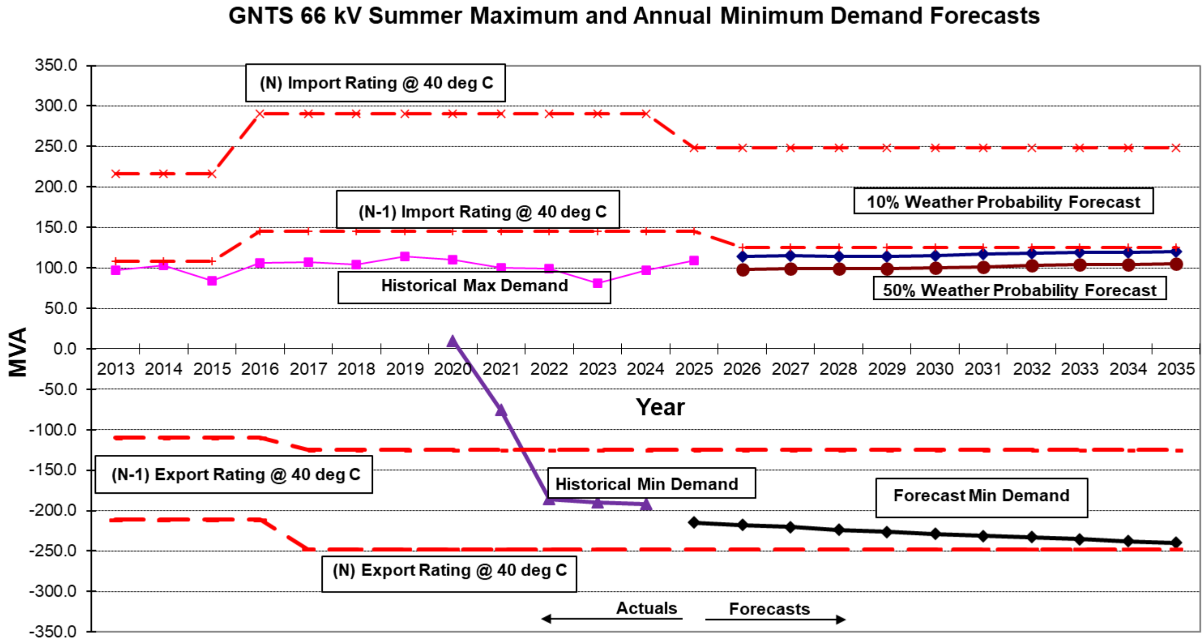
Historically, maximum demand at GNTS has occurred in winter. The rate of growth in summer and winter maximum demand at GNTS 66 kV has been low in recent years, and winter maximum demand is forecast to continue increasing slowly, averaging around 3.2% per annum for the 10-year planning horizon. Summer maximum demand is forecast to continue increasing at around 0.6% per annum for the 10-year planning horizon.

The maximum demand on the station reached 106 MW (109 MVA) in summer 2024/25 and 105.8 MW (110 MVA) in winter 2024.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts, together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at an ambient temperature of 40°C.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



The summer demand at GNTS 66 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 0.98 at summer maximum demand.

The graph shows that there is no energy at risk under 50th percentile or 10th percentile maximum demand forecasts over the next ten years. There is therefore not expected to be any need for augmentation to alleviate import constraints over the ten year planning period.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of 1.0 at the time of minimum demand.

Forecast minimum demand exceeds the N-1 export rating at GNTS. By 2035 there is projected to be a maximum of 115 MVA of embedded generation at risk of being constrained off in the event of a transformer outage. This equates to an expected volume of export energy curtailed of 575 MWh in 2035.

In the event of a transformer outage at GNTS the generators may need to reduce generation to avoid overloading the remaining transformer. AEMO has a constraint equation to manage power flows in accordance with the terminal station transformer export rating. The generators are sent dispatch instructions to reduce generation if the constraint equation binds. Any generation reduction is implemented through AEMO's dispatch process. In addition to this there is a run-back scheme to quickly reduce generation should a contingency event take place at GNTS. This scheme will ensure the remaining transformer is not overloaded following a contingency event.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

GLENROWAN TERMINAL STATION 66kV Loading (GNTS)
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

Normal import cyclic rating with all plant in service	248	MVA via 2 transformers (Summer peaking)
Summer import N-1 Station Rating	125	MVA [See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating	125	MVA
Normal export rating with all plant in service	248	MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	125	MVA [See Note 7 below for interpretation of Export rating]

Import	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
50th percentile Summer Maximum Demand (MVA)	98.7	99.5	99.0	99.1	99.7	101.0	102.7	103.8	104.4	105.3
50th percentile Winter Maximum Demand (MVA)	113.9	117.2	121.3	126.1	136.2	143.6	147.2	149.1	150.9	151.5
10th percentile Summer Maximum Demand (MVA)	114.1	115.0	114.4	114.2	114.9	116.7	118.1	119.1	119.2	120.1
10th percentile Winter Maximum Demand (MVA)	123.4	126.9	131.3	136.2	146.8	154.6	159.1	160.8	162.7	162.6
N - 1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	35	129	216	277	352
N - 1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	8	23	32	42	52
N - 1 energy at risk at 10th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N - 1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.0	1.2	1.6
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.02M	$0.04M	$0.05M	$0.06M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.02M	$0.03M	$0.03M	$0.04M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	-214.6	-220.2	-223.6	-226.6	-228.9	-231.2	-233.0	-235.1	-237.6	-239.6
Maximum generation at risk under N-1 (MVA)	89.6	95.2	98.6	101.6	103.9	106.2	108.0	110.1	112.6	114.6
N-1 energy curtailment (MWh)	92107	100801	106229	111244	115493	119340	121942	124921	129073	132575
Expected volume of export energy curtailed for N-1 (MWh)	399.1	436.8	460.3	482.1	500.5	517.1	528.4	541.3	559.3	574.5

Note: Station ratings are higher than the P10/P50 forecasts for both winer and summer for the plannining horizon. As no EUE risks for N situations in both summer and winter details for N risks are not included in the above 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the sector values given in Section 3.2, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.
8. WNSF generation was not accounted in the risk calculations as it was commissioned outside of the assessment 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.

Embedded generation

About 154.8 MW of rooftop solar PV is installed within the distribution system connected to HTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

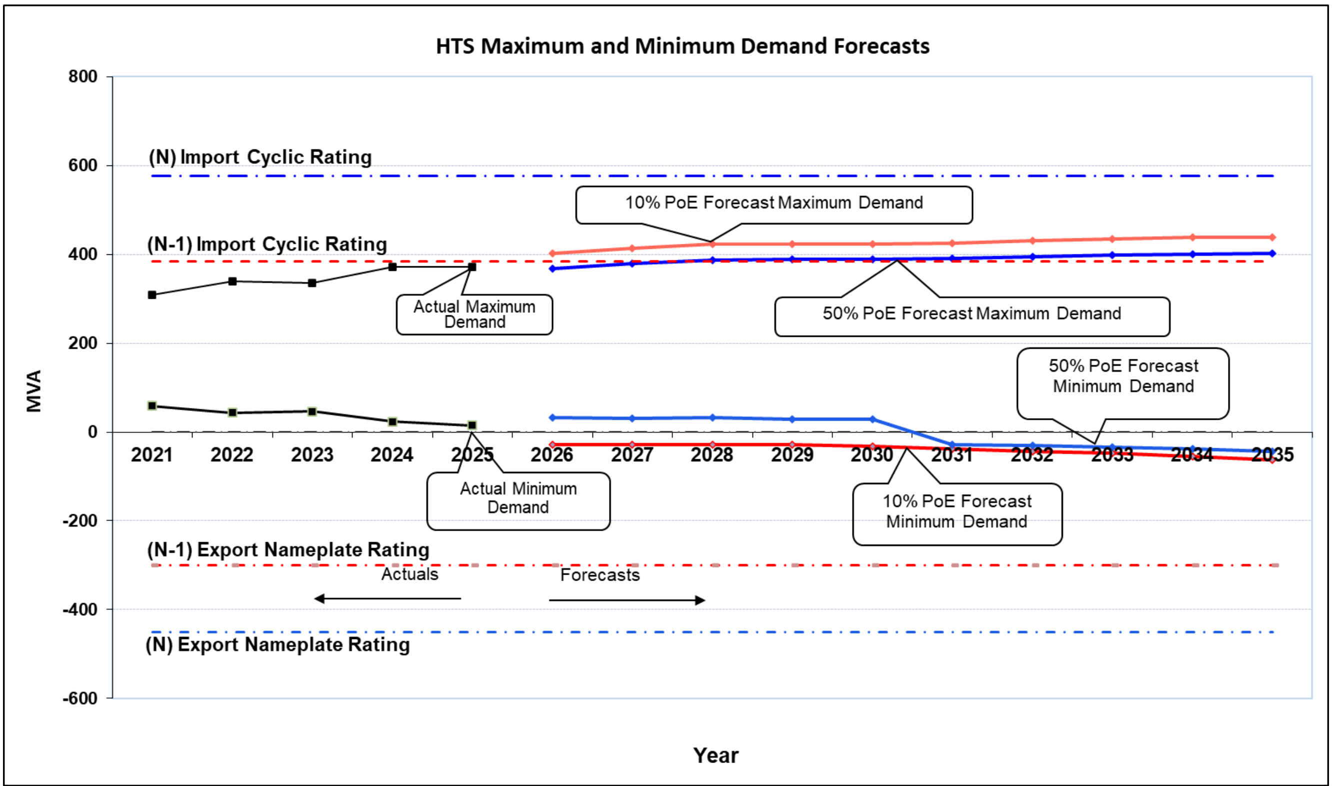
There are no embedded generation units over 1 MW connected at HTS.

Magnitude, probability, and impact of constraints

HTS is a summer critical terminal station. The station reached a maximum demand of 361.8 MW (371.5 MVA) in summer 2025.

The graph below shows the historical demand, the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational N import and export ratings (all transformers in service) and the (N-1) import and export ratings at 40°C ambient temperature.

The export ratings on the chart reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.77.

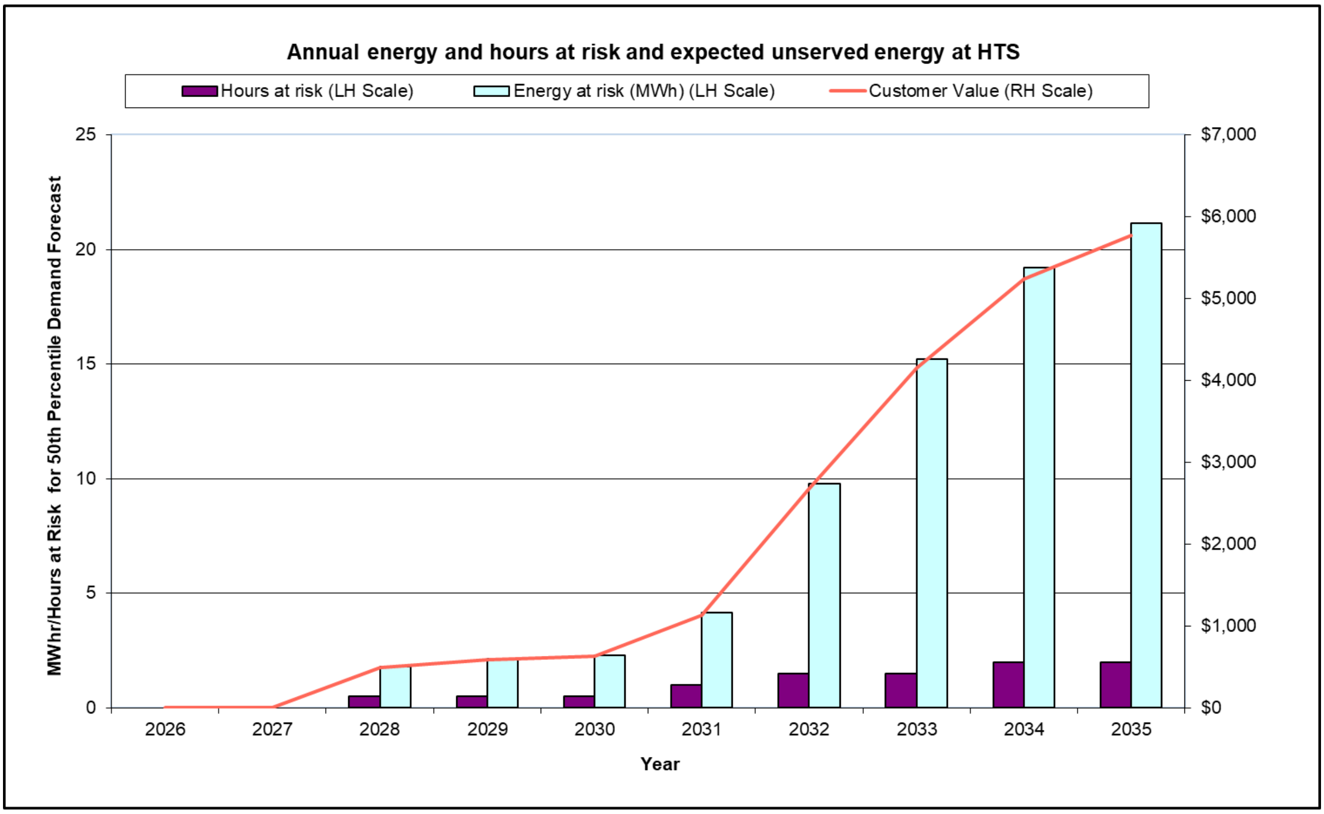
The N import rating on the graph indicates the maximum demand that can be supplied from HTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that with one transformer out of service, the maximum demand at HTS exceeds the (N-1) station import rating under 50% PoE and 10% PoE in 2028 and 2026 respectively.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

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, valued at the VCR for this terminal station, which is $41,171 per MWh.

The Suburban Rail Loop project is expected to further increase demand at HTS. The impact of such projects is excluded from this year's forecast until more details are confirmed.



Key statistics relating to energy at risk and expected unserved energy for 2035 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR ($million)
Energy at risk, at 50th percentile demand forecast	21	$0.87
Expected unserved energy at 50th percentile demand	0.14	$0.0
Energy at risk, at 10th percentile demand forecast	110	$4.6
Expected unserved energy at 10th percentile demand	1.27	$0.05
70/30 weighted expected unserved energy value (see below)	**0.48**	**$0.02**

Under the probabilistic planning approach[81], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[82]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under the probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[83]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $0.02 million. On the basis of the current forecasts, the need for augmentation of HTS to alleviate import constraints is not expected to arise over the next decade.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

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[84] load shedding scheme which is operated by AusNet Transmission Group's TOC[85] 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.

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 has established and implemented the necessary plans that enable load transfers under contingency

81 See section 3.1.

82 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

83 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

84 Overload Shedding Scheme of Connection Asset.

85 Transmission Operations Centre

conditions, via both 66 kV sub-transmission 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 89 MVA for summer 2025/26.

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.

Joint planning studies previously conducted with AEMO identified that establishment of a new terminal station connection point in the Dandenong area would be the preferred solution to address constraints in the area. This was predominantly driven by the load at risk associated with the 220 kV line constraints in the area as well as several 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.

The capital cost of installing a new 220/66 kV terminal station in Dandenong and related sub-transmission works is estimated to be more than $100 million with an estimated total annual cost of approximately $7.8 million.

The need for a new terminal station is unlikely to be economically justified within the ten-year planning horizon. United Energy will continue to work with AEMO on this joint planning exercise to assess the need for and timing of any new terminal station development in the Dandenong area.

Preferred network option(s) for alleviation of constraints

Based on the current forecasts and the load-transfers available, the need for augmentation of HTS to alleviate import constraints is not expected to arise over the next decade.

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 operational 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 availability, an AusNet Transmission Group spare 220/66 kV transformer for metropolitan areas can be used to temporarily replace a failed transformer.
2. Establish a new 220/66 kV terminal station in the Dandenong area to off-load HTS and the surrounding terminal stations and transmission lines. Based on the current 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 pages provide more detailed data on the station rating, demand forecasts, import and export constraints.

HEATHERTON TERMINAL STATION 66kV

Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station:	United Energy (100%)
Station operational rating (N elements in service):	577 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Import Rating:	384 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	421 MVA
Summer N-1 Station Export Rating:	300 MVA [See Note 7]
Winter N-1 Station Export Rating:	300 MVA [See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	368.8	378.5	387.7	388.4	388.7	390.7	394.8	398.6	401.0	402.0
50th percentile Winter Maximum Demand (MVA)	312.2	330.1	341.7	349.6	357.7	368.6	381.0	391.9	400.2	408.0
10th percentile Summer Maximum Demand (MVA)	402.3	412.8	422.3	423.9	424.1	425.8	430.3	434.2	437.7	439.2
10th percentile Winter Maximum Demand (MVA)	329.9	347.9	360.1	368.6	377.2	389.2	402.3	413.8	422.2	430.7
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	1.8	2.1	2.3	4.1	9.8	15.2	19.2	21.1
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.5	0.5	0.5	1.0	1.5	1.5	2.0	2.0
N-1 energy at risk at 10% percentile demand (MWh)	21.6	44.1	77.4	84.3	85.1	93.4	119.7	146.2	172.6	191.4
N-1 hours at risk at 10th percentile demand (hours)	2.0	2.5	4.0	4.5	4.5	5.0	6.0	8.0	8.5	10.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.01	0.01	0.02	0.03	0.06	0.10	0.13	0.14
Expected Unserved Energy at 10th percentile demand (MWh)	0.14	0.29	0.51	0.56	0.56	0.62	0.79	0.97	1.14	1.27
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.01M	$0.02M	$0.02M	$0.02M	$0.03M	$0.03M	$0.04M	$0.05M	$0.05M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.02M	$0.02M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	29.1	28.9	29.1	29.0	32.2	38.6	44.2	48.2	54.9	62.3
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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^{th} and 10^{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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.
8. Negative MVA indicates exporting active power, irrespective of the direction of the reactive power flow.
9. Negative power factor indicates exporting reactive power (capacitive), irrespective of the direction of the active power flow.

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. In addition, 168 small domestic and farming customers along the line route are also supplied from this supply point.

Embedded generation

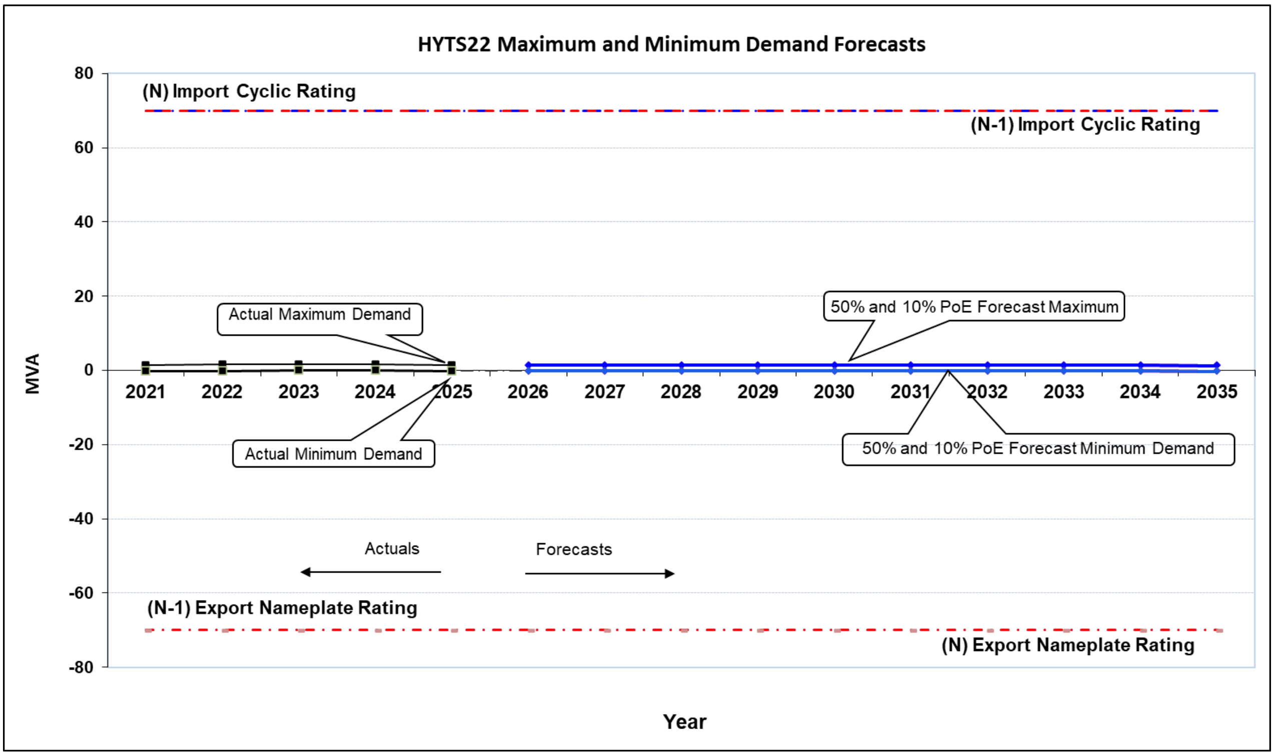
About 128 kW of rooftop solar PV is installed on the Powercor distribution system connected to HYTS 22 kV. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

Magnitude, probability and impact of constraints

The maximum demand on the station reached 1.36 MW (1.41 MVA) in winter 2025.

The 22 kV point of supply was established in late 2009, by utilising the tertiary 22 kV on 2 of the existing 3 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.

The graph depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N-1" import cyclic ratings at 40°C ambient temperature and export nameplate ratings.



The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown above therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

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 power factor at time of peak demand is 0.96.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station power factor at the time of minimum demand is 0.97.

The graph shows that there is sufficient capacity at the station to supply the maximum demand over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action to alleviate import constraints is not expected to arise over the next ten years.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

HORSHAM TERMINAL STATION (HOTS) 66 kV

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 30,623 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).

Embedded generation

A total of 89 MW capacity of embedded generation is installed or proposed to be installed on the Powercor sub-transmission and distribution systems connected to HOTS. It consists of:

- Approximately 53 MW of large-scale embedded generation installed or proposed to be installed; and
- Around 36 MW of rooftop solar PV, which includes all the small-commercial and residential rooftop PV systems that are smaller than 1 MW.

The following table lists the registered embedded generators that are installed or proposed to be installed on the Powercor network connected to HOTS.

Site name	Status	Technology Type	Nameplate capacity (MW)
Kiata Wind Farm	Existing Plant	Wind Turbine	31.05
Diapur (DPWF)	Existing Plant	Wind Turbine	7.4
Ledcourt Solar Farm (LDSF)	Existing Plant	Solar	4.76
Ervins Road Nhill (NREF)	Proposed	Solar	4.9
Stawell Solar Farm (SWSF)	Proposed	Solar	4.76

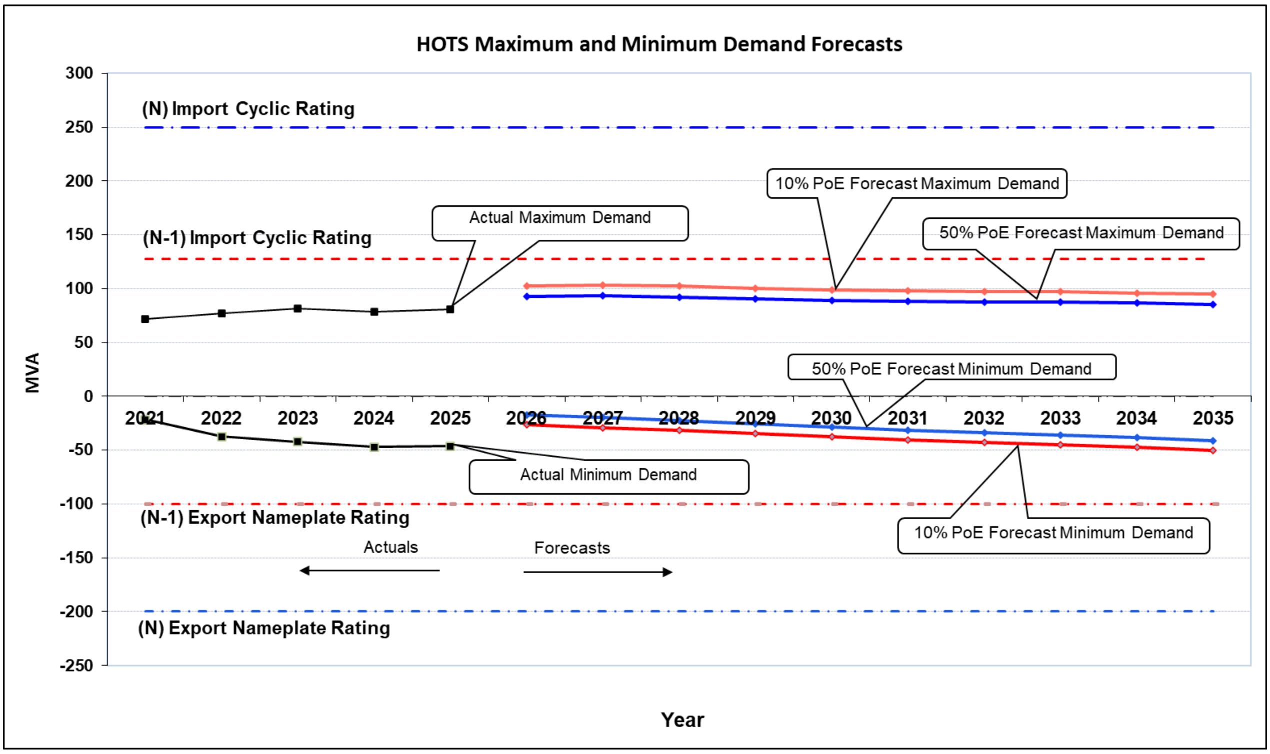
Magnitude, probability and impact of constraints

The maximum demand on the station reached 80.5 MW (80.7 MVA) in summer 2025.

The graph 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 40°C ambient temperature.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



It is estimated that:

- For 2 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of maximum demand is 0.99.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.54.

The graph shows there is sufficient capacity at the station to meet maximum demand 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 to alleviate import constraints is not expected to arise over the next ten years.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

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 currently supplies a total of approximately 205,565 customers in Jemena Electricity Networks and Powercor, in the areas of Sunbury, Sydenham, Tullamarine, Airport West, St. Albans, Woodend, Gisborne, Pascoe Vale, Essendon and Braybrook.

Background

KTS has five 150 MVA transformers and is a summer critical station. Under system normal conditions, the No.1, No.2 & No.5 transformers are operated in parallel as 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.

The following sections examine the two transformer groups separately.

The forecasts for each DB supplied from this station have been prepared using different approaches. The Jemena forecasts have applied a methodology to include diversified non-committed block loads. The forecasts prepared by Powercor have included only committed block loads, noting that there are significant block loads progressing through application processes. Non-network proponents should note that the use of non-committed block loads increases the uncertainty of the nature and timing of the augmentations.

Embedded Generation

A total of 270.3 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to KTS 66 kV. It consists of:

- 234.3 MW of solar PV systems that are smaller than 1 MW, which includes 126.6 MW in the Powercor distribution system and 107.7 MW in the Jemena distribution system; and
- 36 MW capacity of embedded generators greater than 1 MW, which includes 5 MW in the Powercor distribution system and 31 MW in the Jemena distribution system.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figures shown below therefore provide an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

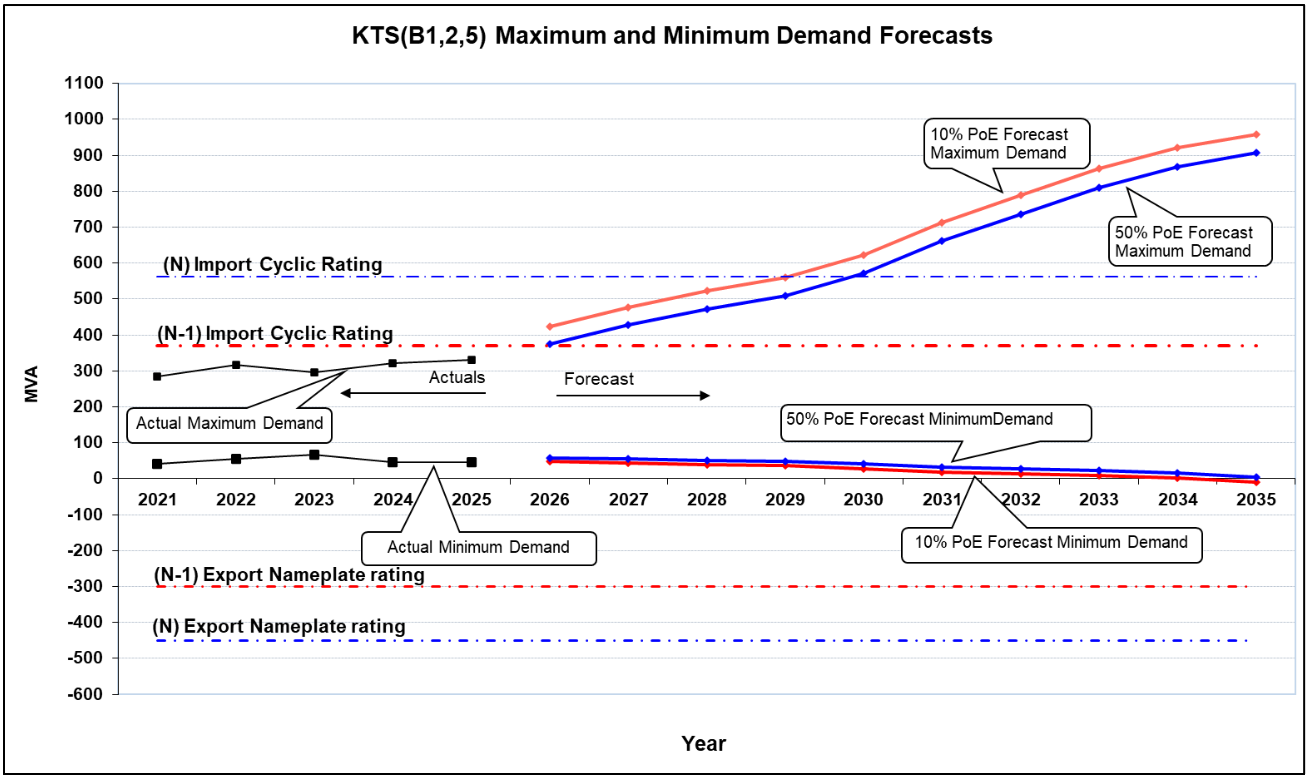
For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

Transformer group KTS (B1,2,5) Summer Maximum Demand Forecasts

Both maximum demand and minimum demand at KTS (B1,2,5) occur in summer.

The graph below shows:

- the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings, with import ratings determined at 40°C ambient temperature;
- actual station maximum demand reached 321.7 MW (331.2 MVA) in December 2024; and
- actual minimum demand reached 46.7 MW (46.7 MVA) in January 2025.



