2024 TRANSMISSION CONNECTION PLANNING REPORT

Produced jointly by the Victorian Electricity Distribution Businesses

AusNet

united energy

Powercor AUSTRALIA

CITIPOWER

Jemena

2024 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 applied by the Australian Energy Market Operator (**AEMO**) in planning the Victorian shared transmission network[5]. 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

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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 216, effective from 5 September 2024.

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 See: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf

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.

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 50^{th} and 10^{th} 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 2024 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 AEMO 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.

- Dasun De Silva, Senior Manager – Network Development and Planning, 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[6] (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)	2028	63.5 MWh in 2028 ($3.2 million)	Nil over the ten-year planning horizon	Install additional transformation capacity and reconfigure 66 kV exits at ATS or BLTS	$2.7 million	Demand reduction; Local generation.
Altona no 3 & 4 (ATS West) 66 kV	2028	409.4 MWh in 2028 ($16.6 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.
Ballarat (BATS)	Not before 2034	2.1 MWh in 2034 ($0.09 million)	17 MWh in 2034 (Immaterial value)	Install a third 150 MVA 220/66 kV transformer.	$2.7 million	Demand reduction; Local generation
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 2034	0.47 MWh in 2033 ($20,470)	2 MWh in 2034 (Immaterial value)	Install an additional 150 MVA 220/66 kV transformer.	$2.7 million	Demand reduction; Local generation
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.					
Cranbourne 66 kV (CBTS 66 kV)	2026/27	101 MWh in 2026/27 ($3.99 million)	Nil over the ten-year planning horizon	Install a fourth transformer.	$3.5 million	Demand reduction; Local generation.
Deer Park (DPTS)	2027	90.3 MWh in 2027 ($4.2 million)	Nil over the ten-year planning horizon	Install an additional transformer. Powercor will commence the pre-feasibility studies to assess options to address this limitation, including a RIT-T if necessary prior to the next TCPR.	$2.7 million	Demand reduction; Local generation.

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

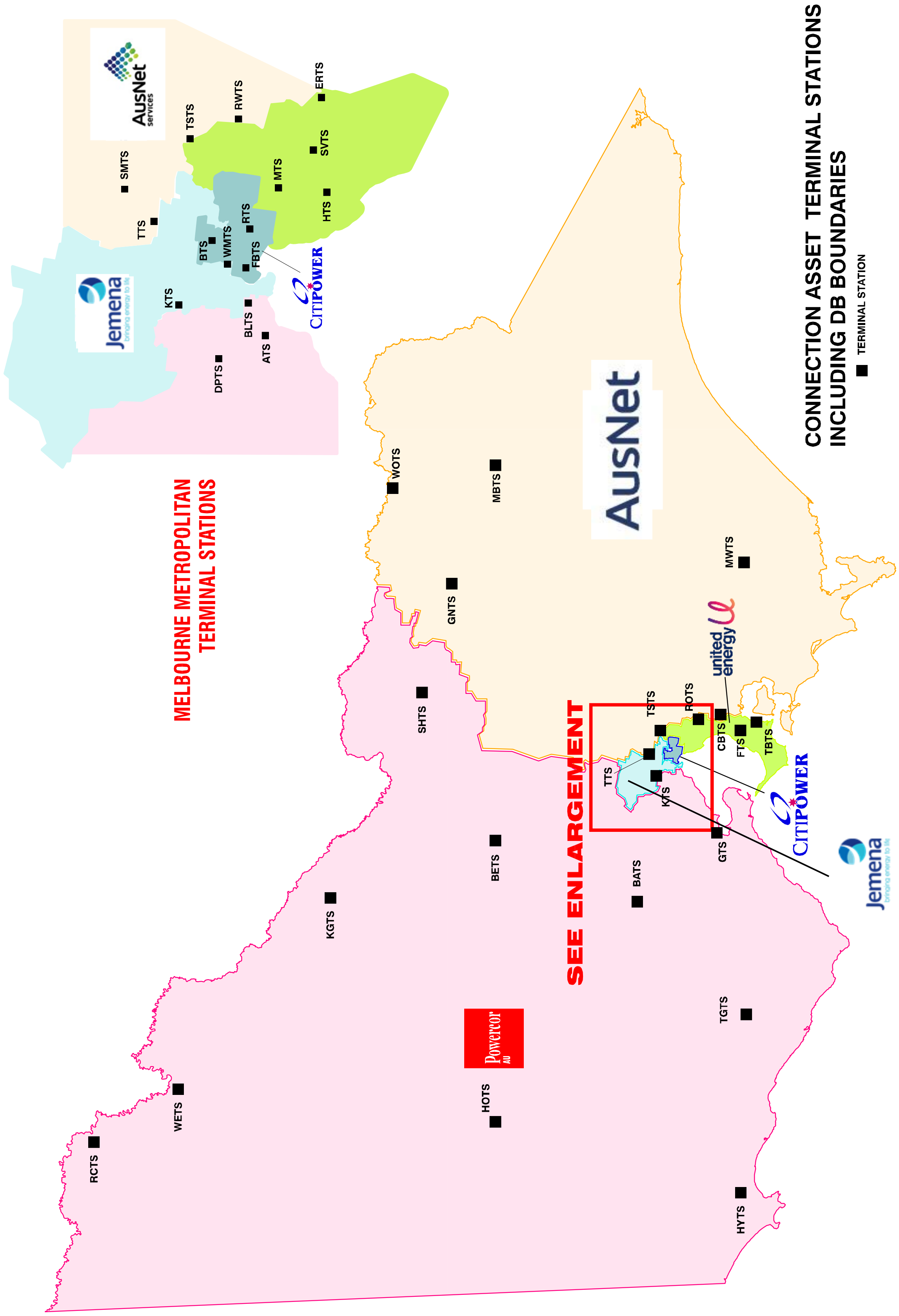
Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[6] (in MWh, and valued at VCR)	Expected embedded generation output curtailed (in MWh)	Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
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)	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.					
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 2034	0.83 MWh in 2034 ($37,000)	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
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 2034 there is projected to be maximum of 116.8 MVA of embedded generation at risk of being constrained off. This equates to an expected volume of export energy curtailed of 898 MWh in 2034. 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.					
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)	2028	356 MWh in 2028 ($17 million)	Nil over the ten-year planning horizon	Upgrade transformation capacity at KTS (B1,2,5) group, and install additional transformation capacity at KTS (B3,4) group	$7.1 million	Demand reduction; Local generation
Kerang (KGTS)	No demand-driven augmentation of import capacity is expected to be required within the ten-year planning horizon. By 2034, at the 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 2034, 126 MVA of generation is at risk of curtailment (equating to an expected volume of generation curtailment of 255 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.					