It is estimated that:

- For 16 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 7 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

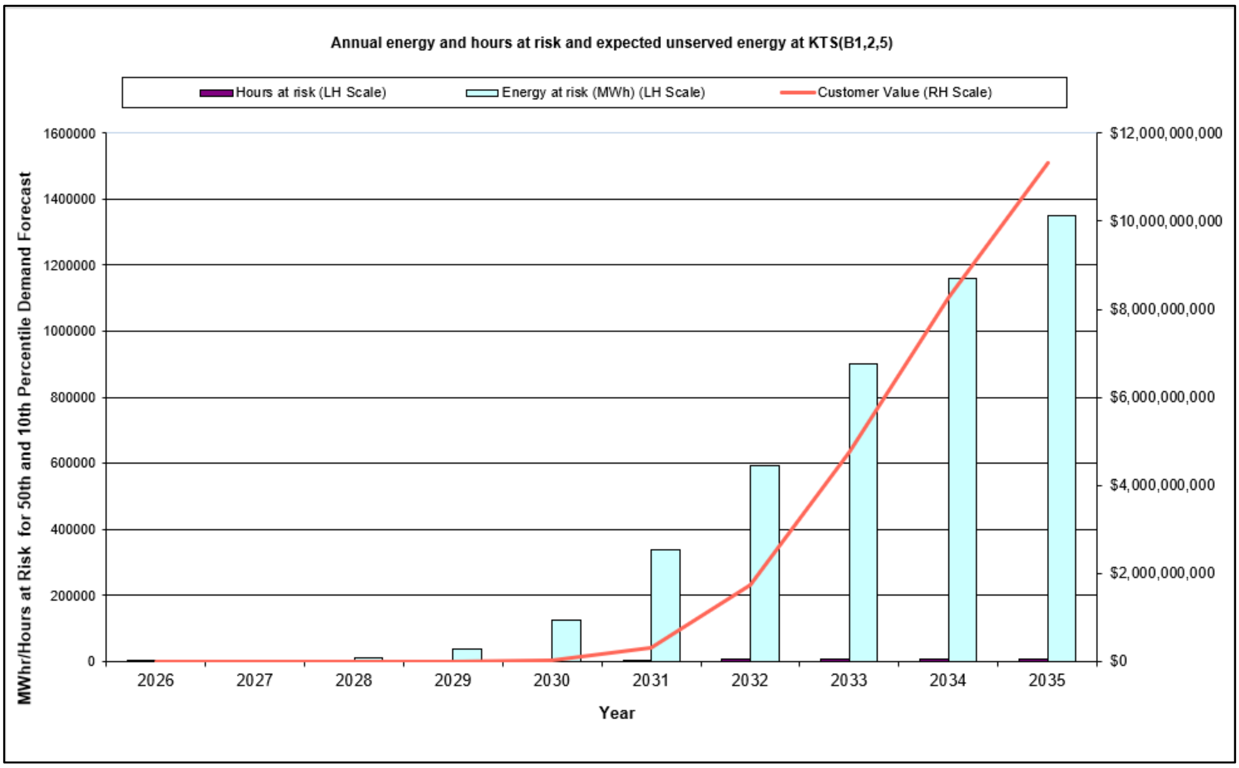
KTS(B1,2,5) is forecast to exhibit strong load growth over the next ten-years, however there is some uncertainty regarding the load realisation of the forecast new block loads.

The above graph shows from 2026, there is insufficient capacity to supply the forecast maximum demand at 50th and 10th percentile temperate at KTS(B1,2,5) if a forced outage of a transformer occurs, and from 2030 the forecast maximum demand at 50th and 10th percentile temperatures is forecast to exceed the station N import rating.

The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the forecast period.

Magnitude, probability and impact of energy risk at KTS(B1,2,5)

The bar chart below depicts the weighted average[86] energy at risk for the 50th and 10th percentile maximum demand forecast, and the hours per year that the weighted average of the 50th and 10th percentile maximum demand forecast is expected to exceed the N-1 and N import capability rating. The line graph shows the value to consumers of the weighted average expected unserved energy in each year. The VCR at KTS is $39,071 per MWh.



86 Weights of 0.7 and 0.3 are applied to the 50th and 10th percentile values, 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 Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

Key statistics relating to energy at risk and expected unserved energy for 2030 under N and N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	105,924	$4,139 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	688.5	$26.90 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	167,526	$6,545 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	1,088.9	$42.54 million
Expected unserved energy at 50th percentile maximum demand under N condition	6.2	$0.24 million
Expected unserved energy at 10th percentile maximum demand under N condition	145.5	$5.68 million
70/30 weighted expected unserved energy value (see below)	856.6	$33.47 million

Under the probabilistic planning approach[87], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 5.4) to determine the expected unserved energy cost in a year due to a major transformer outage[88].

The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[89]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2030 is $33.47 million.

Possible Impact on Customers at KTS(B1,2,5)

System Normal Condition (Both transformers in service)

Applying the 10th percentile maximum demand forecast, there will be insufficient import capacity at KTS B(1,2,5) to meet maximum demand from year 2030 under system normal condition.

87 See section 3.

88 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

89 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

N-1 System Condition

If one of the KTS 220/66 kV transformers is taken offline during peak loading times, causing the KTS (B1,2,5) import rating to be exceeded, the OSSCA[90] load shedding scheme which is operated by AusNet Transmission Group's TOC[91] will act swiftly to reduce the loads in blocks to within transformer import capabilities. Any load reductions that are in excess of the minimum amount required to limit load to the rated import 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.

Possible load transfers away to nearby terminal stations via the HV feeder distribution network would be needed in the event of a transformer failure at KTS (B1,2,5 or B3,4), with total available transfer capability of 15.2 MVA in summer 2025.

Feasible options for alleviation of constraints at KTS(B1,2,5)

The options described below are also applicable to the alleviation of constraints at KTS(B3,4). For completeness, they are set out here.

One or combinations of the following options have been identified to mitigate the risk of supply interruption and/or to alleviate the emerging network import constraint at KTS(B1,2,5) and KTS(B3,4):

1. Upgrade all three transformers at KTS(B1,2,5) and install additional transformation capacity at KTS B(3,4) group and transfer 66 kV exits from KTS B(1,2,5) to KTS B(3,4) group, at an estimated indicative capital cost of $91 million (equating to a total annual cost of approximately $7.1 million).

2. Install a new KTS B(7,8,9) bus group with 3 x 225 MVA 220/66 kV transformers or 2 x 500 MVA 500/132 kV transformers and transfer 66 kV exits between KTS B(1,2,5), KTS B(3,4) and KTS B(7,8,9) groups.

3. Install new 500/132 kV or 500/220 kV and 220/66 kV transformers at Sydenham Terminal Station (SYTS) and transfer load from KTS to SYTS.

4. 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.

5. Embedded generation, connected to the KTS B(1,2,5), may substitute capacity augmentations.

90 Overload Shedding Scheme of Connection Asset.

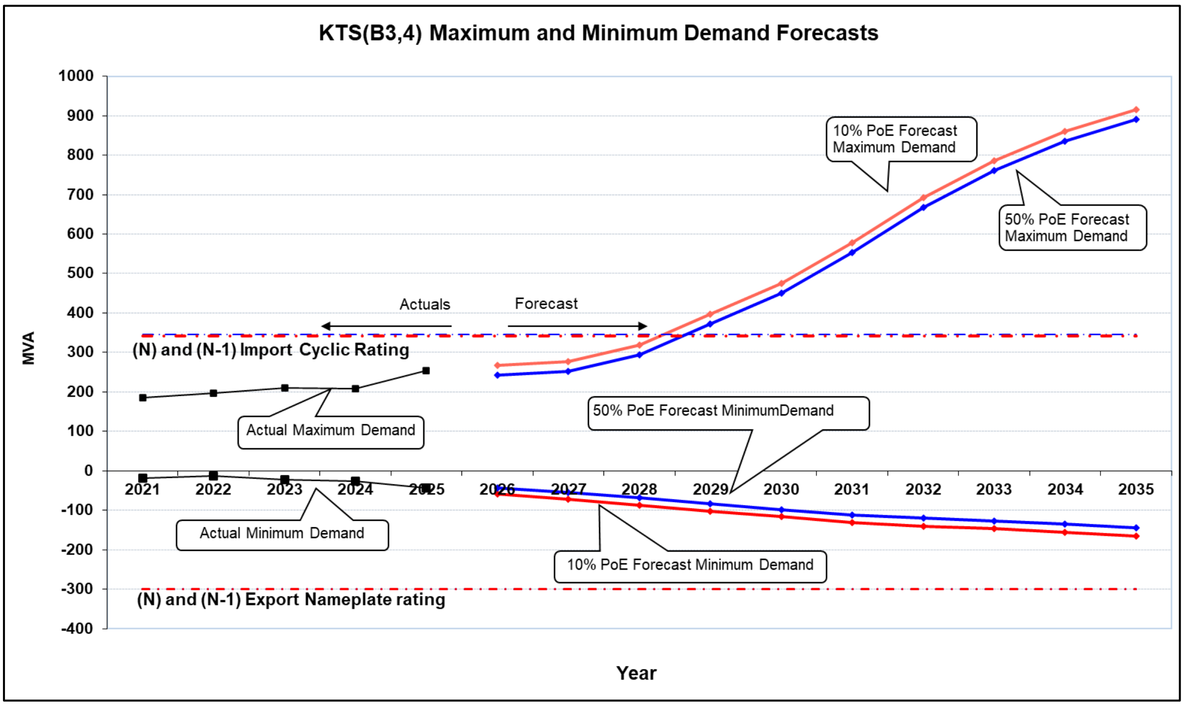
91 Transmission Operations Centre.

Transformer group KTS (B3,4) Summer Maximum Demand Forecasts

Maximum demand and minimum demand on KTS (B3,4) occurs in summer.

The graph below shows:

- the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings, with import ratings determined at 40°C ambient temperature;
- actual station maximum demand reached 246.5 MW (253.2 MVA) in February 2025; and
- actual minimum demand reached -41.5 MW (-43.4 MVA) in January 2025.



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.

It is estimated that:

- For 11 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

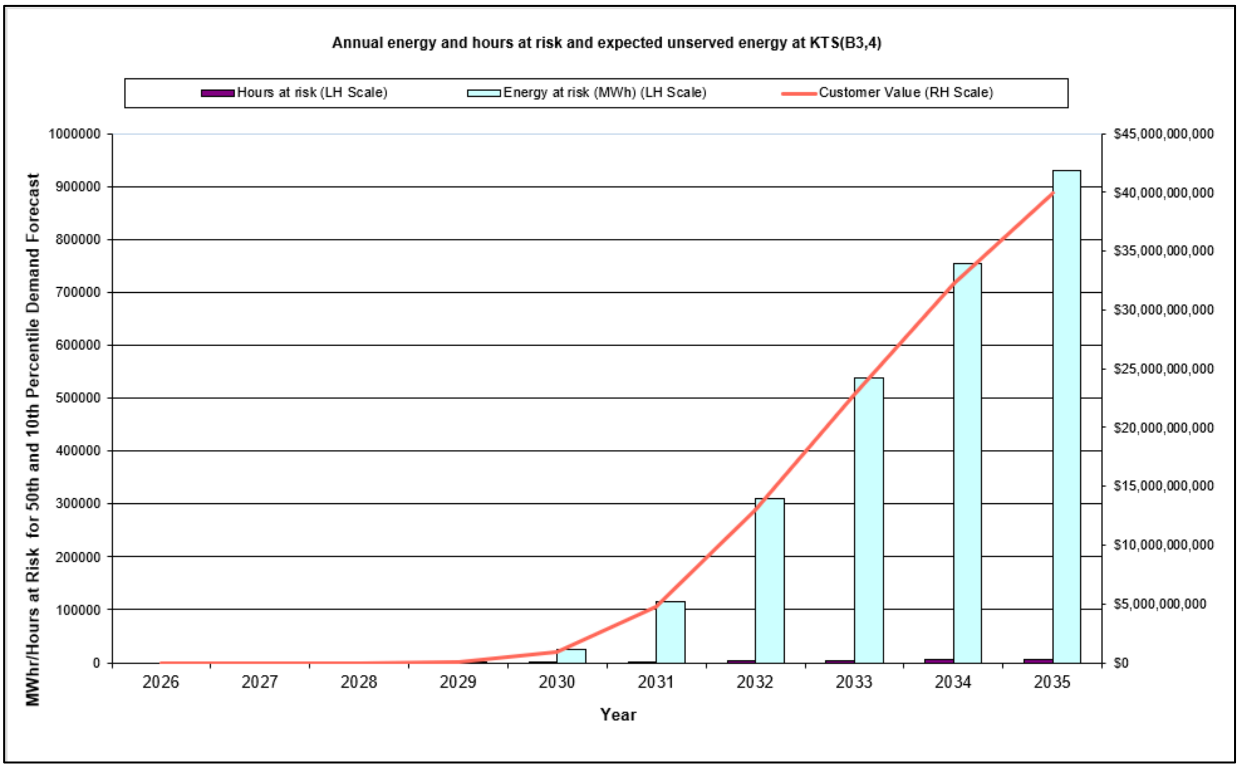
- For 1 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.96.

The above graph shows from 2029, there is insufficient capacity to supply the forecast maximum demand at 50th and 10th percentile temperatures at KTS(B3,4) if a forced outage of a transformer occurs, and from 2029 the forecast maximum demand at 50th and 10th percentile temperatures is forecasted to exceed the station N import rating.

The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the forecast period.

Magnitude, probability and impact of energy risk at KTS(B3,4)

The bar chart below depicts the weighted average[92] energy at risk for the 50th and 10th percentile maximum demand forecast, and the hours per year that the weighted average of the 50th and 10th percentile maximum demand forecast is expected to exceed the N-1 and N import capability rating. The line graph shows the value to consumers of the weighted average expected unserved energy in each year. The VCR at KTS is $44,243 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2029 under N and N-1 outage conditions are summarised in the table below.

92 Weights of 0.7 and 0.3 are applied to the 50th and 10th percentile values, 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 Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	324.9	$14.37 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	1.4	$0.06 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	336.8	$14.90 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	1.5	$0.06 million
Expected unserved energy at 50th percentile maximum demand under N condition	543.6	$24.05 million
Expected unserved energy at 10th percentile maximum demand under N condition	650.5	$28.78 million
70/30 weighted expected unserved energy value (see below)	577	$25.53 million

Feasible options for alleviation of constraints at KTS(B3,4)

The options described below are also applicable to the alleviation of constraints at KTS(B1,2,5). For completeness, they are set out here.

One or combinations of the following options have been identified to mitigate the risk of supply interruption and/or to alleviate the emerging network import constraint at KTS(B3,4) and KTS(B1,2,5):

1. Upgrade all three transformers at KTS(B1,2,5) and install additional transformation capacity at KTS B(3,4) group and transfer 66 kV exits from KTS B(1,2,5) to KTS B(3,4) group, at an estimated indicative capital cost of $91 million (equating to a total annual cost of approximately $7.1 million).

2. Install a new KTS B(7,8,9) bus group with 3 x 225 MVA 220/66 kV transformers or 2 x 500 MVA 500/132 kV transformers and transfer 66 kV exits between KTS B(1,2,5), KTS B(3,4) and KTS B(7,8,9) groups.

3. Install new 500/132 kV or 500/220 kV and 220/66 kV transformers at SYTS and transfer load from KTS to SYTS.

4. 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.

5. Embedded generation, connected to the KTS B(3,4), may substitute capacity augmentations.

Preferred network option(s) for alleviation of constraints at KTS(B1,2,5) and KTS(B3,4)

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 KTS to alleviate import constraints, it is proposed to upgrade all three transformers at KTS (B1,2,5), install additional transformation capacity at KTS B(3,4) and transfer 66 kV exits from KTS B(1,2,5) to KTS B(3,4) group. Powercor and Jemena commenced a Regulatory Investment Test for Transmission (RIT-T) by publishing a Project Specification Consultation Report (PSCR) in June 2025. The next report of the RIT-T, the Project Assessment Draft Report (PADR) is expected to be published during the first quarter of 2026.

Based on the current forecasts, commissioning of the preferred network option by 2029 would be economically justified. In addition to these works, it is possible that further augmentation work involving a combination of the above options may also be required, subject to the actual realisation of block loads.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

Keilor Terminal Station (B125 transformer group)

Detailed Import and Export Limitation data

Distribution Businesses supplied by this station: JEN (78%), Powercor (22%)

Station operational rating (N elements in service): 563 MVA

Summer N-1 Station Import Rating: 370 MVA **Winter N-1 Station Import Rating:** 425 MVA

Summer N-1 Station Export Rating: 300 MVA **Winter N-1 Station Export Rating:** 300 MVA

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	375.3	427.1	472.1	509.5	572.4	661.6	736.5	810.9	868.6	907.1
50th percentile Winter Maximum Demand (MVA)	327.1	384.2	438.0	481.5	550.8	644.7	722.7	798.9	857.3	898.5
10th percentile Summer Maximum Demand (MVA)	424.1	476.3	522.7	559.8	623.1	712.8	788.2	863.5	920.8	959.0
10th percentile Winter Maximum Demand (MVA)	355.9	413.5	467.9	511.7	581.4	675.7	753.8	830.1	888.5	929.8
N energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	6.2	3598.9	33252.9	102984.2	186500.4	260697.9
N hours at risk at 50% percentile demand (hours)	0.0	0.0	0.0	0.0	0.8	155.3	735.3	1496.8	2158.3	2635.8
N energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	145.5	11253.2	57911.9	148207.1	248885.3	335750.5
N hours at risk at 10% percentile demand (hours)	0.0	0.0	0.0	0.0	7.0	356.0	1055.5	1894.8	2618.5	3146.3
N-1 energy at risk at 50% percentile demand (MWh)	3.2	175.1	5859.8	27364.0	105924.5	301582.1	515443.8	745155.1	919602.9	1031937.4
N-1 hours at risk at 50th percentile demand (hours)	1.0	11.0	306.0	853.0	1997.5	3696.0	4776.5	5565.5	5638.8	5580.5
N-1 energy at risk at 10% percentile demand (MWh)	130.2	2008.0	20241.5	57979.5	167526.2	404002.9	637075.4	873875.3	1043154.3	1146843.1
N-1 hours at risk at 10th percentile demand (hours)	4.8	116.5	705.5	1406.3	2718.3	4414.8	5406.5	5801.8	5715.0	5393.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.02	1.14	38.09	177.87	694.70	5559.14	36603.27	107827.69	192477.84	267405.52
Expected Unserved Energy at 10th percentile demand (MWh)	0.85	13.05	131.57	376.87	1234.45	13879.23	62052.92	153887.32	255665.84	343205.01
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.04M	$1.49M	$6.95M	$27.14M	$217.20M	$1430.11M	$4212.89M	$7520.22M	$10447.69M
Expected Unserved Energy value at 10th percentile demand	$0.03M	$0.51M	$5.14M	$14.72M	$48.23M	$542.27M	$2424.44M	$6012.47M	$9989.02M	$13409.22M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.01M	$0.18M	$2.58M	$9.28M	$33.47M	$314.72M	$1728.41M	$4752.76M	$8260.86M	$11336.15M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. 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 2.65 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 VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

Keilor Terminal Station (B34 transformer group)

Detailed Import and Export Limitation data

Distribution Businesses supplied by this station: JEN (42%), Powercor (58%)

Station operational rating (N elements in service): 346 MVA

Summer N-1 Station Import Rating: 341 MVA **Winter N-1 Station Import Rating:** 361 MVA

Summer N-1 Station Export Rating: 300 MVA **Winter N-1 Station Export Rating:** 300 MVA

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	243.0	251.9	294.2	372.4	450.9	553.4	667.1	760.9	835.7	890.6
50th percentile Winter Maximum Demand (MVA)	237.5	250.5	298.7	382.0	466.0	573.1	690.3	786.3	863.4	921.7
10th percentile Summer Maximum Demand (MVA)	266.9	276.3	318.5	396.7	474.9	577.8	692.0	785.8	860.9	915.9
10th percentile Winter Maximum Demand (MVA)	235.4	248.4	296.7	380.1	464.0	570.9	687.7	784.0	861.2	919.4
N energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	543.6	20844.1	105066.3	290962.7	509741.4	721024.5	893999.0
N hours at risk at 50% percentile demand (hours)	0.0	0.0	0.0	50.5	547.8	1695.3	3230.8	4613.0	5443.5	5944.3
N energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	650.5	21036.8	109368.7	302174.2	527382.8	742791.4	918801.3
N hours at risk at 10% percentile demand (hours)	0.0	0.0	0.0	55.3	558.0	1787.3	3345.3	4701.8	5553.0	6157.3
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	324.9	2833.7	8466.1	15826.9	22192.0	26117.5	28722.4
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	25.5	51.5	101.0	134.3	114.3	100.3	140.8
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	336.8	2928.5	9005.6	16460.2	22763.2	26796.8	29523.3
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	22.0	59.8	134.5	149.5	139.5	123.8	86.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	545.01	20856.34	105102.97	291031.24	509837.52	721137.66	894123.46
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	651.99	21049.46	109407.74	302245.55	527481.47	742907.47	918929.20
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$24.11M	$922.74M	$4650.03M	$12875.98M	$22556.53M	$31905.00M	$39558.34M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$28.85M	$931.28M	$4840.48M	$13372.13M	$23337.15M	$32868.15M	$40655.81M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$25.53M	$925.30M	$4707.16M	$13024.82M	$22790.72M	$32193.94M	$39887.58M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. 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 2.65 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 VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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^{th} and 10^{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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

KERANG TERMINAL STATION (KGTS) 66kV & 22kV

Kerang Terminal Station (KGTS) 66 kV and 22 kV consist of three 35 MVA 235/66/22 kV transformers and is the main source of supply for 18,766 customers in Kerang and the surrounding area. The station supply area includes Kerang, Swan Hill, Gannawarra and Cohuna.

Embedded generation

A total of 157 MW of embedded generation capacity is installed or proposed to be installed on the Powercor distribution systems connected to KGTS 66 kV & 22 kV. It consists of:

- around 35 MW of rooftop solar PV, which includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW; and
- around 122 MW of large-scale embedded generation.

The following table lists the registered embedded generators (>5 MW) that are installed or proposed to be installed on the Powercor network connected to KGTS 66 kV & 22 kV:

Site name	Status	Technology Type	Nameplate capacity (MW)
Gannawarra Solar Farm	Existing Plant	Solar	50
Swan Hill Solar Farm	Existing Plant	Solar	14.4
Cohuna Solar Farm	Existing Plant	Solar	27.3
Kerang Solar Plant	Proposed	Solar	30

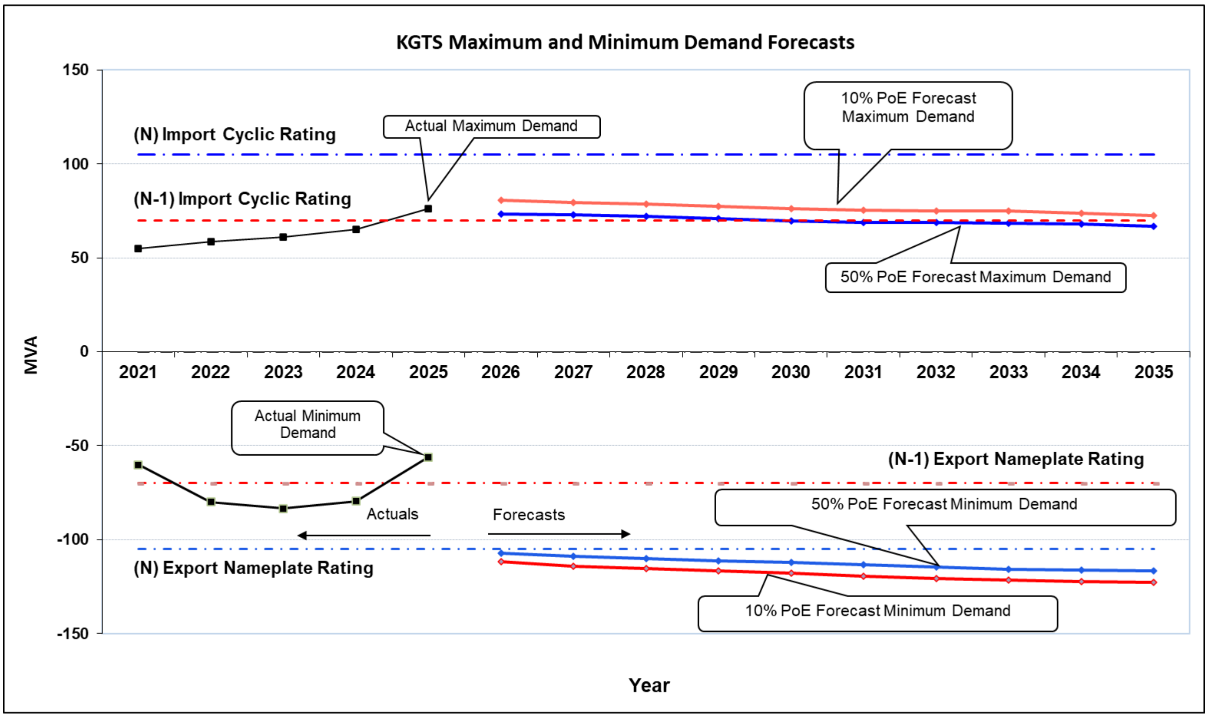
Magnitude, probability and impact of constraints

KGTS 22 & 66 kV maximum demand reached 75.7 MW (76.2 MVA, 66 kV and 22 kV networks) in summer 2025. Due to the input of generation connected to the station, reverse power flows occur during low load periods. The minimum demand at KGTS 66 kV & 22 kV reached -55.5 MW (-56.1 MVA) in March 2025.

The graph below shows the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at 40°C ambient temperature.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



It is estimated that:

- For 2 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.
- The station power factor at the time of maximum demand is 0.99.

In relation to minimum demand, it is estimated that:

- For 10 hours per year, 95% of the minimum demand is expected to be reached.
- The station power factor at the time of minimum demand is 0.99.

The above graph shows that there is insufficient capacity at the station to supply all expected maximum demand at the 10th percentile temperature over the forecast period, with one transformer out of service. However, the annual volume of expected unserved energy at the 10th percentile temperature is low (at less than 0.21 MWh), so augmentation or other corrective action to alleviate import constraints would not be economically justified over the next ten years.

The graph also shows that by 2025, for the 50th and 10th percentile minimum demand forecasts, there is expected to be insufficient export capability to enable all embedded generation to be exported, even with all transformers in service. For an outage of one transformer in 2035, 53 MVA of generation is at risk of curtailment (equating to an expected volume of generation curtailment of 359.1 MWh). In these circumstances, the cost of any augmentation to increase export capacity would either be met by the connecting generator(s) or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits. If it is uneconomic for augmentation to be undertaken, the need for and suitability of a generation runback scheme will be investigated.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

Kerang Terminal Station
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

	MVA	
Nameplate rating with all plant in service	105	via 3 transformers (summer)
Summer N-1 Station Import Rating:	70	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	70	
Summer N-1 Station Export Rating:	70	[See Note 7]
Winter N-1 Station Export Rating:	70	[See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	73.5	72.9	72.1	71.0	69.8	69.0	68.7	68.5	67.9	66.6
50th percentile Winter Maximum Demand (MVA)	71.3	70.7	69.8	68.7	67.5	67.0	66.9	66.6	65.7	64.4
10th percentile Summer Maximum Demand (MVA)	80.5	79.6	78.7	77.5	76.1	75.3	75.0	74.8	74.0	72.6
10th percentile Winter Maximum Demand (MVA)	78.8	78.2	77.3	76.0	74.7	74.2	74.1	73.8	72.7	71.3
N-1 energy at risk at 50% percentile demand (MWh)	2.8	2.0	1.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 50th percentile demand (hours)	1.5	1.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy at risk at 10% percentile demand (MWh)	32.0	26.1	20.2	13.7	8.8	6.9	6.5	6.0	4.1	2.0
N-1 hours at risk at 10th percentile demand (hours)	8.0	7.0	6.0	4.5	2.5	2.0	2.0	2.0	1.5	1.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy at 10th percentile demand (MWh)	0.21	0.17	0.13	0.09	0.06	0.05	0.04	0.04	0.03	0.01
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.01M	$0.01M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	111.9	114.0	115.5	116.7	117.8	119.3	120.5	121.6	122.3	122.7
Maximum generation at risk under N-1 (MVA)	41.9	44.0	45.5	46.7	47.8	49.3	50.5	51.6	52.3	52.7
N-1 energy curtailment (MWh)	9390.4	10242.4	10955.1	11445.9	11944.3	12683.4	13384.2	13979.4	14293.9	14462.2
Expected volume of export energy constrained (MWh)	92.9	120.7	149.6	173.0	198.5	237.7	279.2	319.5	344.4	359.1

Notes:
1. “N-1” means station output capability rating with outage of one transformer. The summer 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.

5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

MALVERN 22 kV TERMINAL STATION (MTS 22 kV)

MTS 22 kV is the source of supply for over 12,700 customers in Burwood, Ashwood, Glen Iris, Mount Waverley, and Surrey Hills.

Embedded generation

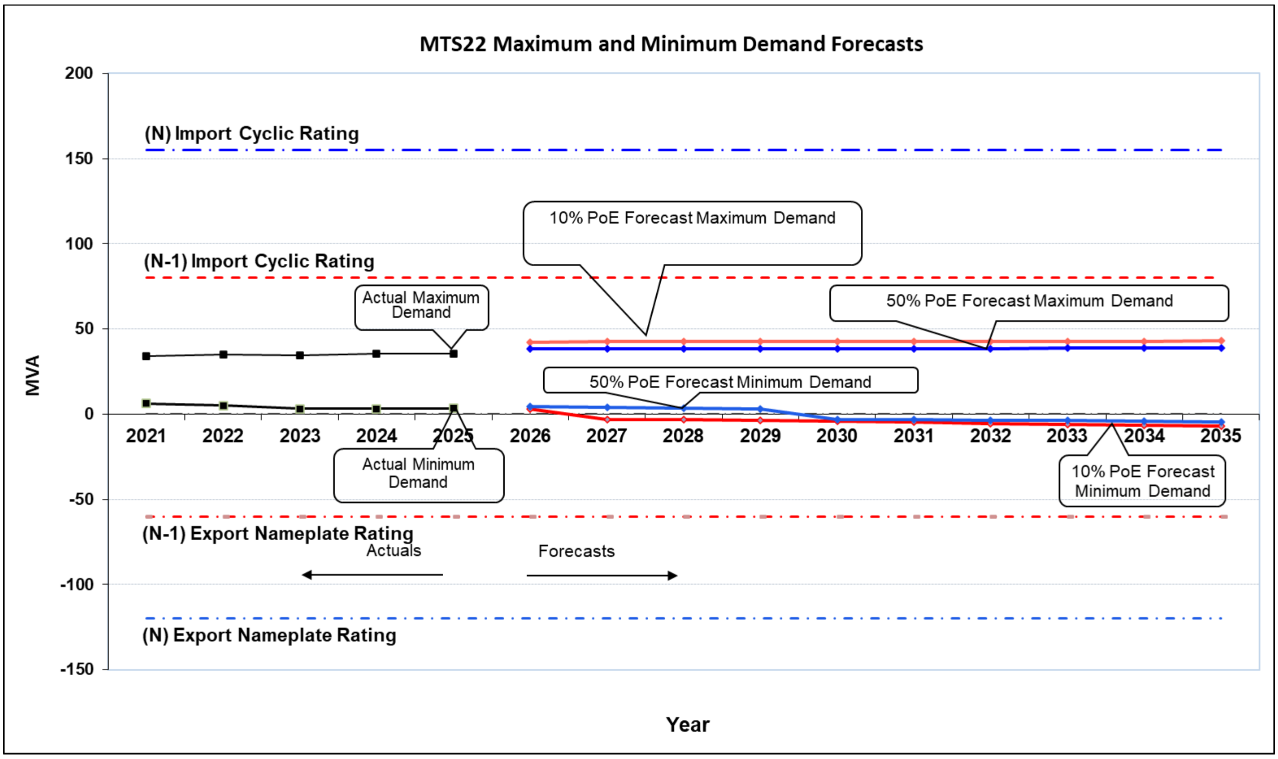
About 14.6 MW of rooftop solar PV is installed within the distribution system connected to MTS 22 kV. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW. There are no embedded generation units over 1 MW connected at MTS 22 kV.

Magnitude, probability, and impact of constraints

MTS 22 kV is a summer critical terminal station. The maximum demand in summer 2025 was 35.3 MW (35.4 MVA).

The graph below shows the historical demand, the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational N import and export ratings (all transformers in service) and the (N-1) import and export ratings at 40°C ambient temperature.

The export ratings on the chart reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

The N import rating on the graph indicates the maximum demand 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 shows that with one transformer out of service, the maximum demand at MTS 22 kV will remain well within the (N-1) station import rating over the next ten years. Therefore, the need for augmentation of MTS 22 kV to alleviate import constraints is not expected to arise over the next decade.

There is approximately 3 MVA of load transfer available at MTS 22 kV for summer 2025/26.

It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.99.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.93.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

MALVERN 66 kV TERMINAL STATION (MTS 66 kV)

MTS 66 kV is the main source of supply for over 85,0004 customers in Elsternwick, Caulfield, Carnegie, Malvern East, Ashburton, Chadstone, Oakleigh, Ormond, Murrumbeena, Hughesdale, and Bentleigh East.

Embedded generation

About 63.4 MW of rooftop solar PV is installed within the distribution system connected to MTS 66 kV (excluding the solar PV connected at MTS 22 kV). This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

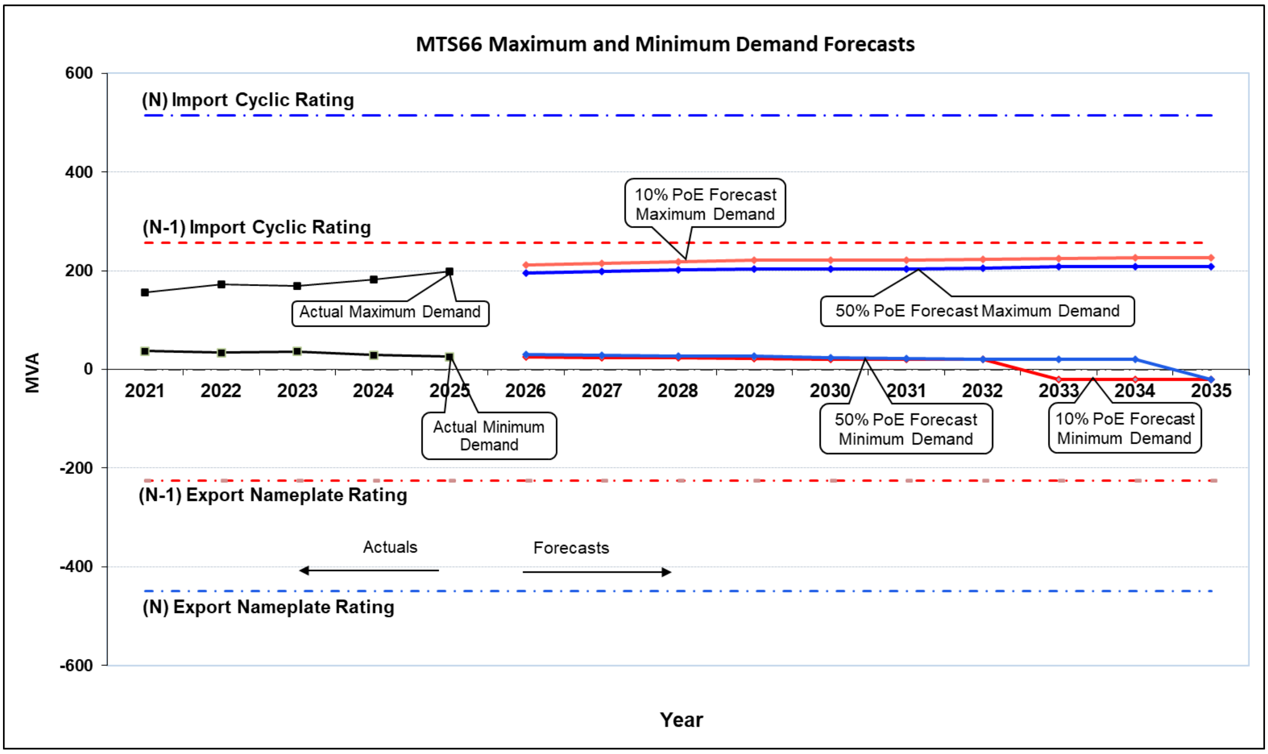
There are no embedded generation units over 1 MW connected at MTS 66 kV.

Magnitude, probability, and impact of constraints

MTS 66 kV is a summer critical terminal station. The maximum demand in summer 2025 was 193.9 MW (197.8 MVA). Note that the transformers at MTS 66 kV support the demand of both 66 kV and 22 kV networks ex MTS (refer also to the Risk Assessment for MTS 22 kV).

The graph below shows the historical demand, the 10th and 50th percentile maximum and minimum demand forecast together with the station's operational N import and export ratings (all transformers in service) and the (N-1) import and export ratings at 40°C ambient temperature.

The export ratings on the chart reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 6 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.90.

The N import rating on the graph indicates the maximum demand that can be supplied from MTS 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. There is approximately 15 MVA of load transfer available at MTS 66 kV for summer 2025/26.

The graph shows that with one transformer out of service, the 50% PoE and 10% PoE maximum demand at MTS is expected to remain within the (N-1) station import rating in this ten-year forecast period.

Based on the current forecasts, the need for augmentation of MTS 66 to alleviate import constraints is not expected to arise over the next decade.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

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.

Embedded generation

A total of 569.7 MW of embedded generation capacity is installed on the AusNet sub-transmission and distribution systems connected to MWTS. It consists of:

- 287.1 MW of large-scale embedded generation; and
- 282.6 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the embedded generators (>5 MW) that are installed on the AusNet network connected to MWTS.

Site name	Status	Technology Type	Nameplate capacity (MW)
Bald Hills Wind Farm	Existing Plant	Wind	106.6
Toora Wind Farm	Existing Plant	Wind	21
Wonthaggi Wind Farm	Existing Plant	Wind	12
Bairnsdale Power Station	Existing Plant	Gas	80
Traralgon Power Station	Existing Plant	Gas	10
Longford	Existing Plant	Gas	29.3
Thomson Dam	Existing Plant	Hydro	7.5

Magnitude, probability and impact of constraints

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

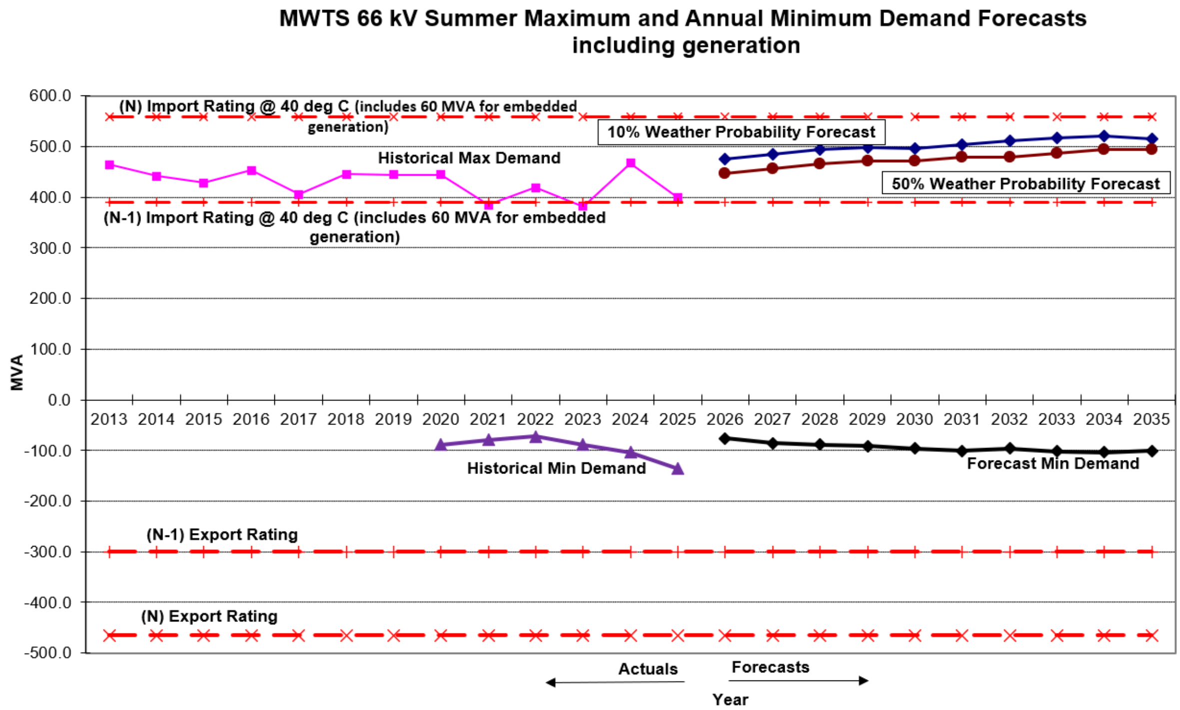
Maximum demand at MWTS 66 kV typically occurs in summer. The station reached a maximum demand of 396.9MW (398.5MVA) in summer 2024/25 which is lower than the highest annual maximum demand recorded to date occurred in the previous year (i.e. 467.3MVA). The maximum demand period is usually quite short and coincides with a few weeks of peak tourism from Christmas to early January along the east coast of Victoria. The maximum demand at MWTS 66 kV is forecast to increase over the ten-year planning horizon.

The assessment of the energy at risk at MWTS 66 kV needs to consider the significant levels of embedded generation that is connected into the MWTS 66 kV network and 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 106 MW Bald Hills Wind Farm. While a precise assessment is difficult due to the intermittency of the generation in the 66 kV loop, 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" import ratings shown on the graph below include the transformer capacity as well as the assumed 60 MVA contribution from embedded generation. For example, the 390 MVA "N–1" import rating includes the 330 MVA capacity of two 220/66 kV transformers and 60 MVA from embedded generation. The graph shows the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service plus 60 MVA from embedded generation) and the "N-1" import and export ratings at an ambient temperature of 40°C. The "N" import rating on the chart indicates the maximum load that can be supplied from MWTS 66 kV with all transformers in service. Summer maximum demand loading at MWTS is expected to exceed the station's "N-1" import rating for the entire 10-year planning period.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



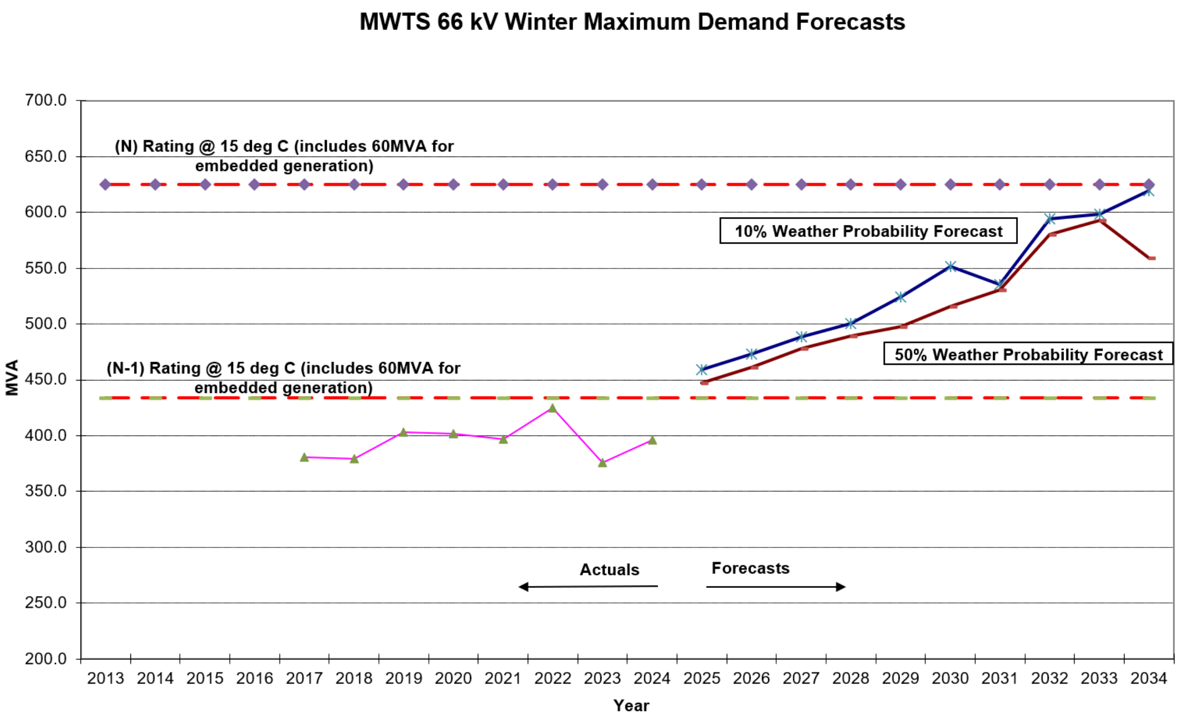
The station load has a power factor of 0.996 at maximum demand. MWTS 66 kV demand is expected to exceed 95% of the 50th percentile peak demand for 0.5 hours per annum.

In relation to minimum demand, it is estimated that:

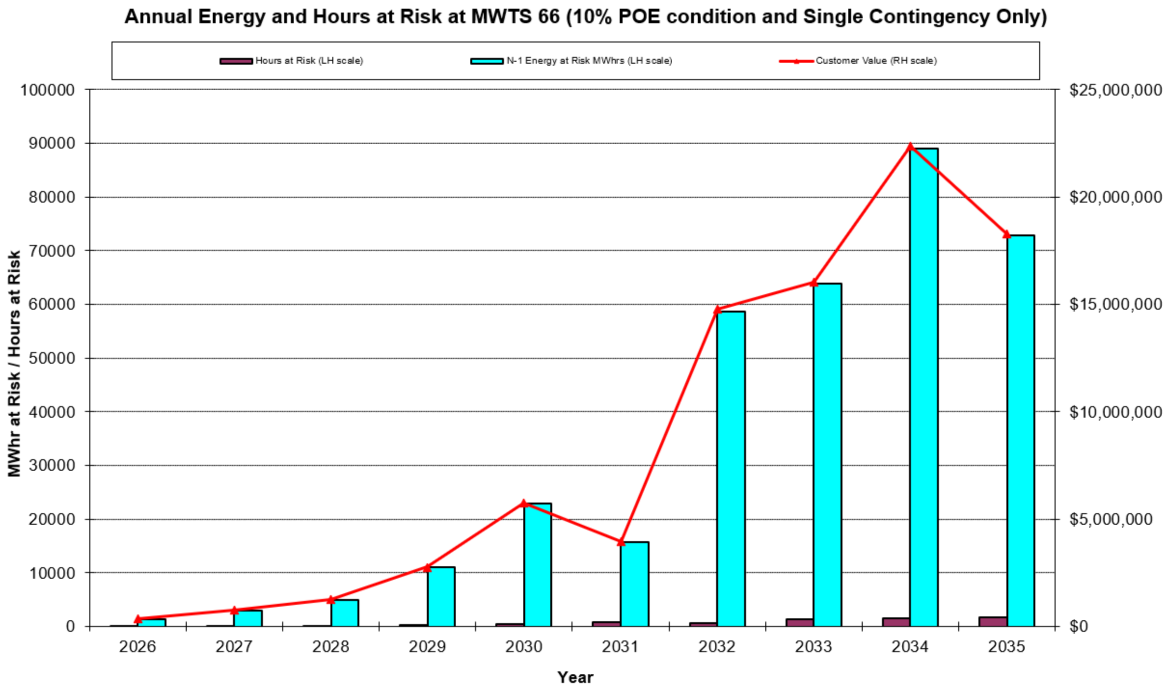
- For 2.75 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.90 at the time of minimum demand.

Minimum demand levels remained well within the station's operational "N" and "N-1" export ratings. This trend is expected to continue under both 50th percentile and 10th percentile minimum demand forecasts over the 10-year planning period.

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 during the summer period. The graph below shows the 10th and the 50th percentile winter maximum demand forecast together with the station's operational "N" import rating and "N-1" import rating. MWTS did not exceed its winter N-1 import rating this year, however, it is expected "N-1" import rating to be exceeded under both 50th percentile and 10th percentile winter maximum demand forecasts for the 10-year planning horizon while "N" import rating is not forecast to be exceeded for the planning horizon.



The bar chart below depicts the energy at risk with one transformer out of service for the 10th percentile maximum demand forecast, and the hours per year that the 10th percentile maximum demand forecast is expected to exceed the "N-1" import capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 10th percentile maximum demand forecast. The VCR at MWTS is $38,662 per MWh.



Key statistics relating to energy at risk and expected unserved energy for the year 2031 under "N-1" outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	12,619	$488 million
Expected unserved energy at 50th percentile maximum demand	83.6	$3.2 million
Energy at risk, at 10th percentile maximum demand forecast	15,802	$611 million
Expected unserved energy at 10th maximum percentile demand	104.7	$4 million
70/30 weighted expected unserved energy value (see below)	**89.9**	**$3.48 million**

Under the probabilistic planning approach[93], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[94]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[95].

93 See section 3.1.

94 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

95 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

Applying AEMO's approach, the weighted average cost of expected unserved energy in 2031 is $3.48 million.

It is noted that these estimates do not attribute any value to the prospective loss of generation that may be constrained. As already noted, for prospective embedded generation connections, the actual availability of export capacity will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

Possible impacts of a transformer outage on customers

If one of the 220/66 kV transformers at MWTS is taken off line during peak loading times and the "N-1" station import rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is operated by AusNet Transmission Group's TOC[96] to protect the connection assets from overloading[97], 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.

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 network import constraint:

1. Embedded generation: A feasible option may be to contract network support services from network support service provider/s (existing embedded generators) in the area. Availability of embedded generation network support over the ten-year planning horizon will lessen the need for network augmentation.

2. Install a fourth 220/66 kV transformer at MWTS: Installation of a 4th transformer at MWTS is a technically feasible option.

3. Establish a new 220/66 kV terminal station between MWTS and CBTS (Cranbourne Terminal Station). A new terminal station around Nar Nar Goon area could address energy at risk of both MWTS and CBTS. 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.

4. Installation of Power Factor Correction Capacitors: As the station is currently running with a power factor of around 0.996 at the summer peak, the use of additional capacitors to further improve the power factor and to reduce the MVA loading on the transformers will provide only marginal benefits.

Preferred network option for alleviation of constraints

An estimate of the annualised cost of installing a fourth transformer at MWTS has not yet been completed, but it is likely the expected value of unserved energy will exceed the annualised cost of the fourth transformer from 2031. In view of this, network and non-network solutions

96 Transmission Operation Centre.

97 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.

will be assessed using the RIT-T process to determine the preferred option to alleviate the identified constraints over the planning horizon.

It is expected that runback schemes may also be required to manage network constraints for operation of newly connected embedded generation over the ten-year planning horizon.

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.

MORWELL TERMINAL STATION 66kV (MWTS 66)
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

Normal import cyclic rating with all plant in service	558	MVA via 3 transformers and embedded generation
Summer import N-1 Station Rating	390	MVA via 2 transformers and embedded generation
Winter import N-1 Station Rating	434	MVA via 2 transformers and embedded generation
Normal export rating with all plant in service	465	MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	300	MVA [See Note 7 below for interpretation of Export rating]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	446.4	455.8	466.2	470.5	471.3	478.9	479.7	487.0	494.2	494.0
50th percentile Winter Maximum Demand (MVA)	461.1	477.9	489.4	497.3	516.0	530.6	580.3	593.0	558.9	591.8
10th percentile Summer Maximum Demand (MVA)	475.2	485.2	494.0	498.6	495.8	503.5	511.5	516.2	521.0	514.6
10th percentile Winter Maximum Demand (MVA)	473.0	488.6	500.2	523.9	551.2	535.5	594.3	598.7	619.3	606.7
N - 1 energy at risk at 50th percentile demand (MWh)	433	1,365	2,581	3,766	7,632	12,619	43,536	55,743	27,653	54,854
N - 1 hours at risk at 50th percentile demand (hours)	38.7	90.5	152.4	200.7	328.1	478.9	1,108.6	1,310.4	853.4	1,316.6
N - 1 energy at risk at 10th percentile demand (MWh)	1,393	2,982	5,026	11,017	22,990	15,802	58,751	63,897	89,073	72,790
N - 1 hours at risk at 10th percentile demand (hours)	51.7	102.8	191.7	272.4	451.5	779.4	617.6	1,430.4	1,519.0	1,787.5
N and N-1 Expected Unserved Energy at 50th percentile demand (MWh)	2.9	9.0	17.1	24.9	50.6	83.6	288.4	369.3	183.2	363.4
N and N-1 Expected Unserved Energy at 10th percentile demand (MWh)	9.2	19.8	33.3	73.0	152.3	104.7	389.2	423.3	590.1	482.2
N and N-1 Expected Unserved Energy value at 50th percentile demand	$0.11M	$0.35M	$0.66M	$0.96M	$1.95M	$3.23M	$11.15M	$14.28M	$7.08M	$14.05M
N and N-1 Expected Unserved Energy value at 10th percentile demand	$0.36M	$0.76M	$1.29M	$2.82M	$5.89M	$4.05M	$15.05M	$16.37M	$22.81M	$18.64M
N and N-1 Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.18M	$0.47M	$0.85M	$1.52M	$3.13M	$3.48M	$12.32M	$14.90M	$11.80M	$15.43M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum demand (MVA)	-76.6	-85.8	-89.0	-91.2	-95.9	-100.6	-95.8	-102.1	-103.6	-101.0
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The summer 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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^{th} and 10^{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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

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

The station has two 50 MVA 220/66 kV transformers with one transformer in service and the other available as a hot spare.

If the in-service 220/66 kV B2 transformer fails, the 66 kV network at MBTS 66 switchyard can be reconfigured to switch in the B1 hot spare transformer. It is estimated that the B1 transformer can be brought into service in a little as 4 hours, or up to 48 hours in worst case scenarios with unfavourable weather conditions. AusNet is presently reviewing procedures to fast track the restoration time for the B1 transformer, in the case of a B2 transformer outage.

In the present operating arrangement, the N rating will be equal to the "N-1" rating (i.e. equal to the capacity of one transformer). Further, in the event of a B2 transformer outage, supply can also be taken from Clover Power Station and the 66 kV tie to Glenrowan Terminal Station via Myrtleford. The assessment of Clover Power Station's capability to maintain the 66 kV voltage in the loop is based on the historic availability of the plant.

Embedded generation

A total of 51.2 MW of embedded generation capacity is installed on the AusNet sub-transmission and distribution systems connected to MBTS. It consists of:

- 29 MW of large-scale embedded generation; and
- 22.2 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the registered embedded generators (>5 MW) that are installed on the AusNet network connected to MBTS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Clover Power Station	Existing Plant	Hydro	29

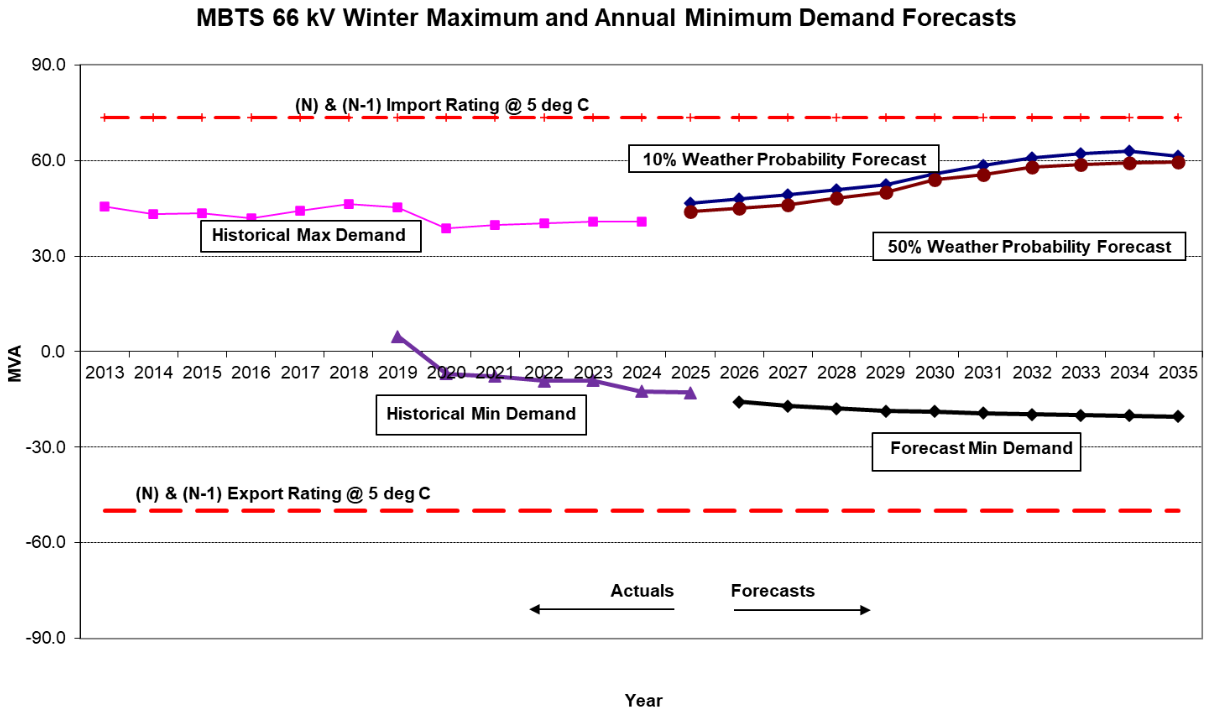
Magnitude, probability and impact of constraints

Maximum demand at MBTS occurs in Winter and is forecast to have a growth rate of 2.4% over the next 10 years at the 10th percentile forecast. Maximum demand at the station reached 46.7 MW in winter 2025. The recorded maximum demand in winter 2024 was 45.4 MW. The summer peak demand was around 30% lower than the winter peak demand.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N-1" import and export ratings (equal to "N" rating) at an ambient temperature of 5°C. Since the maximum demand forecast is increasing slowly, MBTS 66 kV is not expected to reach its "N-1" winter station import rating during the 10 year planning horizon.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



The station load has a power factor of 1.00 at maximum demand. The demand at MBTS 66 kV is expected to exceed 95% of the 50th percentile maximum demand for approximately 11.5 hours per annum.

In relation to minimum demand, it is estimated that:

- For 67 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of 0.94 at the time of minimum demand.

The above analysis does not include the possibility of loss of load for the 48 hours (maximum expected) 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. If Clover Power Station is available, it can generate around 29 MW and so any generation would also minimise the likelihood of the loss of customer load during a planned change over.

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 up to 48 hours.

The energy at risk for a major transformer outage[98] in this situation (taking account of the limited 66 kV tie line capability) is significant at around 12,662 MWh in winter 2026. However, given that the hot spare transformer can be made available within 48 hours, the expected outage duration in the case of a major transformer failure at MBTS is 48 hours (rather than 2.65 months). Accordingly, the probability of the transformer being unavailable in this particular case is only 0.0055%. The expected unserved energy at MBTS is therefore approximately 0.69 MWh in 2026 and this is estimated to have a value to consumers of approximately $27,518 (based on a value of customer reliability of $39,663/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 over $16 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.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

98 In this report, "major transformer outage" means an outage that has a mean duration of 2.65 months.

MOUNT COTTRELL TERMINAL STATION (MCTS) 132 kV

Mount Cottrell Terminal Station (MCTS) 132 kV is a proposed new terminal station and is expected to be commissioned in 2027. It will consist of two 350 MVA 220/132 kV transformers and will be the main source of supply for customers in the Mount Cottrell area. Powercor expects to shortly publish a RIT-T Project Specification Consultation Report in relation to the proposed MCTS.

Embedded generation

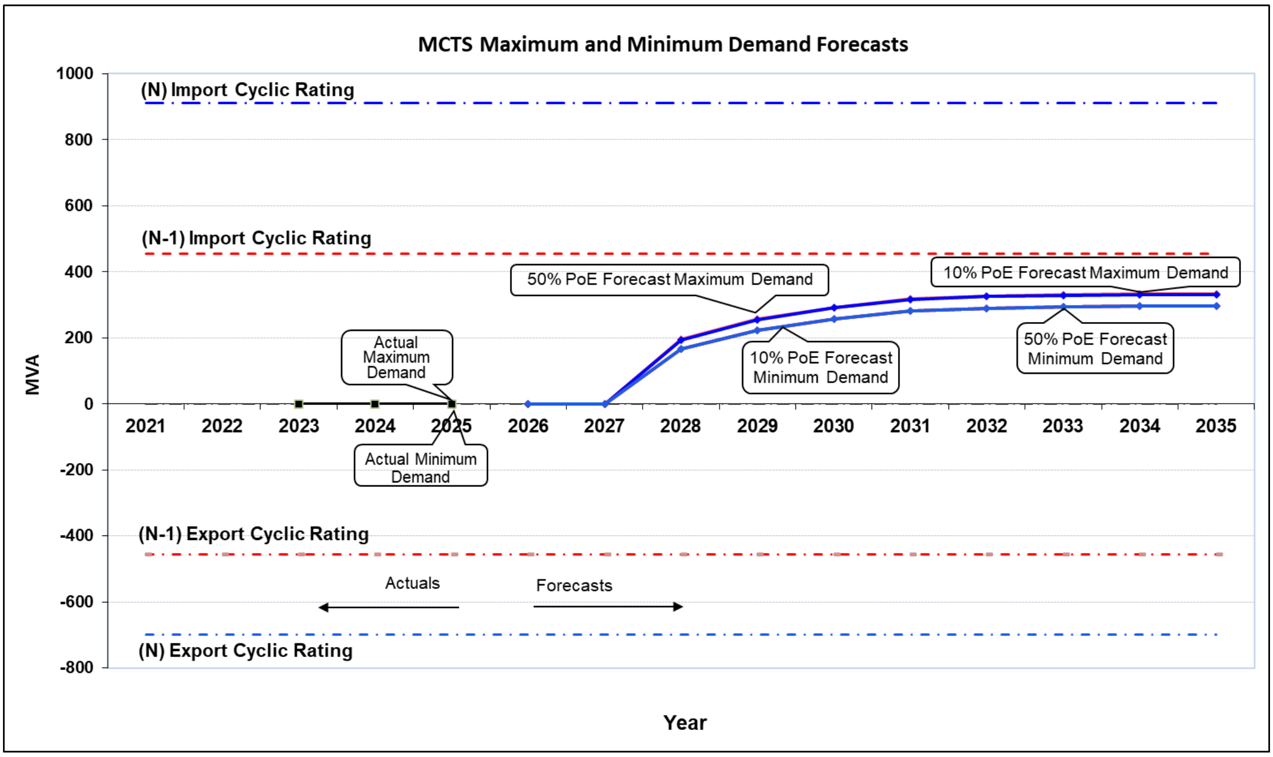
A total of 0 MW capacity of embedded generation is installed or proposed to be installed on the Powercor sub-transmission and distribution systems connected to MCTS.

Magnitude, probability and impact of constraints

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 40°C ambient temperature.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



It is estimated that for 2 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile forecast.

In relation to minimum demand, it is estimated that for 18 hours per year, 95% of the minimum demand is expected to be reached.

The graph shows there is sufficient capacity at the station to meet maximum demand 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 to alleviate import constraints is not expected to arise over the next ten years.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

RED CLIFFS TERMINAL STATION (RCTS) 22 kV

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 5,712 customers in Red Cliffs and the surrounding area. The station supply area includes Red Cliffs, Colignan and Werrimull.