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[6] (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
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 no more than 4 hours, as the “hot spare” transformer at the station is brought into service. At a cost of approximately $2 million, it would not be economic to install full switching of the hot spare transformer at MBTS 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.					
Morwell (MWTS)	Unlikely to be before 2034	21.5 MWh in 2034 ($0.9 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 2034.	Demand reduction; Local generation
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.					

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[6] (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
Red Cliffs 66 kV (RCTS 66 kV)	Not before 2034	Minimal amounts over the forecast period. Implementation of AusNet Transmission's asset renewal plan will mitigate any load at risk after 2027.	7,546 MWh in 2034 (unlikely to be of sufficient value to economically justify any transmission connection augmentation)	Demand-driven augmentation is unlikely to be economic over the ten-year planning horizon. A contingency plan to transfer approximately 25 MVA from RCTS 66 to WETS will be implemented in the event of the loss of one of the RCTS 220/66 kV transformers. 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
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)	Not before 2034	2 MWh in 2034 ($89,000)	Nil over the ten-year planning horizon	Install a fourth transformer at RTS 66 kV.	$2.7 million	Demand reduction Embedded generation
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.					
Ringwood 66 kV (RWTS 66 kV)	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 2031/32. 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.					
Shepparton (SHTS)	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 2034, approximately 87 MVA of embedded generation is at risk of curtailment for the loss of one transformer. This equates to 517 MWh of energy at risk of curtailment, corresponding to an expected volume of curtailed energy of approximately 3.4 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.					

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[6] (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
South Morang (SMTS)	2026	130 MWh in 2026 assuming no generation from Somerton PS ($5.4 million)	Nil over the ten-year planning horizon	Install a third 225 MVA 220/66 kV transformer at SMTS.	$3.4 million	Demand reduction Embedded generation
Springvale (SVTS)	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.					
Templestowe (TSTS)	Not before 2034	1.3 MWh in 2034 ($44,880)	Nil over the ten-year planning horizon	Install a fourth 150 MVA 220/66 kV transformer at TSTS.	$3.5 million	Demand reduction; Local generation
Terang (TGTS)	Not before 2034	13.5 MWh in 2033 ($0.6 million)	5 MWh in 2034 (Immaterial value)	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.	$2.7 million	Demand reduction; Local generation
Thomastown (TTS)	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.					
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 minimum demand exceeds the N-1 export rating as WETS. In the event of a transformer outage at WETS, embedded generators may need to reduce generation to avoid overloading the remaining transformer. By 2034 there is projected to be 75 MVA of embedded generation at risk of being constrained off. This equates to an expected volume of export energy curtailed of 200 MWh in 2034. 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.					