Embedded generation

A total of 27.4 MW of embedded generation capacity is installed on the Powercor distribution system connected to RCTS 22 kV. It consists of:

- 7.4 MW of large-scale embedded generation; and
- 20 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

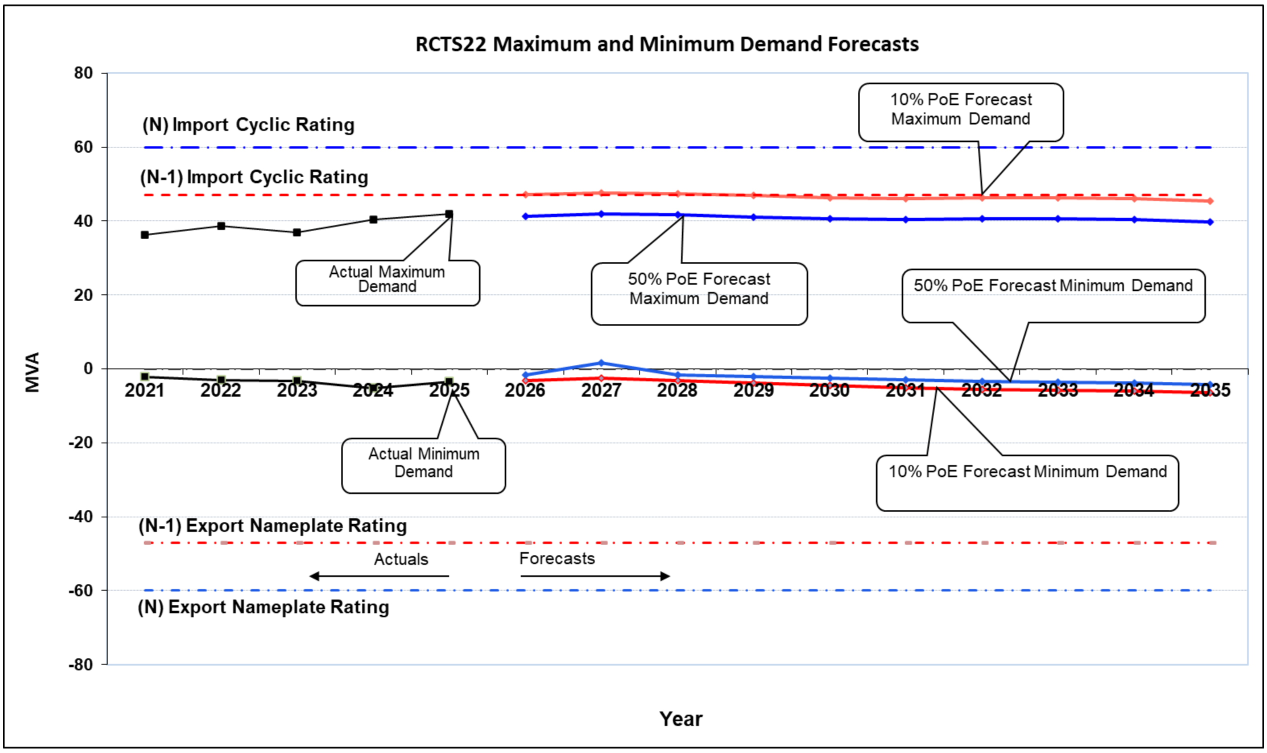
Magnitude, probability and impact of constraints

The maximum demand for the RCTS 22 kV network reached 40.2 MW (42.0 MVA) in summer 2025. The minimum demand at the station was -2.5 MW (-3.4 MVA) in October 2024.

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 (22 kV dropper rating), 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 maximum demand occurs in summer. The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings and the "N-1" import and export ratings at 40°C ambient temperature.

It should be noted that the ratings shown below are thermal ratings only. For some stations, export ratings (to accommodate reverse power flow) will be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the station's thermal rating. Work is underway to quantify the impacts of system limitations on station export ratings. Until that work is finalised, thermal ratings are shown.



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 transformer power factor at the peak time demand is 0.96 with both capacitor banks in service.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.74.

The graph shows there is sufficient capacity at the station to meet all expected maximum demand at the 50th and 10th percentile temperatures over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action to alleviate import constraints is not expected to arise over the next ten years.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

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 26,740 customers in Red Cliffs and the surrounding area. The station supply area includes Merbein, Mildura and Robinvale.

There is a rebuild project underway at RCTS to replace the B1, B2, L1 and L2 transformers scheduled to be completed by February 2029. The project will replace these transformers with two 150 MVA 220/66 kV transformers and two 20/33/49.5 MVA 66/22 kV transformers. Under the new configuration, RCTS will no longer be split into the 66 kV and 22 kV load groups as currently presented in the TCPR.

Embedded generation

A total of 243.5 MW of embedded generation capacity is installed on the Powercor sub-transmission and distribution systems connected to RCTS 66. It consists of:

- 191.5 MW of large-scale embedded generation; and
- 52 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the registered embedded generators that are installed on the Powercor network connected to RCTS 66 kV:

Site name	Status	Technology Type	Nameplate capacity (MW)
Karadoc Solar Farm	Existing Plant	Solar	90
Yatpool Solar Farm	Existing Plant	Solar	94
Robinvale Solar Farm	Existing Plant	Solar	7.5

Magnitude, probability and impact of constraints

RCTS 66 kV maximum demand occurs in summer. The maximum demand for the 66 kV network now supplied from the station reached 116.0 MW (120.0 MVA) in summer 2025. Due to the input of generation connected to the station, reverse power flows occur during low load periods. The minimum demand at RCTS 66 reached -160.0 MW (-167.0 MVA) in November 2024.

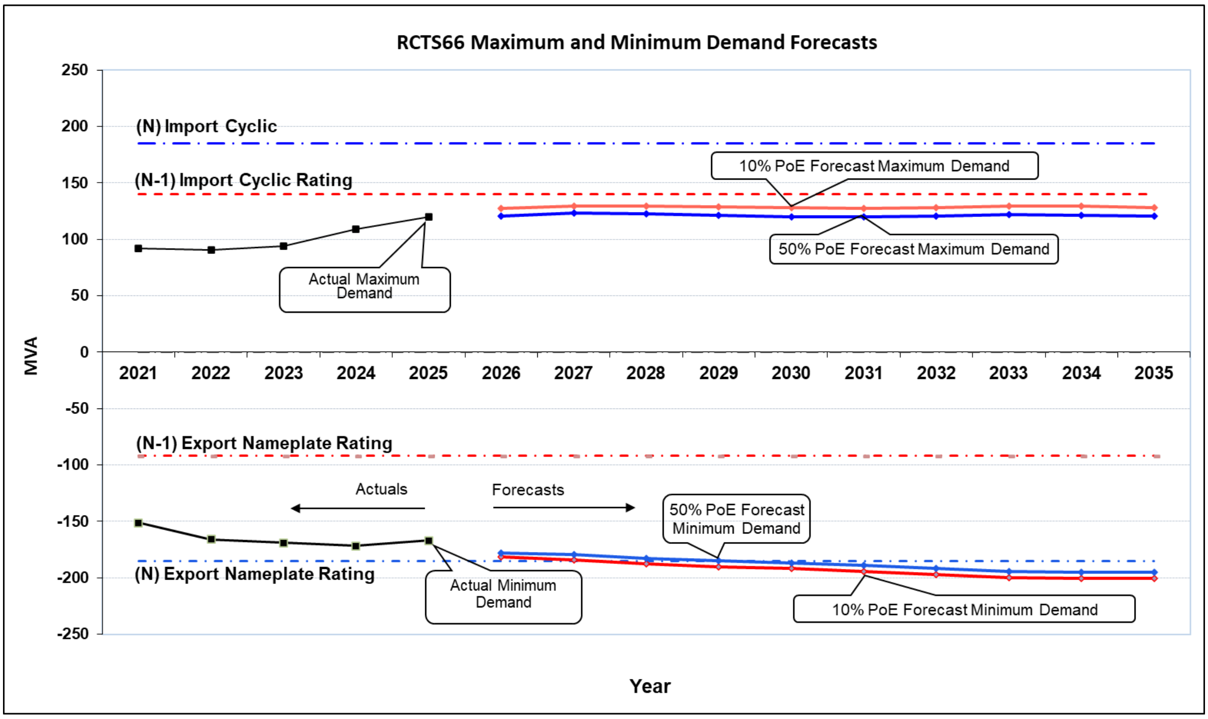
As noted in section 5.2 of this report, the connection of significant embedded generation to networks supplied from some terminal stations is expected to lead to reverse power flows that may necessitate a reduction in the ratings of some stations. RCTS 66 kV is one such station. In 2021 the station rating of RCTS 66 kV was reduced from cyclic to nameplate. This reduction is shown in the graph below.

The following observations and risk assessment are based on actual readings of power flow at the Terminal Station Connection points. It therefore accounts for the current load and generation combination.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and exports ratings at 40°C ambient temperature.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



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 power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 20 hours per year, 95% of the minimum demand is expected to be reached.
- The station power factor at the time of minimum demand is 0.96.

The chart shows there is sufficient capacity at the station to meet all expected maximum demand at the 10th and 50th percentile temperatures, over the forecast period even with one transformer out of service.

Therefore, the need for augmentation or other corrective action to alleviate import constraints is not expected to arise over the next ten years.

From 2025, at the 10th percentile minimum demand forecast, there is expected to be insufficient export capability to enable all embedded generation to be exported, even with all transformers in service. By the end of the forecast period in 2035, 109 MVA of embedded generation is at risk of curtailment for the loss of one transformer at RCTS 66 kV. This equates to 60,817 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 518 MWh.

In the event of a transformer outage at RCTS 66 kV the generators may need to reduce generation to avoid overloading the remaining transformer. AEMO has a constraint equation managing the terminal station transformer reverse loading. The generators are sent dispatch signals to reduce generation if the constraint equation binds. Any generation reduction is implemented through AEMO’s dispatch process.

Currently there is no planned augmentation at RCTS 66 kV for generation connections. Accommodation of additional generation, however, may require augmentation of transformer capacity, the cost of which would either be met by the connecting generator(s), or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

Red Cliffs Terminal Station 66 kV
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

	MVA	
Nameplate rating with all plant in service	185	via 3 transformers (summer)
Summer N-1 Station Import Rating:	140	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	140	
Summer N-1 Station Export Rating:	92	[See Note 7]
Winter N-1 Station Export Rating:	92	[See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	120.4	123.1	122.8	121.5	120.2	119.9	120.8	121.7	121.6	120.6
50th percentile Winter Maximum Demand (MVA)	123.0	123.5	123.1	122.2	121.3	121.9	123.2	124.0	123.4	122.4
10th percentile Summer Maximum Demand (MVA)	127.2	129.6	129.6	129.0	127.9	127.5	128.3	129.4	129.5	128.3
10th percentile Winter Maximum Demand (MVA)	129.6	130.1	130.0	129.2	128.6	129.4	131.0	132.0	131.5	130.4
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	181.7	183.9	187.4	190.0	191.8	194.4	197.1	199.5	200.5	200.5
Maximum generation at risk under N-1 (MVA)	89.7	91.9	95.4	98.0	99.8	102.4	105.1	107.5	108.5	108.5
N-1 energy curtailment (MWh)	47376.0	49114.3	51464.8	53002.1	54383.3	56578.8	58996.5	60878.1	61293.4	60817.1
Expected volume of export energy constrained (MWh)	314.1	325.6	343.4	358.1	373.1	404.4	450.1	505.1	526.3	518.1

Notes:
1. “N-1” means station output capability rating with outage of one transformer. The summer 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

RICHMOND TERMINAL STATION 22 kV (RTS 22 kV)

RTS 22 kV is a summer critical station equipped with two 75 MVA 220/22 kV transformers, providing supply to 6,576 customers in CitiPower's distribution network. The terminal station's supply area includes inner suburban areas in Richmond and surrounding areas. The station also provides supply to City Link and public transport railway substations east of the Central Business District.

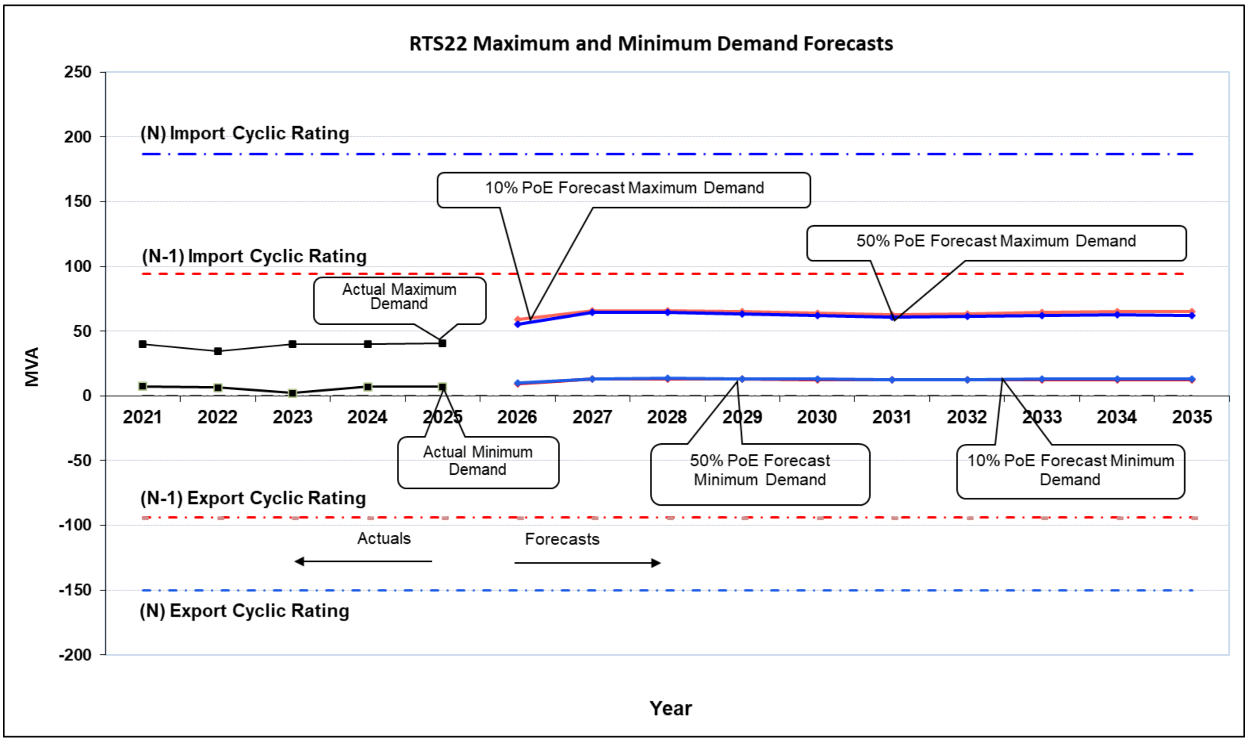
Embedded generation

About 1.6 MW of solar PV is installed on the CitiPower distribution system connected to RTS 22. This includes all the residential and small-commercial rooftop solar PV systems (<1 MW).

Magnitude, probability and impact of constraints

As part of AusNet Transmission Group's asset renewal program, the two existing 220/22 kV transformers were replaced by two new 75 MVA 220/22 kV transformers in 2018. The N and N-1 station import cyclic ratings were subsequently changed to approximately 190 MVA and 95 MVA respectively.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts for the next 10 years, together with the operational N and N-1 import cyclic ratings for RTS 22 kV.



It should be noted that the ratings shown below are thermal ratings only. For some stations, export ratings (to accommodate reverse power flow) will be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the station's thermal rating. Work is underway to quantify the impacts of system limitations on station export ratings. Until that work is finalised, thermal ratings are shown.

It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile summer forecast.
- The station load power factor at time of peak demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 40 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.90.

The graph indicates that the maximum demand at RTS 22 kV remains below its N-1 import rating over the ten-year planning period at 40°C ambient temperature. No limitations are noted for the minimum demand conditions over the ten-year planning period, so there is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon. Hence, no augmentation is planned at RTS 22kV to alleviate import or export constraints in the forward planning period.

RICHMOND TERMINAL STATION 66 kV (RTS 66 kV)

RTS 66 kV is a summer critical station consisting of three 225 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (86%) and United Energy (14%), providing supply to a total of 151,258 customers in the Eastern Central Business District and widespread inner suburban areas in the east and south-east of Melbourne.

Embedded generation

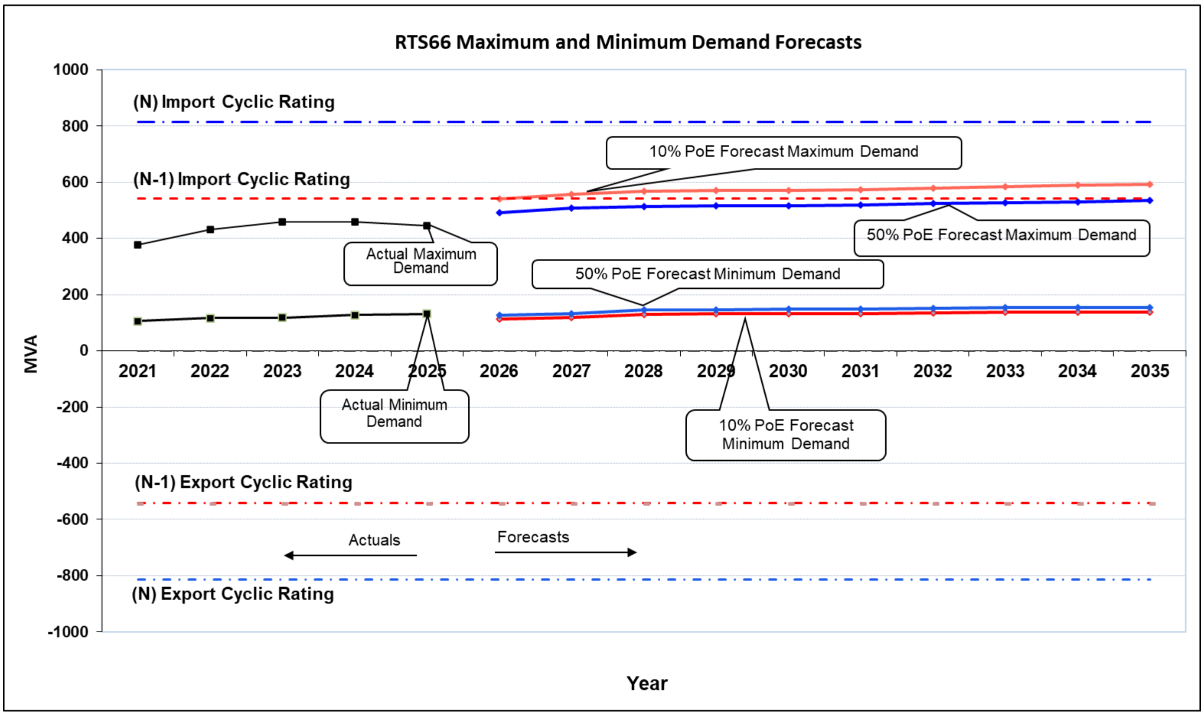
About 30 MW of solar PV is installed on the CitiPower distribution system and 16 MW on the United Energy distribution system, both of which are connected to RTS 66. This includes all the residential and small-commercial rooftop solar PV systems (<1 MW).

Magnitude, probability and impact of constraints

The maximum demand on the station reached 433.5 MW (446.4 MVA) in summer 2025.

RTS 66 is one of the terminal stations supplying the Melbourne CBD. To meet the Distribution Code of Practice requirements regarding security of supply to the Melbourne CBD, CitiPower has been undertaking works to re-configure the CBD 66 kV network to provide the required security to maintain supply from alternate supply points. This means that for an 'N-1' event in other parts of the CBD network, additional load can be switched onto RTS 66. This required additional import capacity must be reserved at the terminal station to ensure that CBD load can be supplied under any of the CBD security contingency arrangements. As per the current forecast, this reservation is only possible for the next 12 months.

The following graph shows recent actual and forecast maximum and minimum demand at the station. The station's (N) and (N-1) import cyclic ratings at 40°C are also shown. It should be noted that the ratings shown below are thermal ratings only. For some stations, export ratings (to accommodate reverse power flow) will be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the station's thermal rating. Work is underway to quantify the impacts of system limitations on station export ratings. Until that work is finalised, thermal ratings are shown.



It is estimated that:

- For 6 hours per year, 95% of peak demand is expected to be reached in a 50th percentile summer.
- The station load power factor at time of peak demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 80 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.91.

The graph indicates that the 50th percentile maximum demand at RTS 66 kV remains below its N-1 import rating over the ten-year planning period at 40°C ambient temperature. The load at risk during the 10th percentile temperature maximum demand conditions will be managed through load transfers within the sub-transmission network.

No limitations are noted for the minimum demand conditions over the ten-year planning period so there is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

Hence, no augmentation is planned at RTS 66 kV to alleviate import or export constraints in the forward planning period.

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 supplied by two 75 MVA 220/22 kV three-phase transformers. 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 (63%) and United Energy Distribution (37%).

Embedded generation

About 18.75 MW of rooftop solar PV is installed on the AusNet distribution system and about 19.87 MW of rooftop solar PV is installed on the UE distribution system connected to RWTS 22kV. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

There is no large-scale embedded generation installed on the AusNet and UE distribution systems connected to RWTS 22 kV.

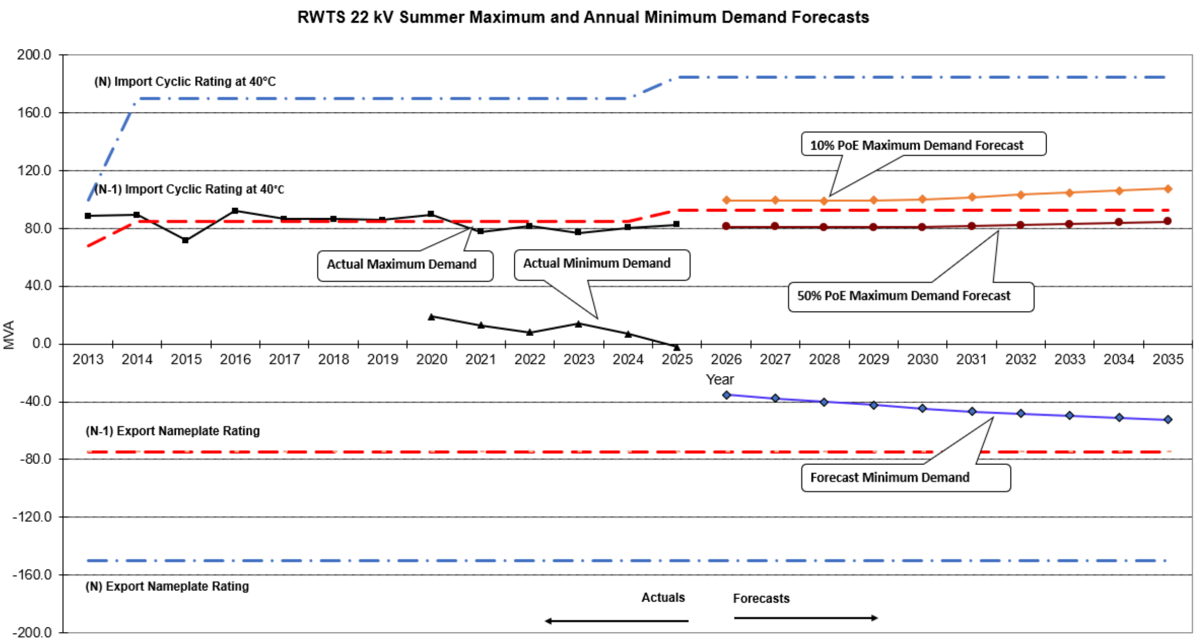
Magnitude, probability and impact of constraints

Maximum demand at the station occurs in summer. Summer maximum demand at RWTS 22 kV is forecast to increase slightly over the ten-year planning period. The 2024/25 summer maximum demand reached 82.5 MW (82.6 MVA), whereas the highest recorded maximum demand is 96.2 MVA, which occurred in summer 2008/09.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station's expected operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at an ambient temperature of 40°C.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



Maximum demand at RWTS 22 kV is expected to exceed 95% of the 50th percentile peak demand for 2.5 hours per annum. The station load has a power factor of 0.996 at maximum demand but load on the transformers has a power factor of 1.0 if all the 22 kV capacitors are switched in at the station.

In relation to minimum demand, it is estimated that:

- For 7 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of 0.94 at the time of minimum demand.

The graph indicates that the summer maximum demand at RWTS 22 kV remains below its “N” import rating throughout the 10-year planning period. The 50th percentile summer maximum demand is also not expected to exceed the station’s N-1 import rating; however, the 10th percentile summer maximum demand is expected to exceed the station’s N-1 import rating from the summer of 2025/26.

The winter maximum demand at RWTS 22 kV is not expected to reach the station’s “N” or “N–1” winter import rating during the ten-year planning horizon.

Key statistics relating to energy at risk and expected unserved energy for the year 2034/35 are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	0	$0
Expected unserved energy at 50th percentile maximum demand	0	$0
Energy at risk, at 10th percentile maximum demand forecast	38	$1.67 million
Expected unserved energy at 10th percentile maximum demand	0.17	$7,314
70/30 weighted expected unserved energy value (see below)	**0.05**	**$2,194**

Under the probabilistic planning approach[99], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[100]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[101]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034/35 is $2,194.

With minimal forecast energy at risk over the planning horizon, there is no augmentation planned to alleviate import constraints in the next ten years. Any risk will be managed through load transfers or other cost-effective operational action.

There is expected to be sufficient station export capability to accommodate all embedded generation output over 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.

99 See section 3.1.

100 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

101 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-pproach.ashx (aemo.com.au)

Ringwood Terminal Station 22 kV (RWTS 22 kV)

Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station:	AusNet Electricity Services (63%) United Energy (37%)
Installed Transformer Capacity	150 MVA
Normal import cyclic rating with all plant in service	185 MVA via 2 transformers (Summer peaking)
Summer import N-1 Station Rating	93 MVA [See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating	94 MVA
Normal export rating with all plant in service	150 MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	75 MVA [See Note 7 below for interpretation of Export rating]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	81.1	81.0	80.5	80.6	80.8	81.2	81.9	82.8	83.6	84.6
50th percentile Winter Maximum Demand (MVA)	76.1	76.4	78.4	80.1	82.0	84.3	90.1	93.6	96.6	99.4
10th percentile Summer Maximum Demand (MVA)	99.1	99.2	98.9	99.2	99.9	101.2	102.9	104.3	105.8	107.3
10th percentile Winter Maximum Demand (MVA)	81.9	82.7	83.9	86.7	89.1	90.9	96.5	101.2	104.7	107.7
N - 1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N - 1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N - 1 energy at risk at 10th percentile demand (MWh)	4	4	4	4	6	9	15	21	29	38
N - 1 hours at risk at 10th percentile demand (hours)	2	2	2	2	3	3	4	5	7	8
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.17
Expected Unserved Energy value at 50th percentile demand	$0.000M	$0.000M	$0.000M	$0.000M	$0.000M	$0.000M	$0.000M	$0.000M	$0.000M	$0.000M
Expected Unserved Energy value at 10th percentile demand	$0.001M	$0.001M	$0.001M	$0.001M	$0.001M	$0.002M	$0.003M	$0.004M	$0.006M	$0.007M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.000M	$0.000M	$0.000M	$0.000M	$0.000M	$0.001M	$0.001M	$0.001M	$0.002M	$0.002M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	-35.3	-37.6	-40.0	-42.1	-44.5	-46.6	-48.2	-49.5	-51.0	-52.4
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at a summer 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

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 northeast; 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 (76%) and United Energy (24%).

Embedded generation

Approximately 190 MW of rooftop solar photovoltaic (PV) capacity is installed on the AusNet distribution system, and around 44 MW is installed on the United Energy (UE) distribution system connected to the RWTS 66 kV network. These figures represent the aggregate capacity of residential and small-commercial rooftop PV systems rated below 1 MW.

A total of 7.1 MW capacity of large-scale embedded generation is installed on the AusNet and UE sub-transmission and distribution systems connected to RWTS 66 kV.

There are no embedded generators (>5 MW) that are installed on the AusNet or UE network connected to RWTS 66 kV.

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.

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.

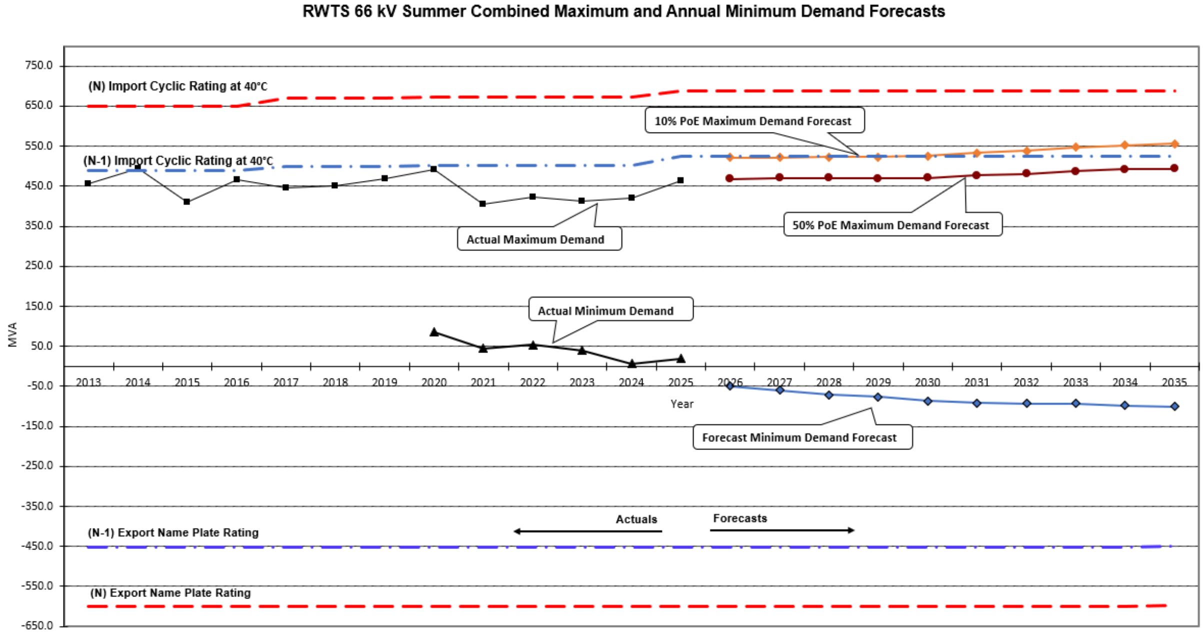
Given this configuration, maximum demand on the RWTS bus groups 1-3 and 2-4 must be always kept within the capabilities of their respective two transformers, otherwise load shedding may occur. For an unplanned transformer outage in any of the two RWTS bus groups, an auto close scheme will operate resulting in parallel operation of the three remaining transformers.

In late-2025, AusNet Transmission Group reviewed and updated the cyclic ratings of the RWTS transformers. As a result, the "N" summer cyclic rating (40°C) of Bus group 1-3 and Bus group 2-4 were increased to 332 MVA, from 330 MVA and 371 MVA from 355 MVA, respectively. The RWTS66 "N-1" summer cyclic rating (40°C) was also increased from 502 MVA to 526 MVA.

Combined Demand forecasts for RWTS 66 kV - Total Station Demand

The maximum demand on the station reached a record of 508 MW (516 MVA) in summer 2008/09 under extreme weather conditions. The recorded maximum demand in summer 2024/25 was 425.3 MW (432 MVA), which was lower than the summer 2008/09 station maximum demand.

The graph below depicts the 10th and 50th percentile total maximum and minimum demand forecasts together with the station's expected operational N import and export ratings (all transformers in service) and the (N-1) import and export ratings at 40°C ambient temperature.



The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown above therefore, provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

The graph indicates that the maximum demand at RWTS 66 kV remains below its N import rating throughout the 10-year planning period. The 50th percentile summer maximum demand is also not expected to exceed the station's N-1 import rating throughout the 10-year planning period. However, the 10th percentile summer maximum demand is expected to exceed the station's N-1 import rating starting from the summer of 2030/31.This risk will be monitored over the coming years to determine when action needs to be taken.

The combined winter maximum demand at RWTS 66 kV is not expected to reach the station's "N–1" winter import rating during the ten-year planning horizon.

The station load has a power factor of 0.98 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 2 hours per annum.

In relation to minimum demand, it is estimated that:

- For 8.5 hours per year, 95% of the minimum demand is expected to be reached.

- The station load has a power factor of -0.99 at the time of minimum demand.

Key statistics relating to energy at risk and expected unserved energy for the year 2034/35 are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	0	$0
Expected unserved energy at 50th percentile maximum demand	0	$0
Energy at risk, at 10th percentile maximum demand forecast	1.56	$64,217
Expected unserved energy at 10th percentile maximum demand	0.014	$567
70/30 weighted expected unserved energy value (see below)	**0.004**	**$172**

Under the probabilistic planning approach[102], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[103]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th percentile maximum demand forecasts under station "N-1" scenario. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[104]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034/35 is $19,265.

RWTS Bus groups 1-3 and 2-4: Summer Maximum Demand Forecasts

In addition to considering the station's total maximum 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.

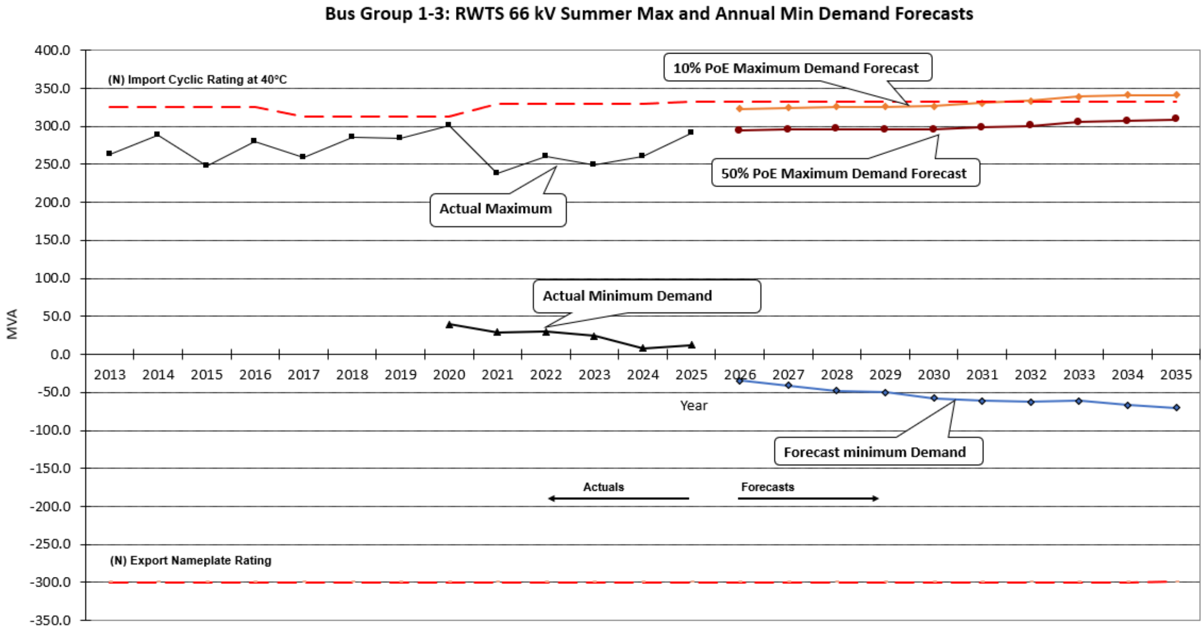
RWTS Bus group 1-3: Maximum demand at RWTS 66 kV bus group 1-3 occurs in summer. Based on the individual summer maximum demand forecasts for this bus group, with both transformers in service, i.e. under "N" conditions, the maximum demand under 50th percentile on this bus group is expected to remain below the limit. However, the 10th percentile forecast demand shows an exceedance of the "N" rating commencing from 2031/32 summer. When the demand exceeds the 10th percentile level, 22 kV load transfers would be utilised to manage system normal loading to within the terminal station's limits.

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).

102 See section 3.1.

103 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

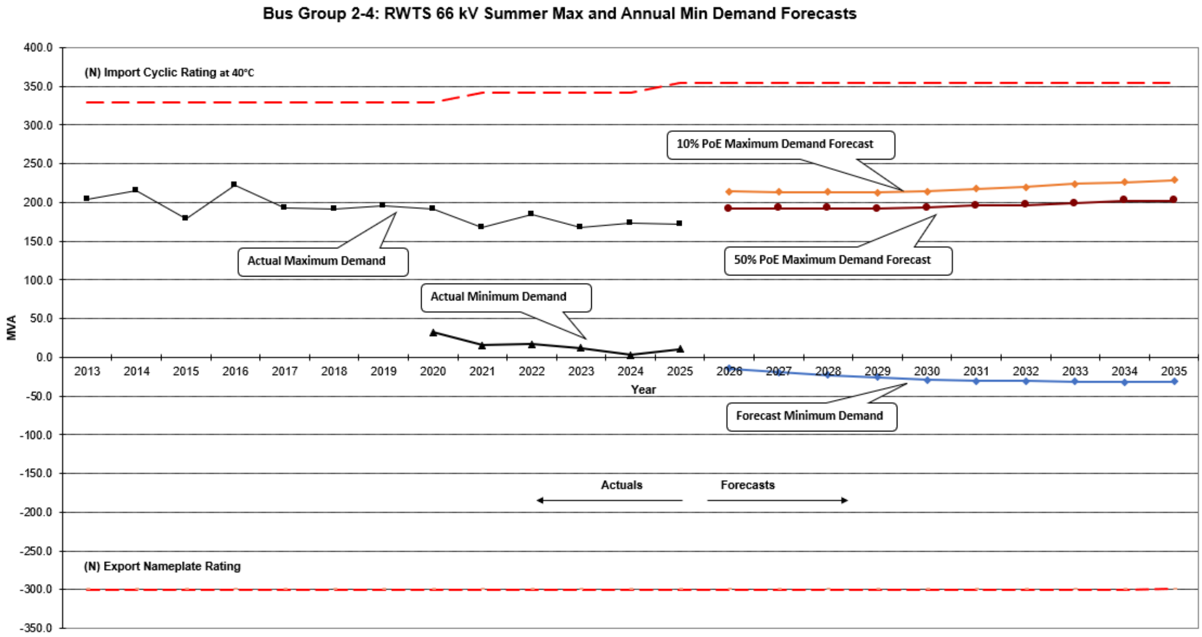
The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the bus group 1-3 “N” import and export ratings at an ambient temperature of 40°C.



RWTS Bus group 2-4: Like bus group 1-3, the maximum demand at RWTS 66 kV bus group 2-4 also occurs in summer. Based on the individual summer maximum demand forecasts for this bus group, with both transformers in service, i.e. under “N” conditions, the maximum 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 or load transfers being required to keep loading within import ratings on this bus group under normal operating conditions during summer or winter.

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 40°C.



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

Table 1: Detailed data: System normal maximum and minimum demand forecasts and limitations for RWTS 66

Table 2: Detailed data: System normal maximum and minimum demand forecasts and limitations for RWTS Bus Group 1-3

Table 5

RINGWOOD TERMINAL STATION 66kV (RWTS 66)

Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station:	AusNet Electricity Services (76%), United Energy (24%)
Summer import N Station Rating (MVA):	687 MVA [See Note 1 below for interpretation of N]
Summer import N-1 Station Rating (MVA):	547 MVA [See Note 2 below for interpretation of N-1]
Winter import N-1 Station Rating (MVA):	585 MVA
Export N-1 Station Rating	450 MVA [See Note 7 below for interpretation of Export rating]

Import	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
50th percentile Summer Maximum Demand (MVA)	467.9	470.3	471.0	469.5	471.1	477.3	480.3	487.1	492.5	494.0
50th percentile Winter Maximum Demand (MVA)	396.6	407.1	418.5	430.2	452.4	479.1	490.0	501.3	517.4	526.4
10th percentile Summer Maximum Demand (MVA)	521.4	521.9	522.6	522.4	524.8	532.7	537.7	547.6	552.1	555.4
10th percentile Winter Maximum Demand (MVA)	414.5	425.2	436.0	447.8	469.5	494.6	509.5	523.0	535.8	539.9
N - 1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N - 1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N - 1 energy at risk at 10th percentile demand (MWh)	0	0	0	0	0	0	0	0.01	0.58	1.56
N - 1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	0.28	0.48	0.62
Expected Unserved Energy at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
Expected Unserved Energy at 10th percentile demand (MWh)	0	0	0	0	0	0	0	0	0.005	0.014
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	-49.4	-60.2	-70.9	-76.0	-87.2	-91.8	-93.1	-92.6	-98.7	-101.0
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 6

RINGWOOD TERMINAL STATION 66kV Bus group 1-3 (RWTS 66)
Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station:	AusNet Electricity Services (76%), United Energy (24%)
Normal cyclic rating with all plant in service	332 MVA via 2 transformers (Summer 50%POE peaking)
Normal export rating with all plant in service	300 MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	See total station table.

Station: RWTS 66kV	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	294.1	295.8	296.1	295.4	295.6	298.4	300.9	305.8	306.8	308.9
50th percentile Winter Maximum Demand (MVA)	241.8	247.7	254.5	260.8	271.0	288.2	290.4	297.3	304.9	318.2
10th percentile Summer Maximum Demand (MVA)	322.9	324.7	325.6	325.7	326.4	330.6	333.3	339.1	341.0	341.5
10th percentile Winter Maximum Demand (MVA)	252.3	258.7	265.1	271.8	281.7	296.8	303.0	309.7	316.4	325.4
N energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N energy at risk at 10th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0.29
N hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0.28
Expected Unserved Energy at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
Expected Unserved Energy at 10th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum demand (MVA)	-34.7	-41.1	-47.7	-50.3	-57.9	-61.3	-62.5	-61.0	-66.8	-70.0
Maximum generation at risk under N-1 (MVA)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes:

1. "N" means the aggregated cyclic station output capability ratings of Bus group 1-3 and 2-4 when all 4 transformers in service.
2. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at a summer ambient temperature of 40 degrees Centigrade.
3. "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.
4. "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.
5. "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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.

6. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, weighted in accordance with the composition of the load at this terminal station.
7. 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)
8. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

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 77,024 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.

Embedded generation

A total of 504.5 MW of embedded generation capacity is installed or proposed to be installed on the Powercor sub-transmission and distribution systems connected to SHTS. It consists of:

- 352.5 MW of large-scale embedded generation, predominately solar farms; and
- 152 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems.

The following table lists the registered embedded generators (>5 MW) that are installed or proposed to be installed on the Powercor network connected to SHTS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Numurkah Solar Farm	Existing Plant	Solar PV	100
Girgarre Solar Farm	Approved project	Solar PV	76
Wunghnu Solar Farm	Approved project	Solar PV	75
Yarrawonga Hydro	Existing Plant	Hydro	9.5
Lancaster Solar Farm	Proposed	Solar PV	80
Carag Solar Farm	Proposed	Solar PV	12

Transformer replacement works at SHTS

AusNet Transmission Group is planning to replace two transformers (B2 and B3) at SHTS as part of its asset replacement program. The replacement project will be completed by 2029. During a planned outage for the replacement of a transformer, the reverse power flow at SHTS must be limited to 225 MVA (pre-contingent) to avoid overloading the remaining transformers should a transformer contingency occur.

Magnitude, probability and impact of constraints

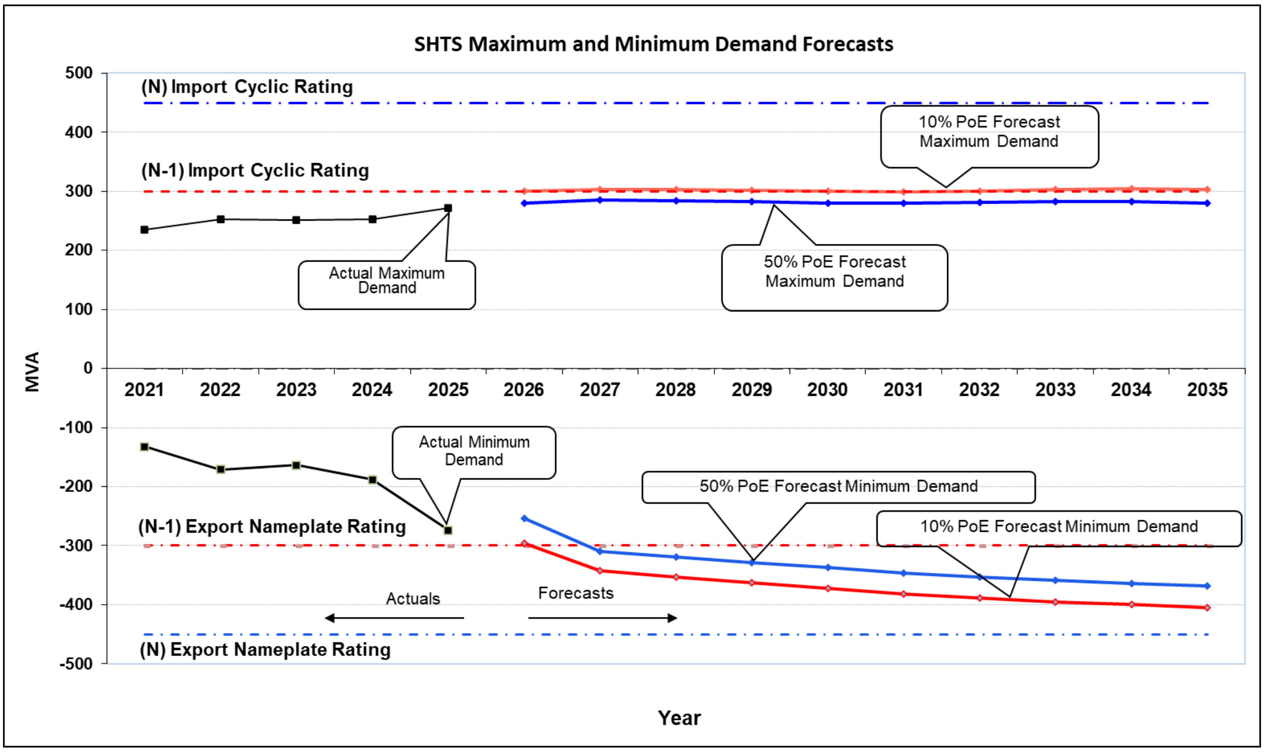
The following observations and risk assessment are based on actual readings of power flow at the Terminal Station Connection points. It therefore accounts for the present load and generation combination.

Maximum demand at SHTS occurs in summer. The maximum demand on the station reached 267.4 MW (272.3 MVA) in summer 2025. Due to the input of generation connected to the station, reverse power flows occur during low load periods. The minimum demand at SHTS reached -251.2 MW (-274.1 MVA) in March 2025.

The chart below depicts the 10th and 50th percentile maximum and minimum demand forecasts together with the station operational "N" import and export ratings (all transformers in service) and the "N−1" import and export ratings at 40°C ambient temperature.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



It is estimated that:

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

In relation to minimum demand, it is estimated that:

- For 48 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.92.

The chart shows there is sufficient capacity at the station to meet all expected maximum demand at the 50th percentile temperature, over the forecast period even with one transformer out of service. At the 10th percentile temperature, load at risk over the planning period is immaterial. Therefore, the need for augmentation or other corrective action to alleviate import constraints is not expected to arise over the next ten years.

With all transformers in service, there is expected to be sufficient station export capability to accommodate all forecast embedded generation output over the ten-year planning horizon. The graph above shows that an increasing volume of output from embedded generators connected downstream of SHTS is forecast to be at risk of being curtailed over the planning period. By the end of the period in 2035, approximately 105 MVA of embedded generation is at risk of curtailment for the loss of one transformer at SHTS. This equates to 1,581 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 10.5 MWh, which is immaterial from a transmission connection planning perspective.

The cost of any augmentation to accommodate additional embedded generation would either be met by the connecting generator(s) or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits. If it is uneconomic for augmentation to be undertaken, the need for and suitability of a generation runback scheme will be investigated.

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 150 MW 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 (71%) and Jemena Electricity Networks (29%).

The forecasts for each DB supplied from this station have been prepared using different approaches. Jemena has applied a forecasting methodology to include diversified non-committed block loads by applying ramping profiles, load realisation factors, and connections likelihood. The forecasts prepared by AusNet include only committed block loads, noting that there are significant block loads progressing through application processes. Non-network proponents should note that the use of non-committed block loads increases the uncertainty of the nature and timing of the augmentations.

In late 2025, AusNet Transmission Group reviewed and updated the cyclic ratings of the SMTS transformers, considering the rating limitations of the HV tap changers. As a result, the “N” summer cyclic rating (40°C) was increased to 519 MVA, from 500 MVA, while the “N-1” summer cyclic rating (40°C) increased to 259 MVA from 250 MVA. The “N” winter cyclic rating (15°C) was reduced to 543 MVA, down from 588 MVA, and the “N-1” winter cyclic rating (15°C) was reduced to 271 MVA, down from 294 MVA. Consequently, the winter energy-at-risk has increased due to the reduction in the station winter rating (both N and N-1 risk present).

Maximum demand at SMTS 66 kV occurs in summer. In 2024/25 the summer maximum demand reached 427.5 MW (434.8 MVA), which is the historical maximum for the station.

Embedded generation

About 204 MW of rooftop solar PV is installed on the AusNet distribution system and about 84.67 MW of rooftop solar PV is installed on the Jemena distribution system connected to SMTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

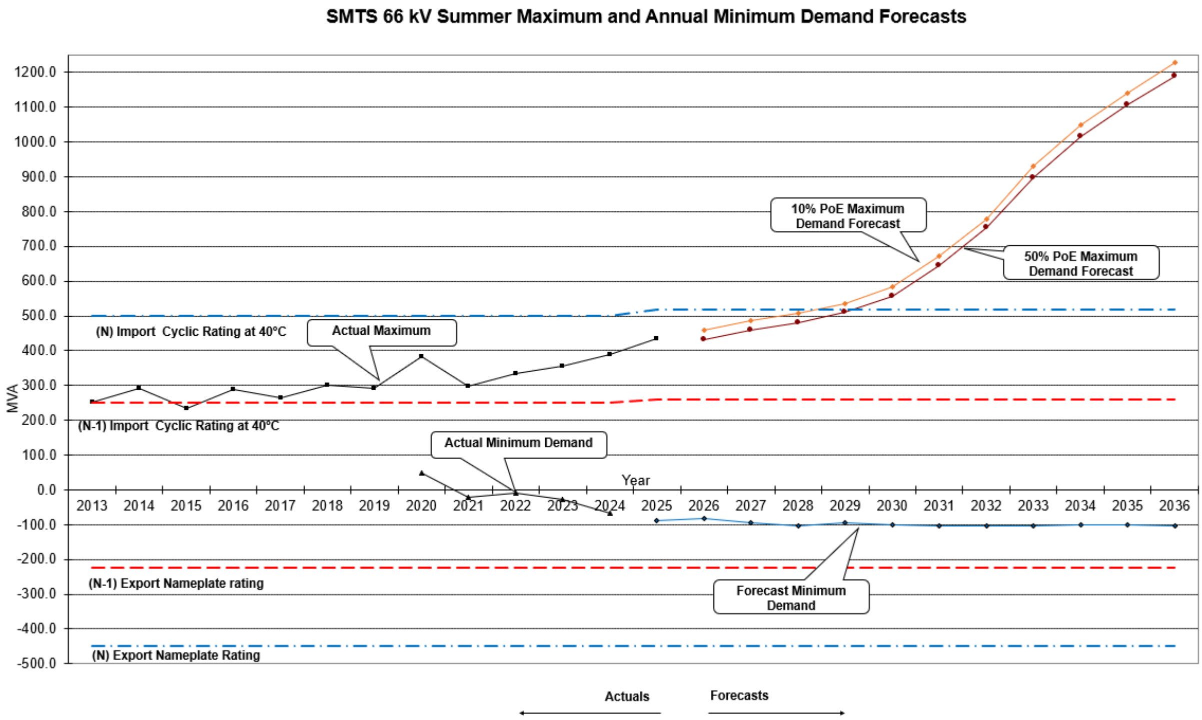
A total of 247.2 MW capacity of large-scale embedded generation is installed on the AusNet and Jemena sub-transmission and distribution systems connected to SMTS.

The following table lists the embedded generators (>5 MW) that are installed on the AusNet and Jemena networks connected to SMTS:

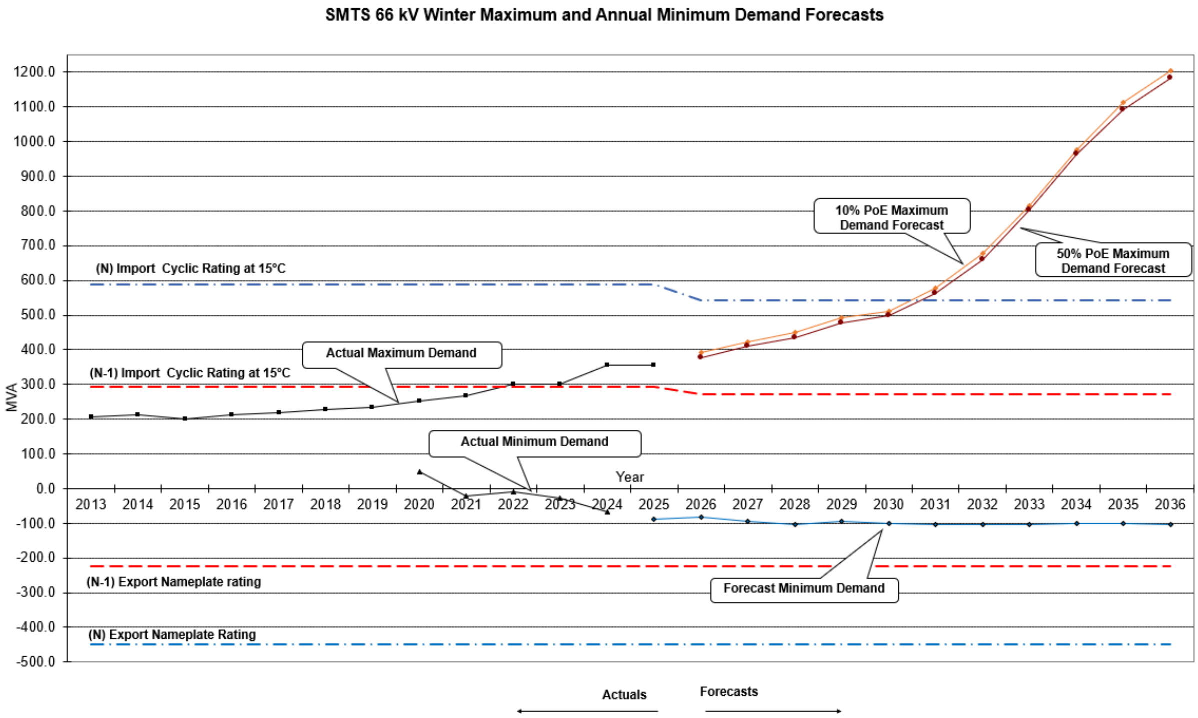
Site name	Status	Technology Type	Nameplate capacity (MW)
Somerton Power Station	Existing Plant	Gas	150
Cherry Tree Wind Farm	Existing Plant	Wind	57.5
Wollert Power Station	Existing Plant	Landfill Gas	7.7
Rubicon Power Station	Existing Plant	Hydro	14.6

Magnitude, probability and impact of constraints

The graph below depicts the 10th and 50th percentile maximum and minimum demand for summer forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export rating at 40°C ambient temperatures.



The graph below presents the 10th and 50th percentile maximum and minimum demand for winter forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export rating at 15°C ambient temperatures.



AusNet has included only committed block loads in its demand forecasts for SMTS, so non-committed loads are excluded. In contrast, Jemena's forecasts include non-committed block loads, which have been developed by applying diversity factors, ramping profiles, and load realisation factors, which are further adjusted based on connection likelihood informed by the latest progress of individual customers through the connection process.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figures shown above therefore provide an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

The station load has a power factor of 0.98 at maximum demand. Demand is expected to exceed 95% of the 50th percentile peak demand for 9.5 hours per annum.

In relation to minimum demand, it is estimated that:

- For 51.5 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of 0.98 at the time of minimum demand.

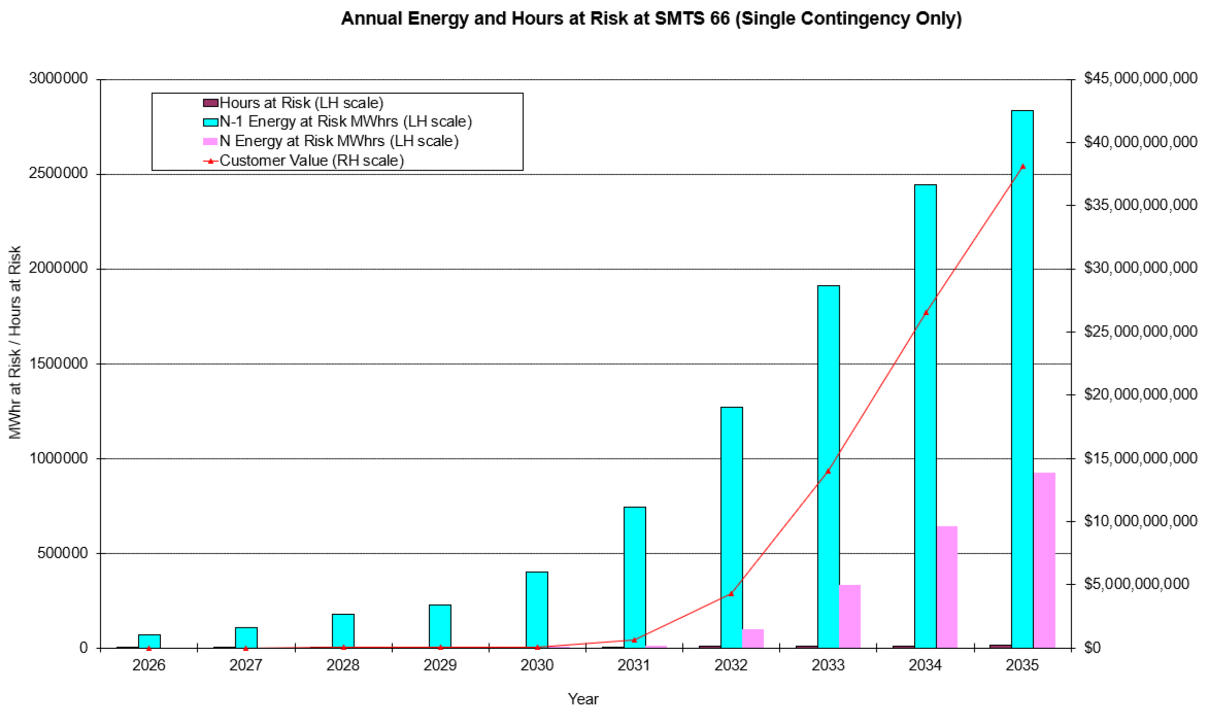
The “N” import ratings on the above charts indicate the maximum demand that can be supplied from SMTS with both transformers in service.

With the projected growth in customer demand in the area, it is expected that maximum demand at SMTS will exceed “N-1” import ratings in summer at the 10th and 50th percentile forecast peak demands for the whole of the ten-year forecast period, as shown in the graph above. The 10th and 50th percentile forecast peak demands will exceed the “N” import rating in summer from 2029.

In the winter, the rating of these transformers is higher than the summer rating due to lower ambient temperatures. Thus, energy at risk during the winter period is generally lower than during the summer period. The graph above shows the 10th and the 50th percentile winter maximum demand forecast together with the station’s operational “N” import rating and “N-1” import rating. SMTS exceeded its winter “N-1” import rating last year and is expected to exceed its “N” import rating under both 10th and 50th percentile winter maximum demand forecasts from winter 2030.

Minimum demand levels have remained well within the station’s operational “N” and “N-1” export ratings. This trend is expected to continue under both 50th percentile and 10th percentile minimum demand forecasts over the 10-year planning period. There is therefore not expected to be any need for augmentation to alleviate export constraints over the ten-year planning period.

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 maximum demand forecast, and the hours each year that the 50th percentile maximum demand forecast is expected to exceed the “N” and “N-1” station import capabilities. The line graph shows the value to customers of the expected unserved energy in each year, for the 50th percentile demand forecast.



As already noted, peak demand at SMTS 66 kV occurs in summer 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 information below therefore focuses on the energy at risk over the summer period.

Comments on Energy at Risk assuming Somerton Power Station is unavailable

Key statistics relating to energy at risk and expected unserved energy - assuming that the Somerton Power Station is unavailable - for the year of 2026/27 are summarised in the table below. The VCR at SMTS is $40,730 per MWh.

	MWh	Valued at VCR
N-1 Energy at risk, at 50th percentile maximum demand forecast	69,331	$2,824 million
Expected unserved energy at 50th percentile maximum demand	306	$12.5 million
N-1 Energy at risk, at 10th percentile demand maximum forecast	93,219	$3,797 million
Expected unserved energy at 10th percentile maximum demand	412	$16.8 million
70/30 weighted expected unserved energy value (see below)	**337**	**$13.8 million**

Under the probabilistic planning approach[105], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[106]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[107]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2026/27 is $13.8 million.

If one of the 220/66 kV transformers at SMTS is taken off line during peak loading times and the "N-1" station import rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA), which is operated by AusNet Transmission Group's TOC[108] to protect the connection assets from overloading[109], 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 139 MVA of load (i.e., the OSSCA Group 1 load), affecting approximately 44,600 customers. 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 assume that there is no embedded generation available to offset the 220/66 kV transformer loading. The Somerton Power Station (SPS) is

105 See section 3.1.

106 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

107 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

108 Transmission Operation Centre.

109 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.

capable of generating up to 150 MW 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 maximum demand at SMTS will coincide with periods of high wholesale electricity prices, resulting in a high likelihood that SPS will be generating. Even if SPS is generating to its full capacity there would be significant energy at risk at SMTS over the ten-year planning horizon for both 50th and 10th percentile summer maximum demand forecast.

Feasible options for alleviation of constraints

There are no transfers available out of the SMTS loop due to Rapid Earth Fault Current Limiter (REFCL) and line capacitive current limitations. Even during no Total Fire Ban days, the transfers available are insignificant.

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

1. Installation of a third 225 MVA 220/66 kV transformer at South Morang Terminal Station (SMTS). This may require the installation of fault limiting reactors to manage fault levels.

2. If the non-committed block loads identified in the demand forecast were to proceed, the existing infrastructure would be insufficient to accommodate the additional load. In such a scenario, the following options would provide the necessary capacity:

    a. Construct a new Donnybrook Terminal station (DBTS) and reconfigure the 66kV network between Thomastown Terminal Station (TTS), SMTS and DBTS.

    b. Construct a new Somerton Terminal station (SOTS) and reconfigure the 66kV network between TTS, SMTS and SOTS.

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.

4. Embedded Generation. As mentioned above, the Somerton power station is connected to SMTS. A network support agreement with SPS or other generators connected to the SMTS 66 kV bus will help to defer the need for network augmentation.

Preferred network option for alleviation of constraints

1. AusNet Services and Jemena commenced a Regulatory Investment Test for Transmission (RIT-T) by publishing a Project Specification Consultation Report (PSCR) in June 2025 to identify feasible solutions to address the energy at risk at SMTS. The next report of the RIT-T, the Project Assessment Draft Report (PADR) is expected to be published during the first quarter of 2026.

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:
    - 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; and

- 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;

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

The table on the following page provides more detailed data on the station rating, maximum and minimum demand forecasts, energy at risk and expected unserved energy assuming embedded generation is not available.

SOUTH MORANG TERMINAL STATION 66kV Loading (SMTS 66 kV)

Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station: AusNet Electricity Services (71%) Jemena Electricity Networks (29%)

Normal cyclic rating with all plant in service	519	MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating	259	MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating	271	MVA
Normal export rating with all plant in service	450	MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	273	MVA [See Note 7 below for interpretation of Export rating]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	431.4	460.2	481.1	510.2	557.3	644.7	753.3	896.5	1014.6	1105.7
50th percentile Winter Maximum Demand (MVA)	409.1	434.3	476.8	499.5	562.4	660.8	803.6	963.5	1092.3	1184.2
10th percentile Summer Maximum Demand (MVA)	459.3	486.5	507.4	534.4	584.2	670.5	779.6	931.6	1049.7	1139.8
10th percentile Winter Maximum Demand (MVA)	422.4	448.4	491.9	511.8	576.7	677.1	815.7	976.3	1112.4	1205.1
N - 1 energy at risk at 50th percentile demand (MWh)	69,331	107,203	176,197	227,597	398,652	742,924	1,269,677	1,910,815	2,442,649	2,836,126
N - 1 hours at risk at 50th percentile demand (hours)	1,709	1,912	2,451	3,372	4,321	6,010	6,987	7,518	7,849	8,042
N - 1 energy at risk at 10th percentile demand (MWh)	93,219	137,679	216,478	261,231	459,264	818,827	1,338,313	1,996,641	2,550,496	2,945,816
N - 1 hours at risk at 10th percentile demand (hours)	2,092	2,706	3,574	4,239	5,752	6,899	7,363	7,759	7,994	8,123
N energy at risk at 50th percentile demand (MWh)	0	0	0	0	117	11,549	100,064	335,791	641,450	924,271
N hours at risk at 50th percentile demand (hours)	0	0	0	0	5	35	473	1,720	3,401	4,991
N energy at risk at 10th percentile demand (MWh)	0	0	0	7	442	17,182	114,975	371,600	709,612	1,008,715
N hours at risk at 10th percentile demand (hours)	0	0	0	2	31	427	1,450	3,136	4,751	5,889
Expected Unserved Energy at 50th percentile demand (MWh)	306	473	778	1,005	1,878	14,830	105,672	344,230	652,238	936,797
Expected Unserved Energy at 10th percentile demand (MWh)	412	608	956	1,161	2,470	20,798	120,886	380,419	720,877	1,021,726
Expected Unserved Energy value at 50th percentile demand	$12.47M	$19.29M	$31.70M	$40.95M	$76.48M	$604.08M	$4304.29M	$14021.39M	$26567.34M	$38158.15M
Expected Unserved Energy value at 10th percentile demand	$16.77M	$24.77M	$38.94M	$47.28M	$100.62M	$847.16M	$4923.98M	$15495.43M	$29363.18M	$41617.53M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$13.76M	$20.93M	$33.87M	$42.85M	$83.72M	$677.00M	$4490.20M	$14463.60M	$27406.09M	$39195.96M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum demand (MVA)	-83.2	-93.7	-104.9	-95.8	-101.4	-104.2	-104.6	-103.3	-100.3	-100.3
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The summer and winter rating are at an ambient temperature of 40 degrees Centigrade and 15 degrees Centigrade, respectively.
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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the sector values given in section 3.2, 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^{th} and 10^{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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

SPRINGVALE TERMINAL STATION (SVTS)

Springvale Terminal Station (SVTS) is 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).

Embedded generation

A total of 186 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to SVTS. It consists of:

- 155.6 MW of rooftop solar PV, which includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW; and
- Four embedded generation sites with a total of 30.4 MW of large-scale embedded generation capacity (units over 1 MW).

Magnitude, probability, and impact of constraints

SVTS has four 150 MVA 220/66 kV transformers and operates in a split bus arrangement. Under system normal conditions the No.1 and No.2 transformers (B1 and B2) are operated in parallel as one group (SVTS 12) and supply the No.1 and No.2 buses. The No.3 and No.4 transformers (B3 and B4) are operated in parallel as a separate group (SVTS 34) and supply the No.3 and No.4 buses. Connection between No.1 and No.4 buses is maintained via transfer bus No.5. The 66 kV 2-3 and 4-5 bus-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 2-3 or 4-5 bus-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 SVTS 12 group should be kept within the import capabilities of the two transformers, B1 and B2, at all times.
- Load demand on the SVTS 34 group should be kept within the import capabilities of the two transformers, B3 and B4, at all times.
- Load demand on the total station should be kept within the import capabilities of any three transformers when one transformer is out of service.

The N import rating indicates the maximum demand that can be meet 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 export ratings on the chart reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

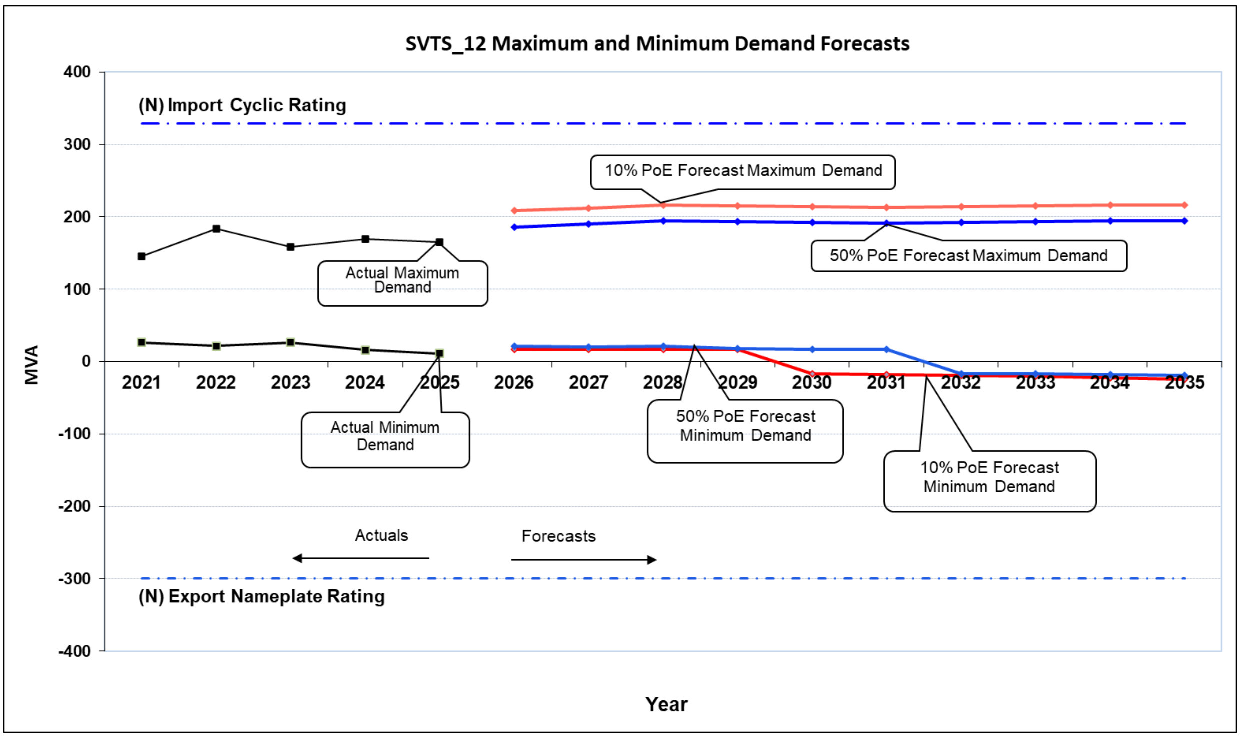
The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station or the bus group.

Transformer group SVTS 12: Summer Maximum Demand Forecasts

This bus group supplies Noble Park, Springvale South, Clarinda, Oakleigh East, Springvale, and Springvale West zone substations owned by United Energy.

The maximum demand in summer 2025 for the SVTS 12 bus group was 161.0 MW (164.7 MVA).

The graph below shows the historical demand, the 10th and 50th percentile maximum and minimum demand forecasts for SVTS 12 and the corresponding import and export ratings at 40°C ambient temperature with both transformers in service.



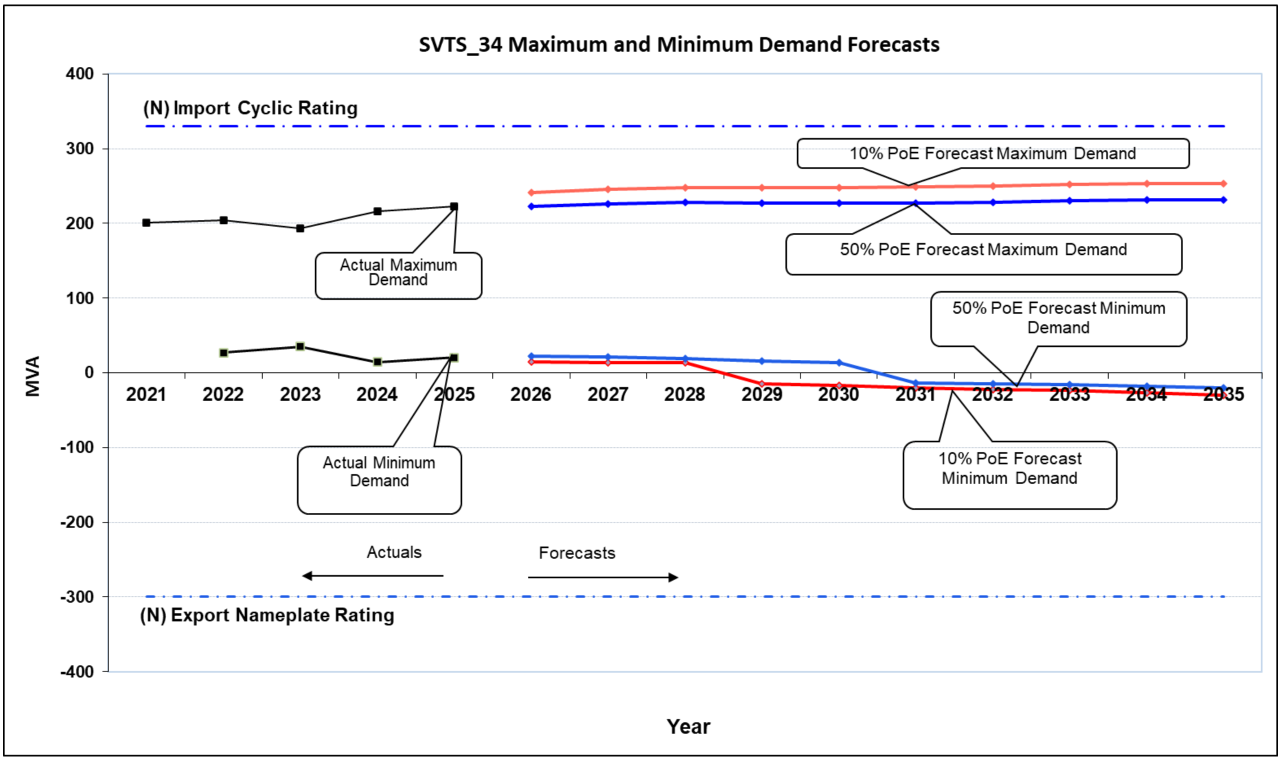
The graph above shows that with both transformers in service there is adequate import/export capacity to meet the anticipated maximum/minimum demand for the entire planning period.

Transformer group SVTS 34: Summer Maximum Demand 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. No embedded generation sites over 1 MW are connected at SVTS 3466 (B34) bus group.

The maximum demand in summer 2025 for the SVTS 3466 group was 221.5 MW (222.4 MVA).

The graph below depicts the historical demand, the 10th and 50th percentile maximum and minimum demand forecasts for SVTS34 and the corresponding import and export ratings at 40°C ambient temperature with both transformers in service.

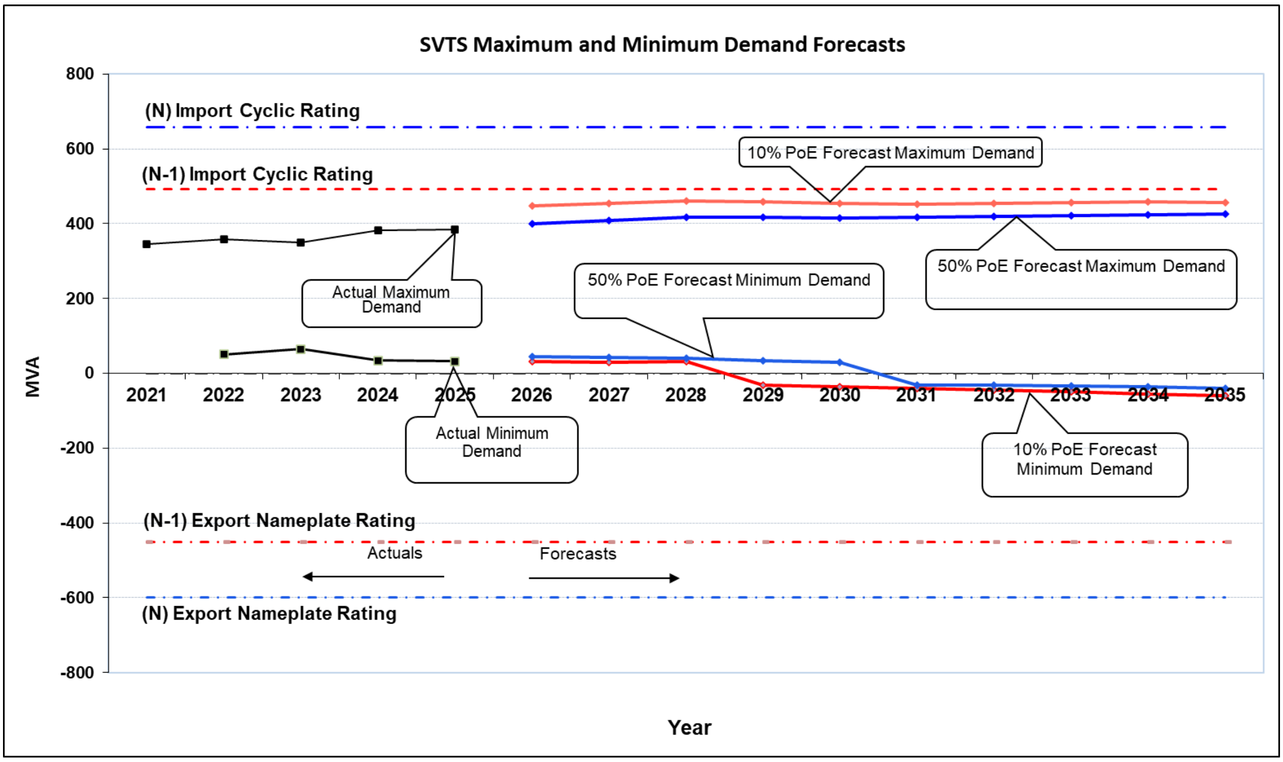


The graph above shows that with both transformers in service; there is adequate import/export capacity to meet the anticipated maximum/minimum demand for the entire planning period.

SVTS Total Demand Forecasts

SVTS 66 kV is a summer peaking terminal station. The maximum demand in summer 2025 was 380.9 MW (384.8 MVA).

The graph below depicts the historical demand, the 10th and 50th percentile total maximum and minimum demand forecasts together with the station's expected operational N import and export ratings (all transformers in service) and the (N-1) import and export ratings at 40°C ambient temperature.



There is approximately 58 MVA of load transfer available at SVTS 66 kV via the distribution network for summer 2025/26.

The graph also indicates that the maximum demand at SVTS 66 kV remains below its N-1 import rating over the ten-year planning period at 40°C ambient temperature. No limitations are noted for the minimum demand conditions over the ten-year planning period. Hence, no augmentation is planned at SVTS to alleviate import or export constraints in the forward planning period.

As already noted, there is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

It is estimated that:

- For 6 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.99.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

TEMPLESTOWE TERMINAL STATION (TSTS)

TSTS consists of three 150 MVA 220/66 kV transformers, and it is the main source of supply for over 130,500 customers in 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 Distribution, and Jemena Electricity Networks.

Embedded generation

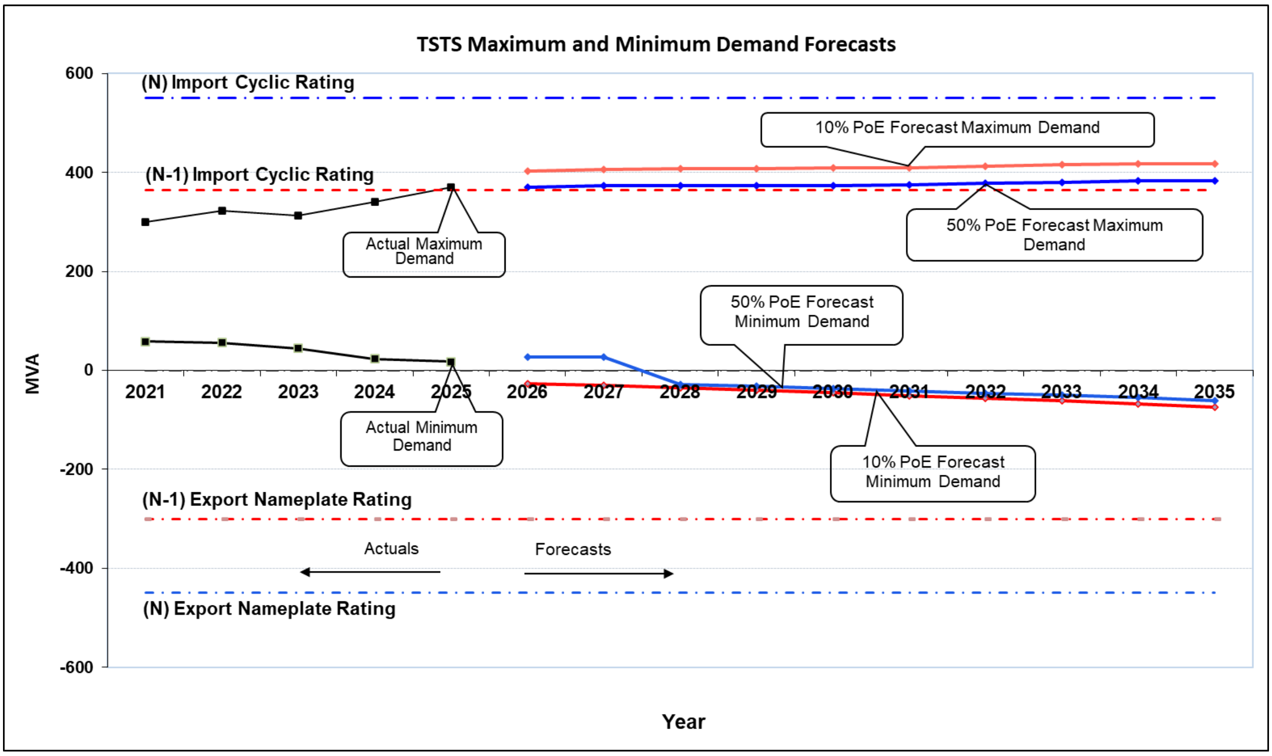
A total of 127 MW of embedded generation capacity is installed on the distribution system connected to TSTS, including:

- About 125.5 MW of rooftop solar PV is installed within the distribution system connected to TSTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.
- 1.5 MW of large-scale embedded generation.

Magnitude, probability, and impact of constraints

TSTS 66 kV is a summer critical terminal station. The station reached a maximum demand of 360.5 MW (371.0 MVA) in summer 2025.

The graph below depicts the historical demand, the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational N import and export ratings (all transformers in service) and the (N-1) import and export ratings at 40°C ambient temperature.

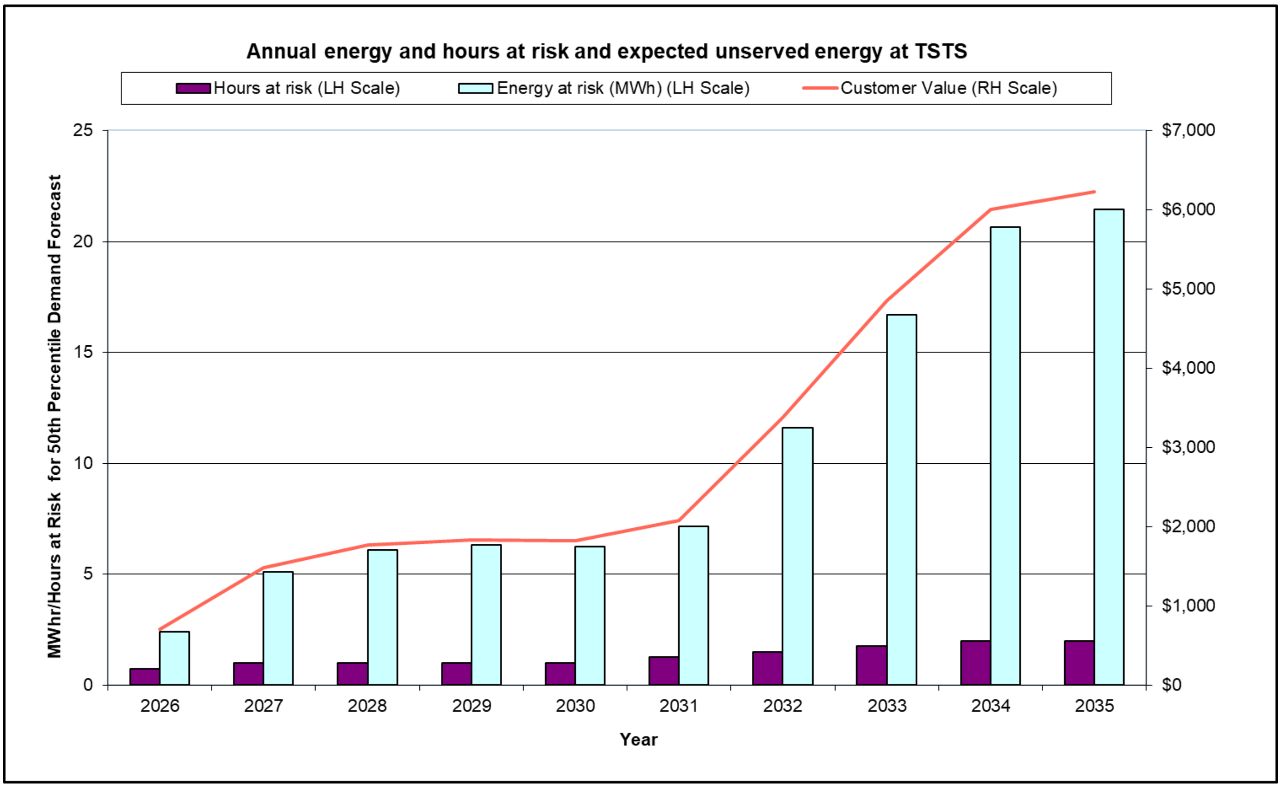


Forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

The export ratings on the chart reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

The N import rating on the chart indicates the maximum demand 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 maximum demand at TSTS remains below its N import rating within the 10-year planning period. The 10th and 50th percentile maximum demands are however forecast to exceed the station's (N-1) import rating from 2026.



Key statistics relating to energy at risk and expected unserved energy at TSTS for 2035 under N-1 outage conditions are summarised in the table below. The VCR for TSTS is $43,846 per MWh.

	MWh	Valued at VCR ($million)
Energy at risk, at 50th percentile demand forecast	21	$0.3
Expected unserved energy at 50th percentile demand	0.1	$0
Energy at risk, at 10th percentile demand forecast	177	$4.5
Expected unserved energy at 10th percentile demand	1.2	$0.03
70/30 weighted expected unserved energy value (see below)	**0.5**	**$0.02**

AusNet Transmission Group has evaluated the economic feasibility of replacing the B2 and B3 transformers at TSTS and concluded through a RIT-T that the preferred option is to replace the two transformers to address the asset failure risk. The TSTS B2 and B4 transformers have now been replaced with 150 MVA transformers with no material change to the station ratings.

Under the probabilistic planning approach[110], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[111]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[112]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2035 is $0.02 million.

It is noted that these estimates do not attribute any value to the prospective loss of generation that may be constrained. Where export constraints are material, they will be valued using a RIT-T analysis to evaluate options for addressing constraints.

If one of the 220/66 kV transformers at TSTS is taken offline during times of maximum demand and the (N-1) station import rating is exceeded, the OSSCA[113] load shedding scheme which is operated by AusNet Transmission Group's TOC[114] 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 import 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.

It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.74.

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 import constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy, CitiPower, AusNet and Jemena Electricity Networks have established and implemented the necessary plans that enable load transfers under contingency conditions. These plans are

110 See section 3.1.

111 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

112 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

113 Overload Shedding Scheme of Connection Asset.

114 Transmission Operations Centre.

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 51 MVA for summer 2025-26.

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 $45 million. The estimated total annual cost of this network augmentation is approximately $3.5 million.

On the present maximum demand forecasts, the fourth 220/66 kV transformer is unlikely 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; and
    - periodically review the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place.

2. Install a fourth 150 MVA 220/66 kV transformer 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 to alleviate import constraints, 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.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

The table on the following pages provides more detailed data on the station rating, demand forecasts, and import and export constraints.

TEMPLESTOWE TERMINAL STATION 66 kV

Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station: United Energy (42%), CitiPower (30%), Ausnet (20%), Jemena (8%)
Station operational rating (N elements in service): 550 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Import Rating: 365 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 409 MVA
Summer N-1 Station Export Rating: 300 MVA [See Note 7]
Winter N-1 Station Export Rating: 300 MVA [See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	369.7	372.7	373.7	373.9	373.8	374.5	377.7	380.8	383.0	383.4
50th percentile Winter Maximum Demand (MVA)	285.9	295.4	305.2	315.4	326.4	338.7	351.2	361.2	370.5	379.1
10th percentile Summer Maximum Demand (MVA)	402.4	406.3	407.8	408.5	408.6	409.2	413.1	416.3	417.8	418.0
10th percentile Winter Maximum Demand (MVA)	302.7	312.4	322.2	332.6	344.2	356.3	369.2	380.0	389.6	399.0
N-1 energy at risk at 50% percentile demand (MWh)	2.4	5.1	6.1	6.3	6.3	7.1	11.6	16.7	20.6	21.4
N-1 hours at risk at 50th percentile demand (hours)	0.8	1.0	1.0	1.0	1.0	1.3	1.5	1.8	2.0	2.0
N-1 energy at risk at 10% percentile demand (MWh)	74.1	93.8	102.6	107.2	108.0	111.8	138.0	162.8	174.8	176.5
N-1 hours at risk at 10th percentile demand (hours)	3.8	5.0	6.0	6.0	6.0	6.5	7.0	8.0	8.5	8.5
Expected Unserved Energy at 50th percentile demand (MWh)	0.02	0.03	0.04	0.04	0.04	0.05	0.08	0.11	0.14	0.14
Expected Unserved Energy at 10th percentile demand (MWh)	0.49	0.62	0.68	0.71	0.72	0.74	0.91	1.08	1.16	1.17
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M
Expected Unserved Energy value at 10th percentile demand	$0.02M	$0.03M	$0.03M	$0.03M	$0.03M	$0.03M	$0.04M	$0.05M	$0.05M	$0.05M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.02M	$0.02M	$0.02M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	27.1	30.0	34.8	39.1	44.5	51.4	56.8	61.2	66.9	74.3
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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^{th} and 10^{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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.
8. Negative MVA indicates exporting active power, irrespective of the direction of the reactive power flow.
9. Negative power factor indicates exporting reactive power (capacitive), irrespective of the direction of the active power flow.

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 64,681 customers in Terang and the surrounding area. The terminal station supply area includes Terang, Colac, Camperdown, Cobden, Warrnambool, Koroit, Portland and Hamilton.

Embedded generation

A total of 489.1 MW of embedded generation capacity is installed or proposed to be installed on the Powercor sub-transmission and distribution systems connected to TGTS. It consists of:

- 418.1 MW of large-scale embedded generation; and
- Around 71 MW of rooftop solar PV, including all the small-scale commercial and residential rooftop PV systems that are smaller than 1 MW.

The following table lists the registered embedded generators (>5 MW) that are installed or proposed to be installed on the Powercor network connected to TGTS.

Site name	Status	Technology Type	Nameplate capacity (MW)
Codrington Wind Farm	Existing Plant	Wind turbine	18.2
Yambuk	Existing Plant	Wind turbine	30
Oaklands Hill Wind Farm	Existing Plant	Wind turbine	67.2
Mortons Lane Wind Farm	Existing Plant	Wind turbine	19.5
Timboon West Wind Farm	Existing Plant	Wind turbine	7.2
Ferguson Wind Farm	Existing Plant	Wind turbine	12
Salt Creek Wind Farm	Existing Plant	Wind turbine	54
Mt Gellibrand Wind Farm[115]	Existing Plant	Wind turbine	138
Woolsthorpe Wind Farm	Proposed	Wind turbine	72

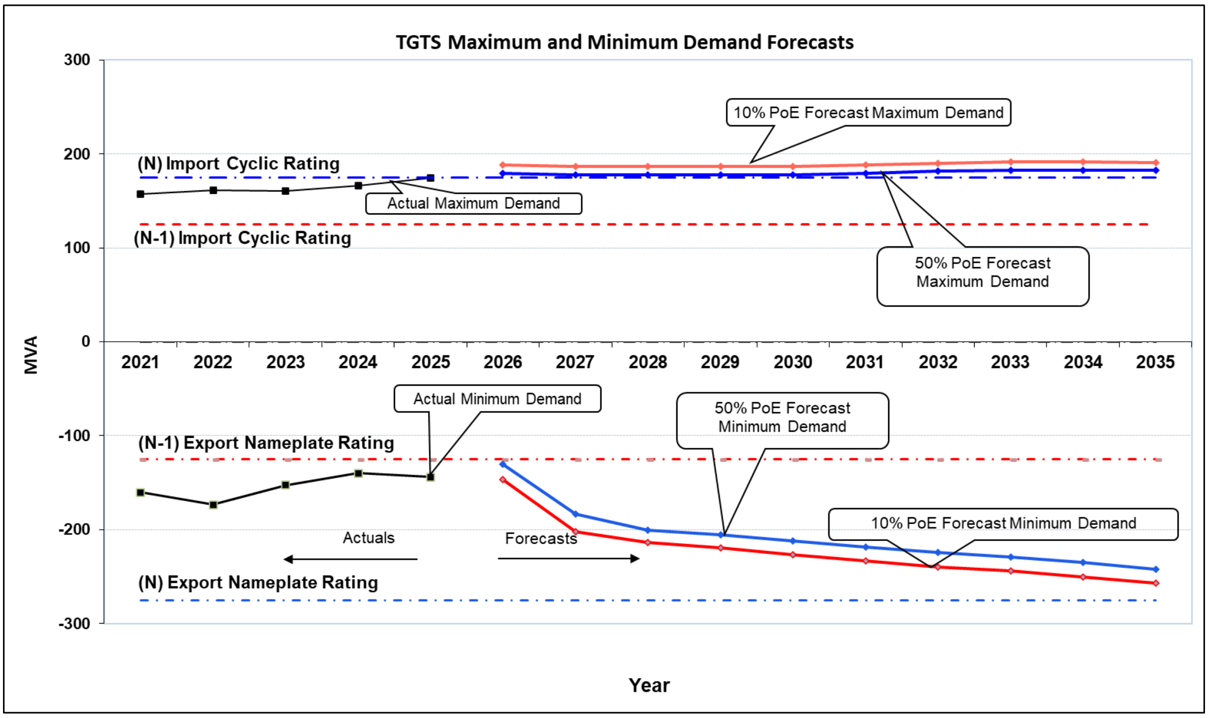
Magnitude, probability and impact of constraints

TGTS maximum demand for the past 5 years has been winter peaking but peaks can occur in summer or spring (depending upon the dairy industry load and the impact of wind farms connected to the 66 kV network).

The graph below shows:

[115] Mt Gellibrand Wind Farm is connected to a shared sub-transmission line between TGTS and GTS.

- the 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings, with import ratings determined at 40°C ambient temperature;
- actual station maximum demand reached 173.7 MW (174.6 MVA) in winter 2024; and
- actual minimum demand reached -123.7 MW (-144.0 MVA) in February 2025.



The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown above therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

It is estimated that:

- For 4 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of maximum demand is 0.98.

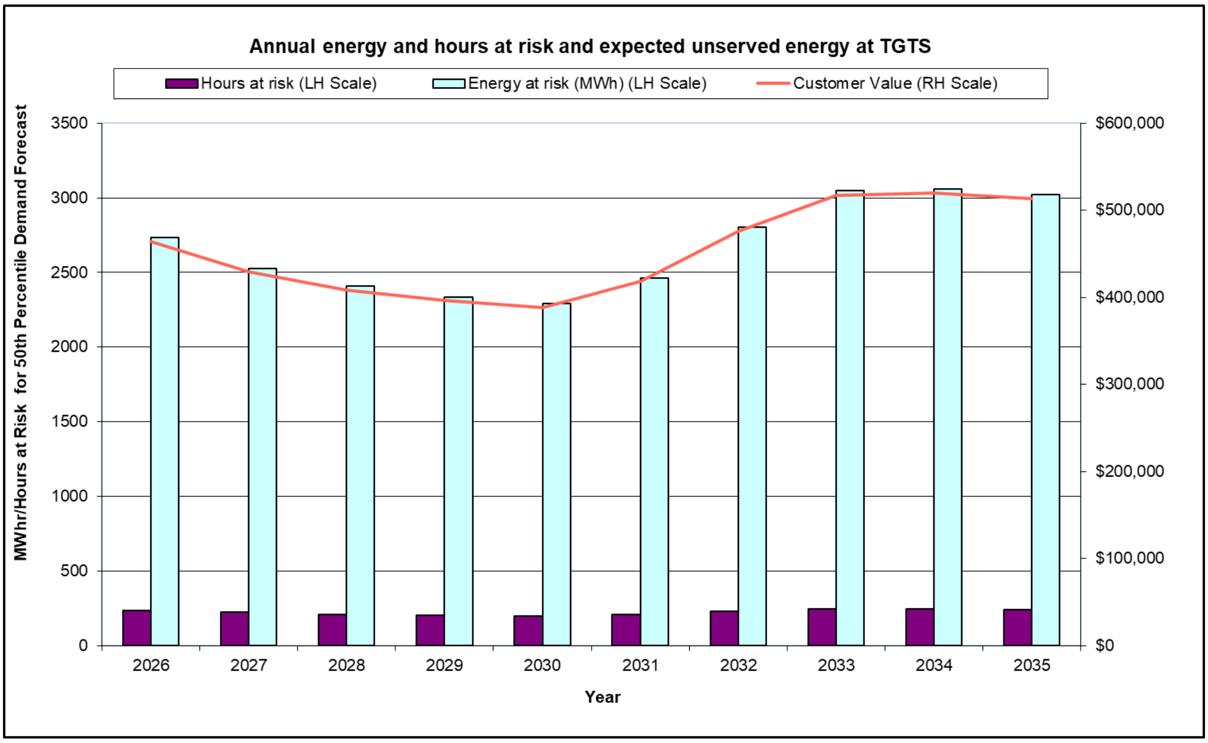
In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.86.

In the event of a transformer outage at TGTS the generators may need to reduce generation to avoid overloading the remaining transformer. A combination of runback schemes and AEMO constraint equations managing dispatch of scheduled and semi-scheduled generators is expected to manage power flows in accordance with the terminal station transformer export ratings.

Currently there is no planned augmentation at TGTS for generation connections. Additional generation, however, may require augmentation of transformer capacity, the cost of which would either be met by the connecting generator(s), or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile maximum demand forecast, and the hours per year that the 50th percentile maximum demand forecast is expected to exceed the N-1 import rating. The line graph shows the value to consumers of the expected unserved energy in each year for the 50th percentile maximum demand forecast, valued at the VCR for this terminal station, which is $38,403 per MWh.



The graph above shows that energy at risk and expected unserved energy are forecast to remain more or less unchanged over the 10-year forecast period. Key statistics relating to energy at risk and expected unserved energy for 2035 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	3,023	$116 million
Expected unserved energy at 50th percentile maximum demand	13.36	$0.5 million
Energy at risk, at 10th percentile maximum demand forecast	5,570	$214 million
Expected unserved energy at 10th percentile maximum demand	24.62	$1 million
70/30 weighted expected unserved energy value (see below)	**16.7**	**$0.6 million**

Under the probabilistic planning approach[116], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[117]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[118]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $0.6 million.

The table headed "Export" below shows that an increasing volume of output from embedded generators connected downstream of TGTS is forecast to be at risk of being curtailed over the planning period. By the end of the period in 2035, 132 MVA of embedded generation is at risk of curtailment for the loss of one transformer at TGTS. This equates to 865 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 4 MWh, which is immaterial from a transmission connection planning perspective.

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 network import constraint:

1. Replacing the #2 125 MVA 220/66 kV transformer at TGTS with a 150 MVA unit. For an indicative installation cost of $30 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.

2. Installation of a third 220/66 kV transformer (150 MVA) at TGTS at an indicative capital cost of $35 million (equating to a total annual cost of approximately $2.7 million).

116 See section 3.1.

117 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

118 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))

3. 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.

4. Embedded generation: The existing embedded generators that generate into the 66 kV infrastructure ex-TGTS with a total capacity of 346 MW may help to supply the loads in the TGTS supply area, and may defer the need for any capacity augmentation within the forecast period. Therefore, the actual level of expected unserved energy over the forecast period is likely to be below the forecasts shown in this risk assessment.

5. 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.

6. 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 to alleviate import constraints, it is proposed to:

1. Install a third 220/66 kV transformer (150 MVA) at TGTS at an indicative capital cost of $35 million. This equates to a total annual cost of approximately $2.7 million per annum. Even if the output of Salt Creek Wind Farm makes no material contribution to reducing the forecast expected unserved energy, the third transformer is not expected to be economically justified in the current forward planning period.

2. As temporary measures:

    - Maintain contingency plans to transfer load quickly to the Geelong Terminal Station (GTS) using 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 28 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.

    - Maintain existing generation runback schemes that limit generation output to avoid exceeding the remaining transformer's export rating in the event of a transformer outage at times of minimum demand and reverse power flows.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

TGTS Terminal Station
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

	MVA	
Nameplate rating with all plant in service	275	via 2 transformers (summer)
Summer N-1 Station Import Rating:	125	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	125	
Summer N-1 Station Export Rating:	125	[See Note 7]
Winter N-1 Station Export Rating:	125	[See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	161.4	161.5	158.5	156.9	155.3	154.4	155.1	155.7	155.6	154.6
50th percentile Winter Maximum Demand (MVA)	179.2	177.7	177.9	177.9	177.9	179.4	181.5	182.9	183.0	183.0
10th percentile Summer Maximum Demand (MVA)	183.6	179.5	176.5	174.6	172.6	171.6	172.0	172.3	172.0	170.9
10th percentile Winter Maximum Demand (MVA)	188.7	186.7	186.8	186.8	186.6	188.0	190.1	191.5	191.6	191.2
N-1 energy at risk at 50% percentile demand (MWh)	2733.9	2528.0	2406.6	2334.6	2289.6	2462.6	2802.4	3046.4	3060.3	3023.2
N-1 hours at risk at 50th percentile demand (hours)	236.5	223.8	209.5	204.5	199.5	209.5	231.0	245.0	245.5	241.3
N-1 energy at risk at 10% percentile demand (MWh)	6684.2	5658.0	5257.6	5041.9	4800.4	4958.0	5439.0	5770.0	5769.7	5570.4
N-1 hours at risk at 10th percentile demand (hours)	478.5	423.8	397.8	381.3	365.0	369.3	395.8	411.8	411.3	401.0
Expected Unserved Energy at 50th percentile demand (MWh)	12.08	11.17	10.64	10.32	10.12	10.88	12.39	13.47	13.53	13.36
Expected Unserved Energy at 10th percentile demand (MWh)	36.90	27.25	23.96	22.29	21.22	21.91	24.04	25.50	25.50	24.62
Expected Unserved Energy value at 50th percentile demand	$0.46M	$0.43M	$0.41M	$0.40M	$0.39M	$0.42M	$0.48M	$0.52M	$0.52M	$0.51M
Expected Unserved Energy value at 10th percentile demand	$1.42M	$1.05M	$0.92M	$0.86M	$0.81M	$0.84M	$0.92M	$0.98M	$0.98M	$0.95M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.75M	$0.61M	$0.56M	$0.53M	$0.52M	$0.55M	$0.61M	$0.66M	$0.66M	$0.64M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	146.8	202.3	213.9	219.7	226.6	233.6	239.4	244.0	250.0	256.9
Maximum generation at risk under N-1 (MVA)	21.8	77.3	88.9	94.7	101.6	108.6	114.4	119.0	125.0	131.9
N-1 energy curtailment (MWh)	31.4	1047.7	1254.9	1312.8	1270.2	1242.9	1204.8	1125.3	1052.7	864.7
Expected volume of export energy constrained (MWh)	0.1	4.6	5.5	5.8	5.6	5.5	5.3	5.0	4.7	3.8

Notes:
1. “N-1” means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 15 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

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 approximately 177,477 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.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figures shown below therefore provide an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.

The forecasts for each DB supplied from this station have been prepared using different approaches. Jemena has applied a forecasting methodology to include diversified non-committed block loads by applying ramping profiles, load realisation factors, and connections likelihood. The forecasts prepared by AusNet include only committed block loads, noting that there are significant block loads progressing through application processes. Non-network proponents should note that the use of non-committed block loads increases the uncertainty of the nature and timing of the augmentations.

Embedded Generation

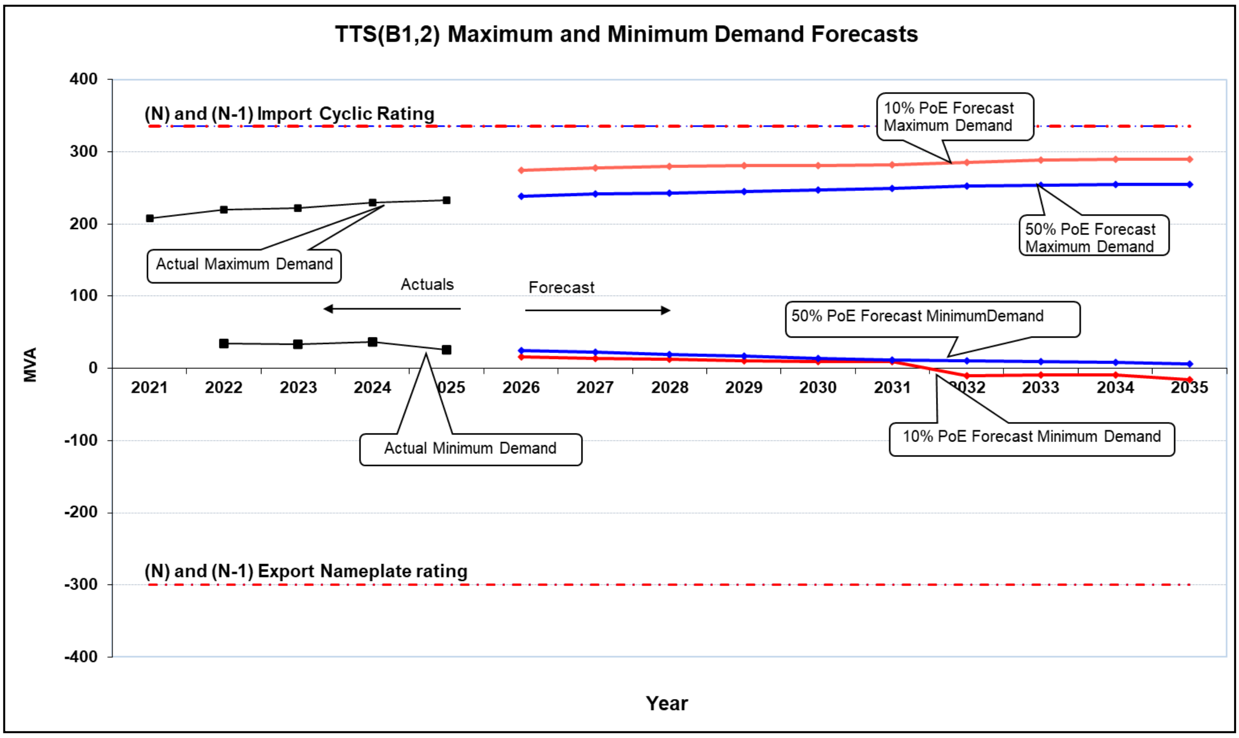
A total of 212.15 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to TTS 66 kV. It consists of:

- 197.27 MW of solar PV, which includes 43 MW in the AusNet distribution system and 154.27 MW in the Jemena distribution system. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW; and
- 14.88 MW capacity of embedded generation greater than 1 MW.

Transformer group TTS (B12) Demand Forecasts

The graph below shows:

- the 10th and 50th percentile maximum and minimum demand forecasts together with the station TTS (B12)'s operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings, with import ratings determined at 40°C ambient temperature;
- actual station TTS (B12) maximum demand reached 226.88 MW (233.01 MVA) in February 2025; and
- actual station TTS (B12) minimum demand reached 35.01 MW (35.35 MVA) in September 2024.



It is estimated that:

- For 7 hours per year, 95% of maximum demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of maximum demand is 0.97.

In relation to minimum demand, it is estimated that:

- For one hour per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

The graph shows that with all transformers in service, there is adequate import capacity to meet the anticipated maximum 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.

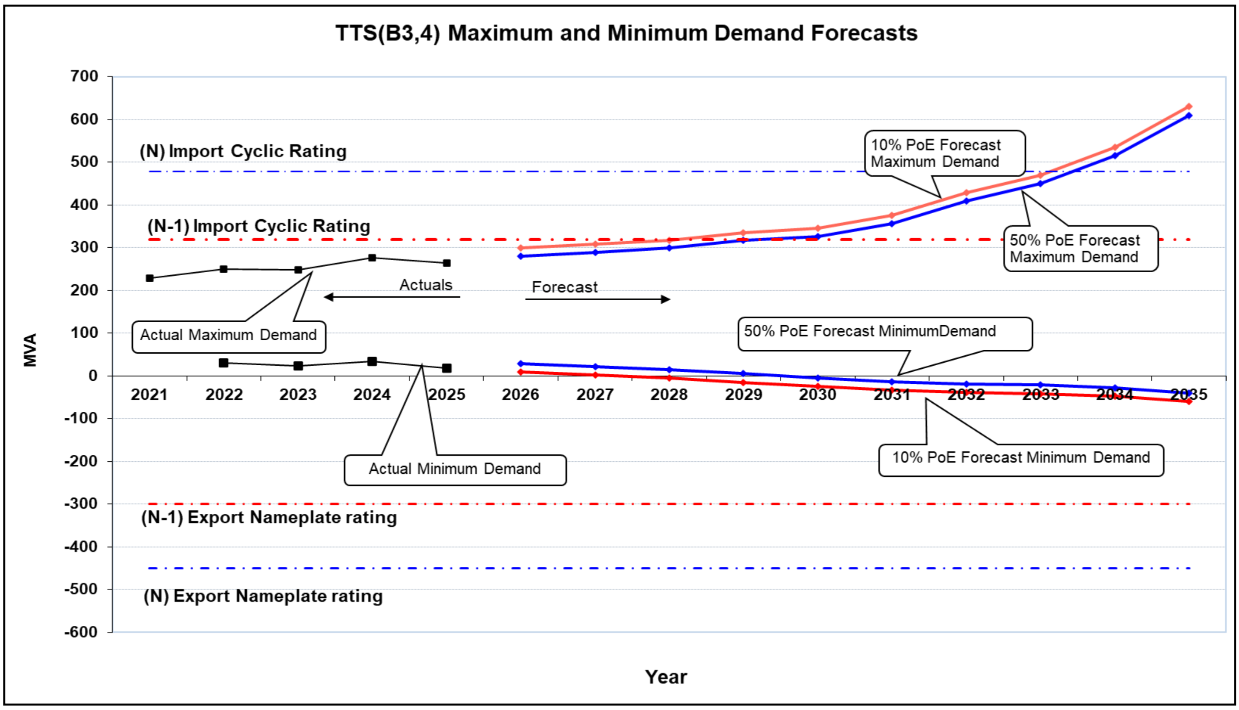
In effect then, the N-1 and N import ratings of the TTS(B12) group are equivalent. Thus there is sufficient import capacity provided by the TTS(B12) group to meet the anticipated maximum demand for the entire forecast period, even under a transformer outage condition.

The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the forecast period.

Transformer group TTS (B34) Demand Forecasts

The graph below shows:

- the 10th and 50th percentile maximum and minimum demand forecasts together with the station TTS (B34)'s operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings, with import ratings determined at 40°C ambient temperature;
- actual station TTS (B34) maximum demand reached 254.17 MW (263.21 MVA) in December 2024; and
- actual station TTS (B34) minimum demand reached 29.57 MW (30.20 MVA) in September 2024.



It is estimated that:

- For 18 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 0.97.

In relation to minimum demand, it is estimated that:

- For 3 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.98.

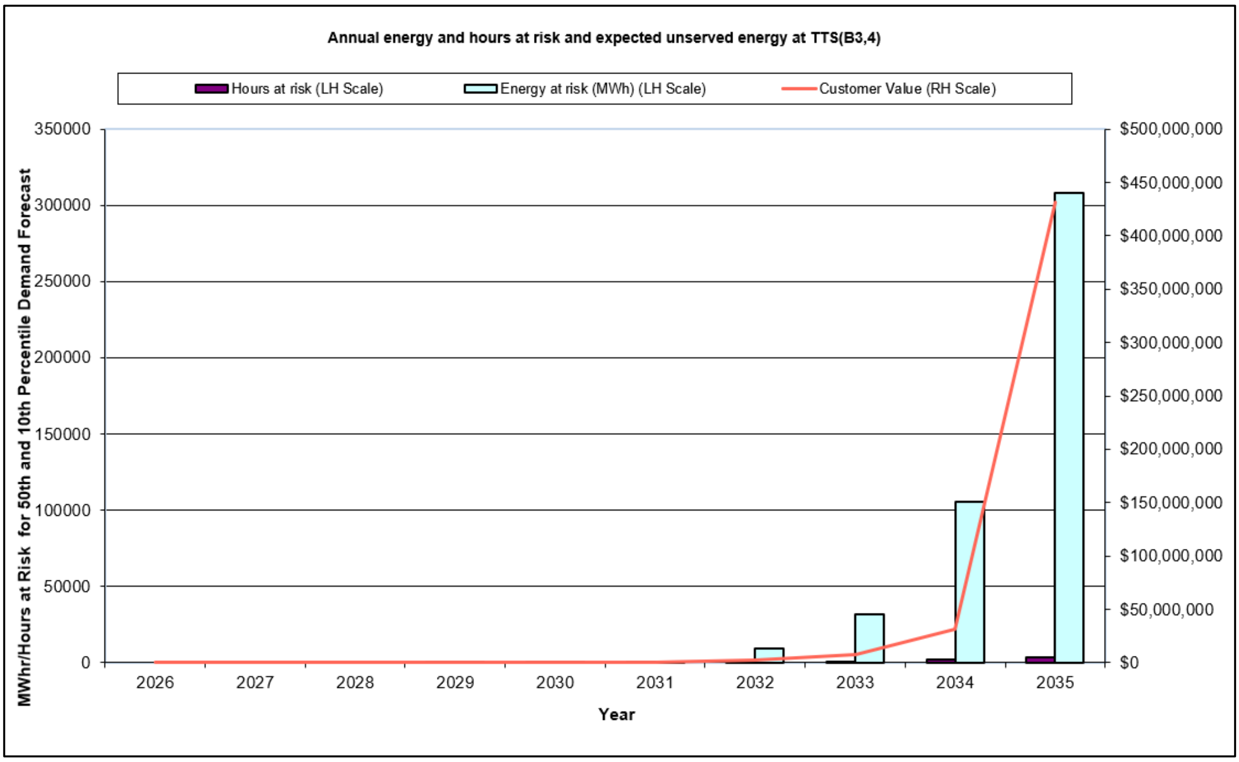
Due to new major load connections which are expected to have steady load uptake over the next ten-years TTS(B3,4) is expected to exhibit strong load growth.

The above graph shows from 2030, there is insufficient capacity to supply the forecast maximum demand at 50th percentile temperature at TTS(B3,4) if a forced outage of a transformer occurs, and from 2034 the forecast maximum demand at 50th percentile temperature at TTS(B3,4) is forecasted to exceed the station N import rating.

The graph also shows that there is expected to be sufficient station export capability to accommodate all embedded generation output over the forecast period.

Magnitude, probability and impact of energy risk at TTS(B3,4)

The bar chart below depicts the weighted average[119] energy at risk for the 50th and 10th percentile maximum demand forecast, and the hours per year that the weighted average of the 50th and 10th percentile maximum demand forecast is expected to exceed the N-1 and N import capability rating. The line graph shows the value to consumers of the weighted average expected unserved energy in each year. The VCR at TTS is $39,791.6 per MWh.



119 Weights of 0.7 and 0.3 are applied to the 50th and 10th percentile values, 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 Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

Key statistics relating to energy at risk and expected unserved energy for 2032 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	7,161	$285 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	46.6	$1.85 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	13,876	$552 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	90.2	$3.6 million
70/30 weighted expected unserved energy value (see below)	59.6	$2.37 million

Under the probabilistic planning approach[120], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.7) to determine the expected unserved energy cost in a year due to a major transformer outage[121].

The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[122]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2032 is $2.37 million and it increases to $431 million in 2034.

Possible Impact on Customers

System Normal Condition (Both transformers in service)

Applying the 10th percentile maximum demand forecast, there will be insufficient import capacity at TTS B(3,4) to meet maximum demand from year 2033 under system normal condition.

N-1 System Condition

If one of the TTS 220/66 kV transformers is taken off line during peak loading times, causing the TTS (B3,4) import rating to be exceeded, the OSSCA[123] load shedding scheme which is

120 See section 3.

121 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

122 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

123 Overload Shedding Scheme of Connection Asset.

operated by AusNet Transmission Group's TOC[124] will act swiftly to reduce the loads in blocks to within transformer import capabilities. Any load reductions that are in excess of the minimum amount required to limit load to the rated import 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 AusNet Services' 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 the emerging network import constraint:

1. Installation of two new transformers 220/66 kV transformer (150 MVA each) at TTS at an indicative capital cost of $35 million each (equating to a total annual cost of approximately $2.7 million per transformer).

2. Construct a new Donnybrook Terminal station (DBTS) and reconfigure the 66 kV network between TTS, SMTS and DBTS.

3. Construct a new Somerton Terminal station (SOTS) and reconfigure the 66 kV network between TTS, SMTS and SOTS.

4. 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.

5. Embedded generation, connected to the TTS B(3,4), may substitute capacity augmentations.

6. Possible uptake of battery storage in the future could provide some contribution to supporting the peak load.

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 TTS B(3,4) to alleviate import constraints, it is proposed to install two new 220/66 kV transformers (150 MVA each) at TTS at an indicative capital cost of $35 million each. This equates to a total annual cost of approximately $5.4 million per annum. Based on the demand forecasts presented here, commissioning of this augmentation between 2032 and 2033 would be economically justified.

In addition to these works, if there is an increase in the ramping of new block loads, it is expected that the timing of further augmentation works may be brought forward, with additional transformation capacity delivered through the development of DBTS or SOTS.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

[124] Transmission Operations Centre.

Thomastown Terminal Station (B12 transformer group)

Detailed Import and Export Limitation data

Distribution Businesses supplied by this station: JEN (53%), Ausnet Services(47%)

Station operational rating (N elements in service): 335 MVA

Summer N-1 Station Import Rating: 335 MVA

N-1 Station Export Rating: 300 MVA

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	238.1	241.2	242.9	244.9	247.4	249.4	252.7	253.2	254.1	254.2
50th percentile Winter Maximum Demand (MVA)	181.7	188.1	193.4	197.6	202.2	204.9	209.3	211.6	212.7	213.6
10th percentile Summer Maximum Demand (MVA)	274.6	277.5	279.4	280.9	281.1	282.2	285.3	288.9	289.0	289.8
10th percentile Winter Maximum Demand (MVA)	185.8	191.8	197.1	201.1	205.3	208.6	212.9	215.5	216.7	216.9
N energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N hours at risk at 50% percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N hours at risk at 10% percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	24.7	22.1	19.6	16.7	14.1	11.6	10.2	9.6	8.3	6.0
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

Thomastown Terminal Station (B34 transformer group)

Detailed Import and Export Limitation data

Distribution Businesses supplied by this station: JEN (100%)

Station operational rating (N elements in service): 479 MVA

Summer N-1 Station Import Rating: 319 MVA

N-1 Station Export Rating: 300 MVA

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	279.9	288.5	299.2	316.9	326.7	356.8	409.4	449.7	515.3	610.0
50th percentile Winter Maximum Demand (MVA)	273.1	287.9	304.8	328.3	344.4	376.9	431.5	472.1	537.5	633.9
10th percentile Summer Maximum Demand (MVA)	299.8	307.8	317.7	335.5	345.1	375.3	428.6	469.4	535.1	629.7
10th percentile Winter Maximum Demand (MVA)	290.2	304.9	321.6	344.8	360.6	393.4	448.4	488.8	553.9	649.9
N energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	7439.3
N hours at risk at 50% percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8	239.0
N energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	165.4	12295.3
N hours at risk at 10% percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.5	345.0
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	4.9	151.7	7161.1	27482.5	97318.8	286789.9
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	1.0	12.8	313.0	786.5	1816.3	3492.8
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	22.0	48.8	753.1	13876.5	41233.2	124579.4	328340.6
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	2.5	3.3	52.8	495.0	1029.0	2167.0	3728.8
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.03	0.99	46.55	178.64	696.92	9303.47
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.14	0.32	4.90	90.20	268.02	975.19	14429.50
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.04M	$1.85M	$7.11M	$27.73M	$370.20M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M	$0.19M	$3.59M	$10.66M	$38.80M	$574.17M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.09M	$2.37M	$8.18M	$31.05M	$431.39M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	27.9	21.3	13.5	4.8	-5.1	-14.2	-19.4	-20.8	-28.1	-40.0
Maximum generation at risk under N-1 (MVA)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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)
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

TYABB TERMINAL STATION (TBTS)

TBTS consists of three 150 MVA 220/66 kV transformers and is the main source of supply for over 124,000 customers on the Mornington Peninsula. The geographic coverage of the area spans from Frankston South in the north to Portsea in the south.

Embedded generation

A total of 191 MW of embedded generation capacity is installed on the sub transmission and distribution systems connected to TBTS. It consists of:

- About 148 MW of rooftop solar PV, including all the residential and small-commercial rooftop PV systems that are smaller than 1 MW; and
- 43 MW of large-scale embedded generation.

There are an additional 9 generation units providing 9 MW of network support for the lower Mornington Peninsula sub-transmission constraints only during the summer period.

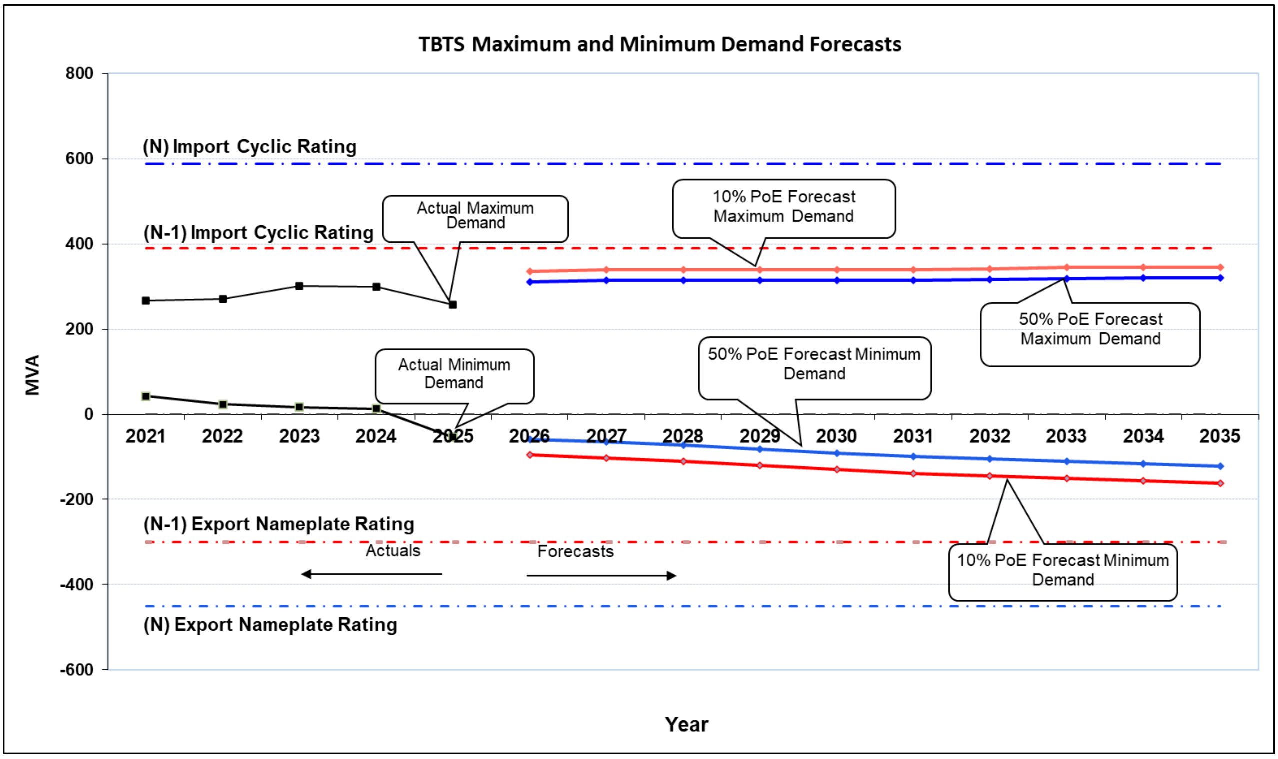
Magnitude, probability, and impact of constraints

TBTS 66 kV is a summer critical station. Maximum 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 that maximum demand at TBTS is directly related to air-conditioning use during the summer holiday period along the coastal belt of the Mornington Peninsula, the peak is very sensitive to the maximum ambient temperature at this time. The station maximum demand reached 252.6 MW (256.9 MVA) in summer 2025.

The graph below shows the historical demand, the 10^{th} and 50^{th} percentile maximum and minimum demand forecasts together with the station's operational N import and export ratings (all transformers in service) and the N-1 import and export ratings at 40°C ambient temperature.

The N import rating on the chart below indicates the maximum demand 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 export ratings on the chart reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

The graph above shows that with one transformer out of service, maximum demand at TBTS is expected to remain well within the (N-1) station rating over the next ten years. Therefore, the need for augmentation at TBTS to alleviate import constraints is not expected to arise over the next decade.

There is approximately 21 MVA of load transfer available at TBTS for summer 2025-26.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

It is estimated that:

- For 6 hours per year, 95% of maximum demand is expected to be reached.
- The station load power factor at the time of maximum demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 4 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.92.

WEMEN TERMINAL STATION (WETS)

Wemen Terminal Station (WETS) was commissioned in February 2012. Initially, WETS consisted of one 70 MVA 235/66 kV transformer supplying part of the 66 kV network previously supplied by RCTS. An additional 70 MVA transformer was installed in 2018, increasing the N rating to 140 MVA. This configuration is the main source of supply for approximately 4,134 customers in the Wemen, Boundary Bend and Ouyen areas.

Embedded generation

A total of 182.5 MW of embedded generation capacity is installed on the Powercor sub-transmission and distribution systems connected to WETS. It consists of:

- 175.8 MW of large-scale embedded generation; and
- 6.7 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the large-scale embedded generators (>5 MW) that are installed on the Powercor network connected to WETS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Bannerton Solar Park	Existing Plant	Solar PV	88
Wemen Solar Farm	Existing Plant	Solar PV	87.8

Magnitude, probability and impact of constraints

The following observations and risk assessment are based on actual readings of power flow at the Terminal Station Connection points. It therefore accounts for the present load and generation combination.

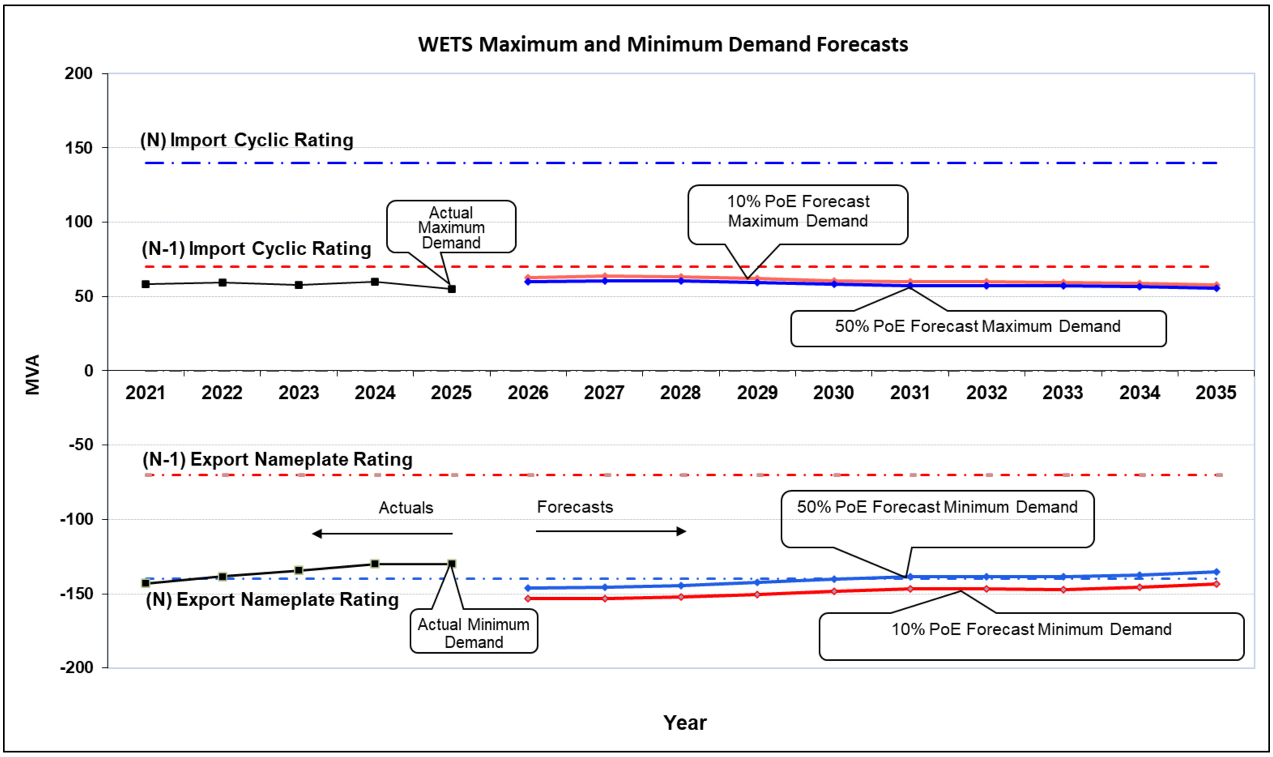
WETS maximum demand occurs in summer. The maximum demand on the station reached 52.9 MW (55.3 MVA) in summer 2025. Due to the input of generation connected to the station, reverse power flows occur during low load periods. The minimum demand at WETS reached -129.3 MW (-129.9 MVA) in November 2024.

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecast together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at 40°C ambient temperature.

To mitigate the risk of generation curtailment of new solar farms in the area an additional 70 MVA transformer was installed on the WETS 66 kV system in 2018. The transformer is running in parallel with the existing 70 MVA transformer. In advance of AusNet Transmission Services completing its review of ratings at WETS 66 kV, this risk assessment adopts the conservative assumption that from 2019 the station thermal rating of WETS 66 kV is reduced from cyclic to nameplate.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



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 maximum demand is 0.96.

In relation to minimum demand, it is estimated that:

- For 62 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99.

The graph shows there is sufficient capacity at the station to meet all expected maximum demand at the 50th and 10th percentile temperatures over the forecast period, even with one transformer out of service. The 50th and 10th percentile maximum demands are forecast to decrease slightly over the ten-year planning horizon.

The graph also shows that from 2026, at the 10th and 50th percentile minimum demands, there is insufficient capacity at the station to meet all expected minimum demand, even with all transformers in service. Minimum demand is forecast to increase over the planning period, so the volume of expected constrained-off generation is expected to decrease from 2026.

The above graph shows that in 2026, 83.5 MVA of embedded generation is at risk of curtailment for the loss of one transformer at WETS. This equates to 61,600 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 983 MWh, which is unlikely to economically justify transmission connection augmentation.

It is noted that in 2026, the 10th percentile minimum demand is 13.5 MVA lower than the (N) export rating. If actual minimum demand falls below the (N) export rating, or in the event of a transformer outage at WETS, the generators may have to reduce generation to avoid overloading the remaining transformer. AEMO has a constraint equation to manage the terminal station transformer reverse loading. The generators are sent dispatch signals to reduce generation if the constraint equation binds. Any generation reduction is implemented through AEMO’s dispatch process. In addition, Powercor has implemented transformer overload protection schemes at the large-scale generation sites as a backup to the AEMO constraint equation.

Accommodation of additional generation may necessitate augmentation of transformer capacity, the cost of which would either be met by the connecting generator(s) or would be recovered from load customers where a RIT-T demonstrates that the augmentation delivers net market benefits.

The table on the following page provides more detailed data on the station rating, demand forecasts, and import and export constraints.

Wemen Terminal Station
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

	MVA	
Nameplate rating with all plant in service	140	via 2 transformers (summer)
Summer N-1 Station Import Rating:	70	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	70	
Summer N-1 Station Export Rating:	70	[See Note 7]
Winter N-1 Station Export Rating:	70	[See Note 7]

Import	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
50th percentile Summer Maximum Demand (MVA)	60.1	60.7	60.3	59.4	58.2	57.4	57.3	57.2	56.6	55.4
50th percentile Winter Maximum Demand (MVA)	60.8	60.6	59.9	58.9	57.8	57.4	57.4	57.3	56.3	55.1
10th percentile Summer Maximum Demand (MVA)	62.9	63.6	63.0	61.9	60.7	60.1	59.8	59.6	59.0	57.8
10th percentile Winter Maximum Demand (MVA)	63.7	63.5	62.7	61.5	60.3	60.0	60.0	59.6	58.5	57.2
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	153.5	153.1	152.0	150.3	148.1	146.8	146.9	147.1	145.9	143.5
Maximum generation at risk under N-1 (MVA)	83.5	83.1	82.0	80.3	78.1	76.8	76.9	77.1	75.9	73.5
N-1 energy curtailment (MWh)	61611.4	60614.6	59152.9	56989.6	54461.7	53426.2	53659.4	53515.2	51758.9	48987.1
Expected volume of export energy constrained (MWh)	983.0	873.7	730.6	562.0	406.3	352.7	363.6	358.5	289.5	227.8

Notes:
1. “N-1” means station output capability rating with outage of one transformer. The summer 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 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 2.65 months. The outage probability is derived from the base reliability data given in Section 4.7.
5. The value of unserved energy is derived from the relevant climate zone and sector VCR values given in the AER VCR December 2024 final determination, 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^{th} and 10^{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
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.

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 a major customer in CitiPower's distribution network. The terminal station provides a major 22 kV supply to the West Melbourne area.

As part of its asset renewal program, AusNet Transmission Group plans to retire all of the existing WMTS 22 kV systems. Load transfers have been made from WMTS 22 to both BTS 66 and WMTS 66 over the last 5 years. The remaining VR North Melbourne substation is planned to move to the WMTS 66 system in the near future. These offloads are shown in the graph below.

The peak load on the station reached 6.4 MW in summer 2024. It is estimated that:

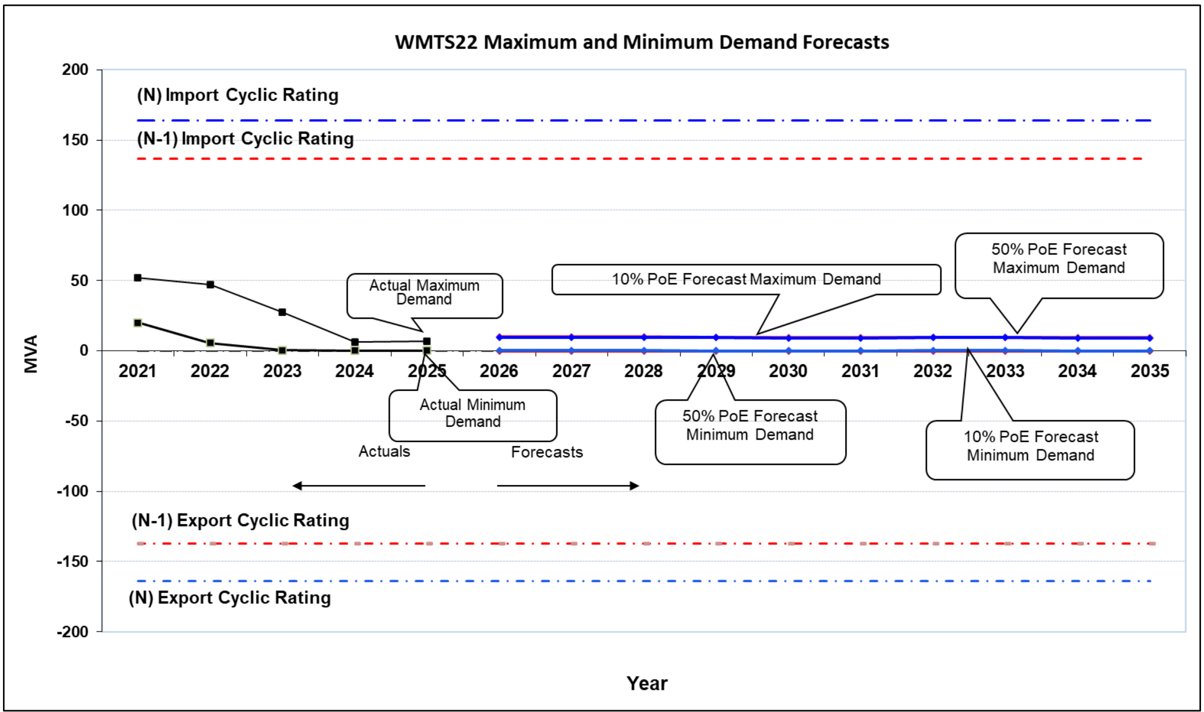
- For 4 hours per year, 95% of peak demand is expected to be reached under the 50th percentile summer demand forecast.
- The station load power factor at the time of peak demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 4 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand was 0.83.

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 40ºC 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. It is planned that all WMTS 22kV load will be offloaded to WMTS 66 kV and BTS 66 kV before 2026. As part of its asset renewal program, AusNet Transmission Group plans to retire all the existing WMTS 22 kV systems, but negotiations are currently underway to defer retirement to enable supply to be maintained to an existing major customer until the customer can be transferred to the 66 kV system.

There is expected to be sufficient station export capability to accommodate all embedded generation output until the station is de-commissioned.

WEST MELBOURNE TERMINAL STATION 66 kV (WMTS 66 kV)

WMTS 66 kV is a summer critical station consisting of three 225 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (79%) and Jemena Electricity Networks (21%). It provides major supply for 47,816 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.

As part of its asset renewal program, AusNet Transmission Group replaced all four 150 MVA 220/66 kV transformer units (B1, B2, B3 and B4) with three 225 MVA transformer units. The project was completed in 2021. This enables all three transformers to operate in parallel which therefore increased the station ratings while maintaining the fault levels within the terminal station fault level rating.

Embedded generation

About 18.3 MW of solar PV is installed on WMTS 66 which includes 2.3 MW in the CitiPower distribution system and 16 MW in the Jemena distribution system. This total includes all the residential and small-commercial rooftop solar PV systems (<1 MW).

Magnitude, probability and impact of constraints

The maximum demand on the station was 256.9 MW (265.3 MVA) in summer 2025 which was approximately the same as summer 2024.

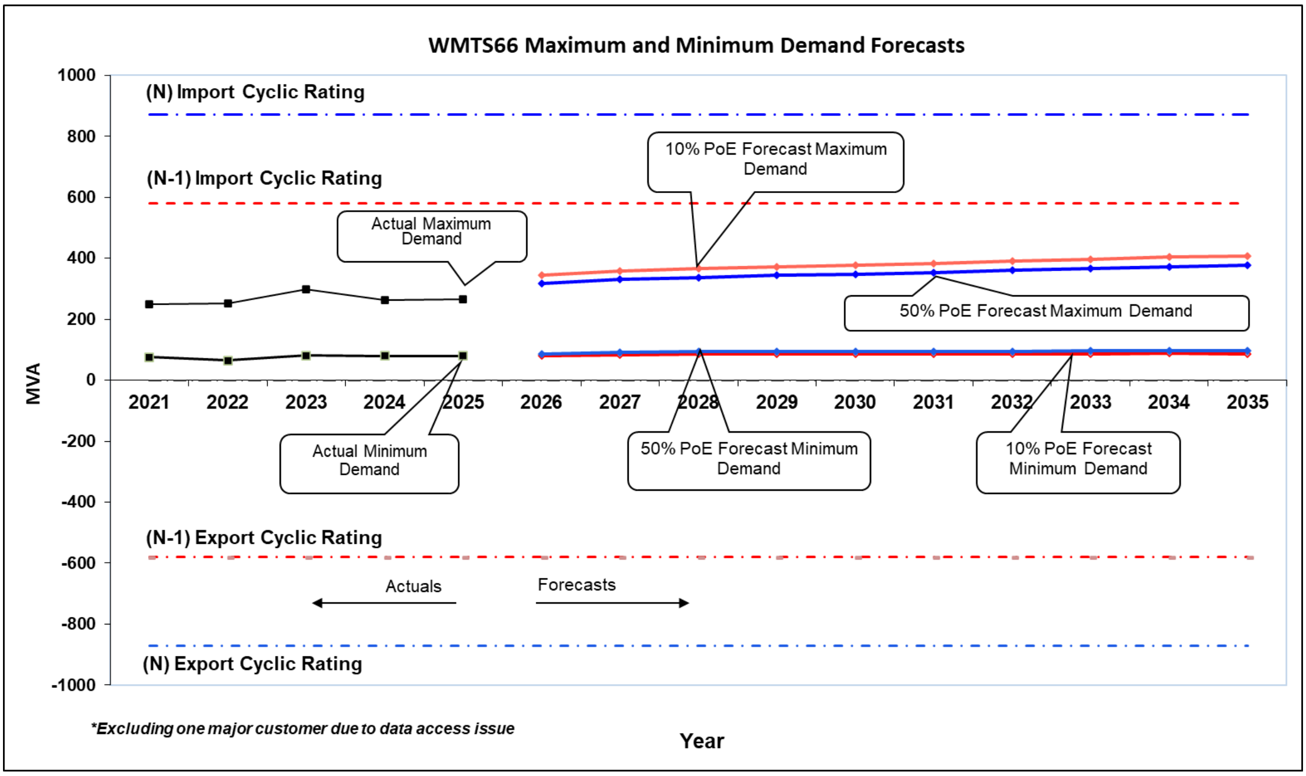
The graph below shows:

- the station's N and N-1 import cyclic ratings at 40ºC prior to the transformer replacement works and the new N and N-1 cyclic ratings with three new 225 MVA transformers commissioned in 2021; and
- the latest 10th and 50th percentile maximum and minimum demand forecasts over the next ten years.

The forecast maximum demand includes the load transfers from WMTS 22 to WMTS 66 prior to the planned decommissioning of the 22 kV supply from WMTS, and new 66 kV supplies for Melbourne Metro Tunnel which were connected in 2021 (8 MVA) and will gradually increase to 53 MVA by 2040. It is noted that at present, there is insufficient data available to enable the impact of Western Intake Substations to be considered in the forecast.

WMTS 66 is one of the terminal stations supplying the Melbourne CBD. To meet the Distribution Code of Practice requirements regarding security of supply to the Melbourne CBD, CitiPower has been undertaking works to re-configure the CBD 66 kV network to provide the required security to maintain supply from alternate supply points. This means that for a 'N-1' event in other parts of the CBD network, additional load can be switched onto WMTS 66. This required additional capacity must be reserved at the terminal station to ensure that CBD load can be supplied under any of the CBD security contingency arrangements.

It should be noted that the ratings shown below are thermal ratings only. For some stations, export ratings (to accommodate reverse power flow) will be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the station's thermal rating. Work is underway to quantify the impacts of system limitations on station export ratings. Until that work is finalised, thermal ratings are shown.



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.

In relation to minimum demand, it is estimated that:

- For 112 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.96.

The graph shows that currently there is sufficient import capacity at WMTS 66 kV to meet the forecast 10th percentile and 50th percentile maximum demand over the planning period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action to alleviate import constraints is not expected to arise over the next ten years.

There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

WODONGA TERMINAL STATION (WOTS 66 kV and 22 kV)

Wodonga Terminal Station (WOTS) 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. In addition, in 2023 a new 75 MVA spare transformer was placed on-site at WOTS to act as a cold spare.

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. In late 2025, AusNet Transmission Group reviewed and updated the cyclic ratings of the WOTS transformers. As a result, the "N" summer cyclic rating (40 °C) and winter cyclic rating (15 °C) were both reduced to 150 MVA, while the "N-1" cyclic ratings were both reduced to 75 MVA.

Embedded generation

A total of 128 MW of embedded generation capacity is installed on the AusNet sub-transmission and distribution systems connected to WOTS. It consists of:

- 65 MW of large-scale embedded generation; and
- 63 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

The following table lists the embedded generators (>5 MW) that are installed on the AusNet network connected to WOTS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Hume Power Station	Existing Plant	Hydro	58

Magnitude, probability and impact of constraints

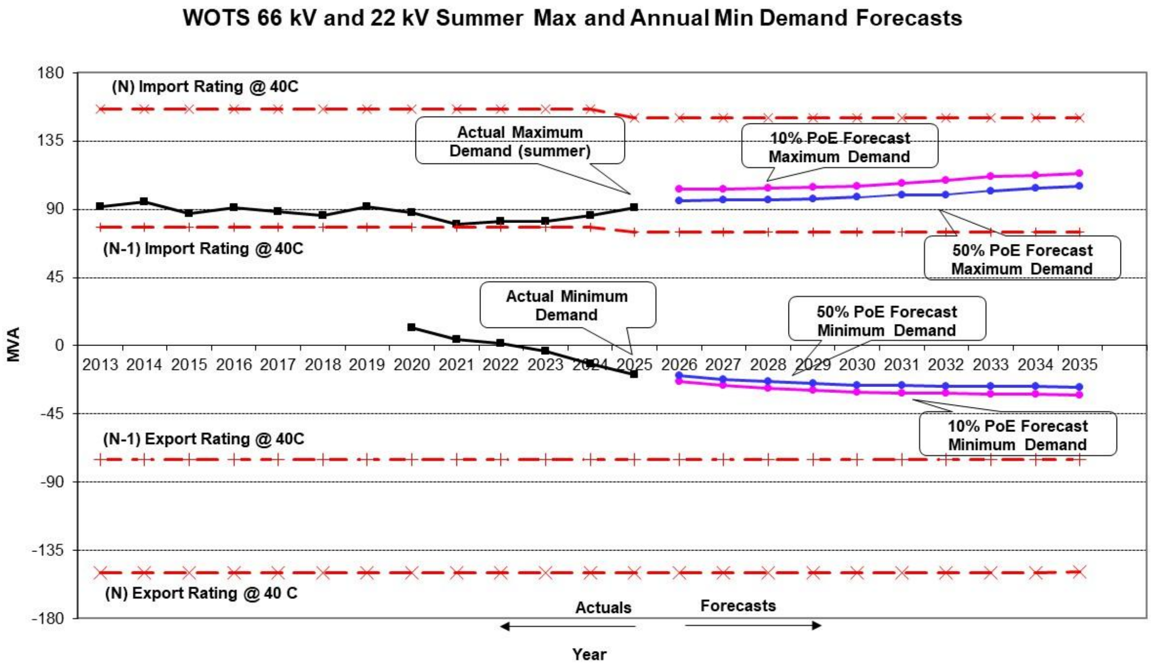
Maximum demand at WOTS occurs in summer, and the combined 66 kV and 22 kV summer maximum demand is forecast to gradually increase for the next ten years. To accurately assess the transformer loading, the 66 kV and 22 kV loads need to be considered together because of the physical arrangement of the transformer windings.

The maximum demand on the station reached 107.4 MVA in summer 2008/09 but had a period of decline before recently flattening. The recorded maximum demand in summer 2024/25 was 89.40 MW (91.20 MVA).

The graph below depicts the 10th and 50th percentile summer maximum and minimum demand forecasts together with the station's operational "N" import and export ratings (all transformers in service) and the "N-1" import and export ratings at an ambient temperature of 40°C.

The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The figure shown below therefore provides an initial indication of the headroom that may be available to accommodate additional export capacity at the terminal station.

For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed with the connecting party.



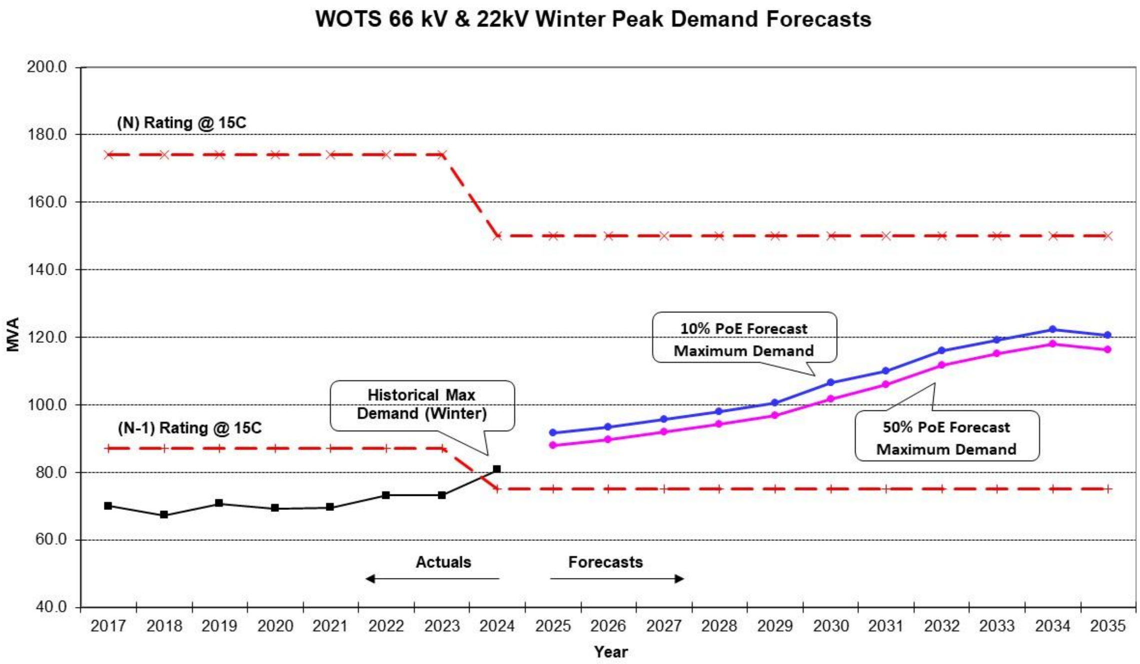
The summer maximum demand at WOTS 66 kV and 22 kV is expected to exceed 95% of the 50th percentile peak demand for 6 hours per annum. The station load has a power factor of 0.98 at maximum demand and load on the transformers is further supported by 22 kV capacitor banks installed at the station.

In relation to minimum demand, it is estimated that:

- For 5 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.992 at the time of minimum demand.

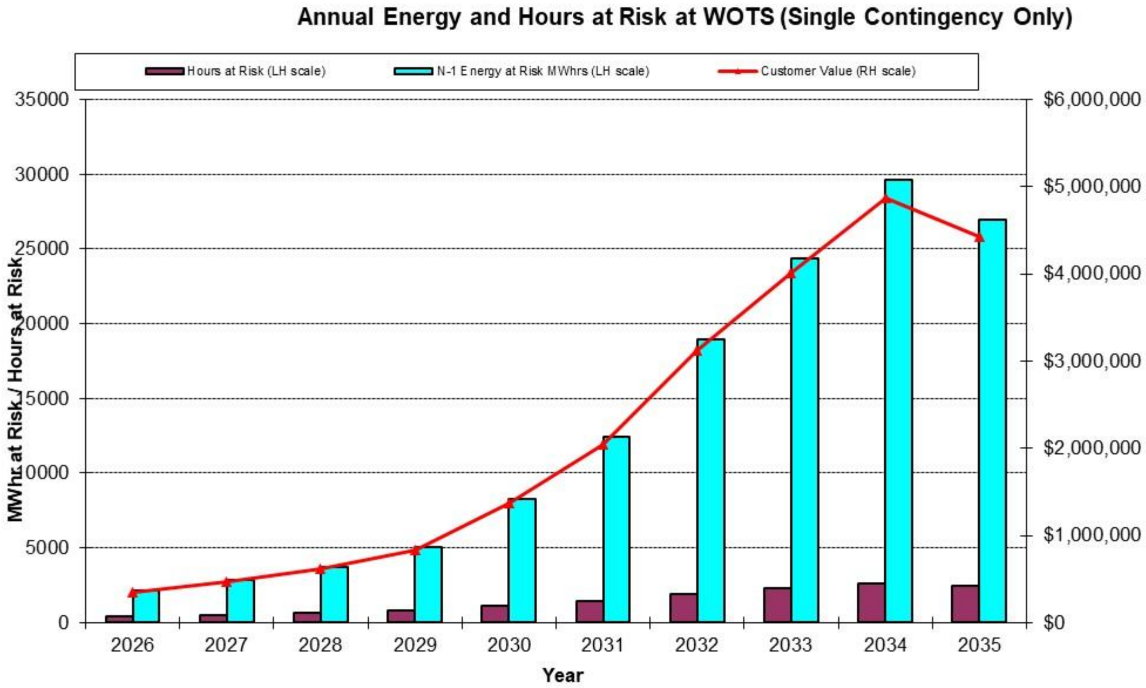
The combined 66 kV and 22 kV maximum demand at WOTS is not expected to reach the "N" summer station import rating within the 10-year planning horizon, but it presently exceeds the "N-1" import rating at the 50th and 10th percentile summer demand level, and is forecast to continue to do so. Maximum demand on the individual 66 kV and 22 kV windings is well within the ratings of the individual windings.

Similarly, the combined 66 kV and 22 kV winter maximum demand already exceeds the “N-1” winter station import rating but is not expected to reach the “N” import rating within the 10-year planning horizon. Currently, the winter maximum demand is lower than the summer maximum demand. However, it is forecast that by 2031, the 50th percentile winter maximum demand (101.6 MVA) will exceed the summer maximum demand (99.7 MVA).



Minimum demand levels remained well within the station’s operational “N” and “N-1” export ratings. This trend is expected to continue into the future under both 50th percentile and 10th percentile minimum demand forecasts over the 10-year planning period. There is therefore not expected to be any need for augmentation to alleviate export constraints over the 10-year planning period.

The bar chart below depicts the energy at risk with one transformer out of service (i.e., “N-1” risk) for the 50th percentile maximum demand forecast (both summer and winter), and the hours each year that the 50th percentile summer or winter maximum demand forecast is expected to exceed their “N-1” import ratings. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast. The VCR at the station is $37,955 per MWh.



Comments on Energy at Risk - Assuming HPS generation is not available

Key statistics for 2034/35 under "N-1" outage conditions – assuming HPS generation is not available - are summarised in the table below.

	MWh	Valued at VCR
Energy at risk at 50th percentile maximum demand forecast	26,933	$1022 million
Expected unserved energy at 50th percentile maximum demand	45	$1.70 million
Energy at risk at 10th percentile maximum demand forecast	37,067	$1407 million
Expected unserved energy at 10th percentile maximum demand	62	$2.34 million
70/30 weighted expected unserved energy value (see below)	**50**	**$1.90 million**

Due to the fact that the 330/66/22 kV transformers at WOTS were the only examples of their type in Victoria with this particular voltage ratio, an additional dedicated 330/66/22 kV transformer is stored at the terminal station as a cold spare. As such, due to the dedicated nature of this spare, the standard 2.65-month "Major Outage" duration (as explained in section 4.7) does not apply. A one-month outage duration has been applied instead at WOTS, which modifies the expected unavailability per transformer per annum to 0.083%.

Under the probabilistic planning approach[125], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.083%, as explained above) to determine the expected unserved energy cost in a year due to a major transformer

125 See section 3.1.

outage[126]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

The above table shows estimates of expected unserved energy for the 10th and 50th percentile maximum demand forecasts. Under its probabilistic planning approach, AEMO calculates a single weighted average expected unserved energy estimate by applying weights of 0.7 and 0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[127]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034/35 is $1.90 million.

If one of the 330/66/22 kV transformers at WOTS is taken off line during peak loading times and the "N-1" station import rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is enabled by AusNet Transmission Group's TOC[128] to protect the connection assets from overloading[129], 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 import 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.

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 TransGrid's 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 10-year planning horizon for the 50th or 10th percentile summer maximum demand forecasts.

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126 The probability of a major outage of one transformer occurring is 1.0% per transformer per annum.

127 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au)

128 Transmission Operation Centre.

129 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.

Feasible options for alleviation of constraints

The maximum demand at WOTS has remained relatively flat in recent years, however the forecast shows a gradual increase over the 10-year planning horizon. Actual maximum demand at WOTS will continue to be monitored, and if maximum demand increases above forecast, then action will be taken 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 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 may investigate demand management, through either special tariff incentives or a demand management aggregator, to assess these alternatives to network augmentation.

4. Embedded generation

As discussed above, subject to available water HPS can provide up to 58 MVA of network support to WOTS.

5. Place the spare transformer at WOTS into service

As mentioned above, an additional dedicated 330/66/22 kV 75 MVA transformer has been stored at the terminal station as a cold spare since 2023. The scope of work involved in placing the spare transformer into service would include double switching of the third transformer on the 330 kV side and connections into the WOTS 66 kV and 22 kV buses.

6. Fine tuning OSSCA

OSSCA scheme settings are reviewed annually to minimise the impact on customers of any load-shedding that may take place to protect the connection assets from overloading.

In the event of major outage, the WOTS spare transformer would be repositioned and installed within the terminal station to provide service. The expected outage duration in this scenario is 1 month.

Preferred network option for alleviation of constraints

AusNet Services completed the Regulatory Investment Test for Transmission (RIT-T) in December 2024. The preferred option involves the installation and commissioning of the WOTS spare transformer (330/66/22 kV 75 MVA) as the third in-service transformer at WOTS. The estimated capital cost of this work is $26 million, which equates to an indicative annualised total cost of $2 million. Based on the present demand forecasts, this project is unlikely to be economically justified before 2035. Accordingly, this project is currently on hold and under review.

The table on the following page provides more detailed data on the station rating, maximum and minimum demand forecasts, export constraints, energy at risk and expected unserved energy assuming embedded generation is not available.

WODONGA TERMINAL STATION 66kV and 22kV Loading (WOTS)
Detailed data: System normal maximum and minimum demand forecasts and limitations

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

Normal cyclic import rating with all plant in service	150	MVA via 2 transformers (Summer peaking)
Summer import N-1 Station Rating	75	MVA [See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating	75	MVA
Normal export rating with all plant in service	150	MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	75	MVA [See Note 7 below for interpretation of Export rating]

Import	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
50th percentile Summer Maximum Demand (MVA)	95.6	96.2	96.4	96.8	97.9	99.7	99.7	102.3	103.7	105.2
50th percentile Winter Maximum Demand (MVA)	89.6	91.8	94.1	96.8	101.6	106.0	111.6	115.0	118.1	116.3
10th percentile Summer Maximum Demand (MVA)	103.0	103.6	104.2	104.7	105.5	107.4	109.4	111.4	112.3	113.6
10th percentile Winter Maximum Demand (MVA)	93.4	95.7	97.9	100.6	106.7	110.1	115.9	119.2	122.3	120.6
N - 1 energy at risk at 50th percentile demand (MWh)	2,123	2,857	3,719	5,051	8,306	12,444	18,973	24,388	29,655	26,933
N - 1 hours at risk at 50th percentile demand (hours)	432	532	632	794	1,112	1,459	1,940	2,284	2,582	2,451
N - 1 energy at risk at 10th percentile demand (MWh)	4,496	5,596	6,937	8,812	14,305	18,653	27,560	33,747	39,767	37,067
N - 1 hours at risk at 10th percentile demand (hours)	704	843	984	1,159	1,628	1,970	2,539	2,892	3,174	3,076
Expected Unserved Energy at 50th percentile demand (MWh)	3.5	4.8	6.2	8.4	13.8	20.7	31.6	40.6	49.4	44.9
Expected Unserved Energy at 10th percentile demand (MWh)	7.5	9.3	11.6	14.7	23.8	31.1	45.9	56.2	66.3	61.8
Expected Unserved Energy value at 50th percentile demand	$0.13M	$0.18M	$0.24M	$0.32M	$0.53M	$0.79M	$1.20M	$1.54M	$1.88M	$1.70M
Expected Unserved Energy value at 10th percentile demand	$0.28M	$0.35M	$0.44M	$0.56M	$0.90M	$1.18M	$1.74M	$2.13M	$2.52M	$2.34M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.18M	$0.23M	$0.30M	$0.39M	$0.64M	$0.91M	$1.36M	$1.72M	$2.07M	$1.90M
Export	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
10th percentile minimum Demand (MVA)	-23.7	-26.1	-28.0	-29.4	-30.5	-31.2	-31.6	-31.9	-32.1	-32.3
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected volume of export energy curtailed for N-1 (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The summer 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 1 month for WOTS due to the dedicated on site cold spare transformer. The outage probability is derived from the base reliability data given in Section 4.7

5. The value of unserved energy is derived from the VCR relevant climate zone and sector values given in the AER VCR December 2024 final determination, 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
7. Station export rating is determined based on transformer nameplate rating. It has not factored in any other limitations such as voltage rise or other equipment limitations, which may necessitate the adoption of a lower export rating.