Terminal Station	Indicative timing for preferred network solution (using VCR)	Expected unserved energy[6] (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
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)	2026/27, to enable the connection of additional renewable generation in the WOTS area.	1.4 MWh in 2034 ($0.07 million) excluding generation from Hume PS or any other source	See PACR for WOTS Connection Enablement RIT-T	The RIT-T PACR published in December 2024 identifies the installation of the WOTS spare transformer (330/66/22 kV 75 MVA) as part of a suite of works to enable the connection of additional renewable generation to the WOTS sub-transmission system.	$2.4 million	Demand management


CONNECTION ASSET TERMINAL STATIONS
INCLUDING DB BOUNDARIES
TERMINAL STATION
MELBOURNE METROPOLITAN
TERMINAL STATIONS
SEE ENLARGEMENT
AusNet
AusNet services
Jemena
CitiPower
united energy
Powercor
SMTS
TSTS
RWTS
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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[7] 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[8]; and
- AEMO is responsible for planning and directing the augmentation of the shared transmission network.

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.

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

8 The shared transmission network 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.

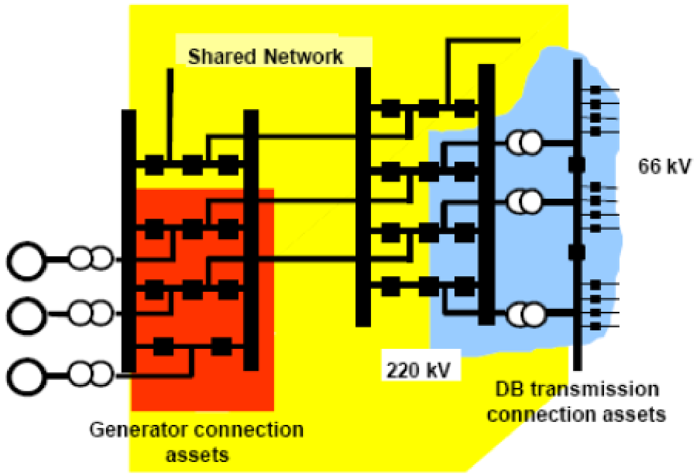

Figure 1: Shared network and connection assets in a notional network

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[9]. 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**) authorises AEMO to exercise declared shared network functions in Victoria. In this regard, AEMO's functions include: "*to plan, authorise, contract for, and direct, augmentation of the declared shared network*", where the declared shared network is defined as "*the adoptive jurisdiction's [in this case, Victoria's] declared transmission system excluding any part of it that is a connection asset within the meaning of the Rules*".

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

The MoU sets out a framework for cooperation and liaison between AEMO and the DBs regarding the joint planning of the shared transmission network and transmission connection assets in Victoria. In particular, the MoU sets out the approach to be applied by AEMO and the DBs in assessing options to address limitations in a distribution network where one of the options consists of investment in dual function assets or transmission investment, including connection assets and the shared transmission network.

Under the MoU, the DBs and AEMO have agreed that subject to the thresholds set out in the Rules, joint planning projects should be assessed by applying the RIT-T.

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.

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

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[10] sets out provisions governing the planning and development of networks. Those provisions require, among other things, Transmission and Distribution Network Service Providers to:

10 Version 216 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, the DBs and AEMO have agreed that joint planning projects involving transmission connection and distribution investment should be 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[11]. 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 1A: 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.

11 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(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 joint planning results.
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**)[12] 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 these 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 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

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

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 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 network constraints identified in this report are encouraged to lodge expressions of interest with the relevant DB(s).

Proponents of non-network proposals should make initial contact with the relevant DB as soon as possible, to ensure that sufficient time is available 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 to AEMO

Where a network solution requires new connection points with the shared transmission network to be established, a connection agreement with AEMO is required in accordance with clause 5.3 (Establishing or Modifying Connection) of the Rules. As explained in section 1.2, the assets that form part of the Victorian declared shared transmission network fall under the planning jurisdiction of AEMO. 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 AEMO at the connection application stage.

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

A more detailed overview of the Victorian transmission connections process is available from AEMO's website at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/victorian-transmission-connections.

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 AEMO 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 AEMO on the same site, it may become necessary to invite AEMO to participate in the town planning process at the same time so that both the council and the public are made aware of the entire proposed development on the site.

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

1.5.5 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 highlight the need for the project and the resultant benefits to the community, and invitation of public comments on the proposal.

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

1.5.6 Project Implementation

As noted in section 1.3.1, the DBs are required by the Victorian 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 asset augmentation works. These requirements are assessed through the joint planning process, which involves AEMO, AusNet Transmission Group and the DBs in Victoria.

- 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 AEMO, 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 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.

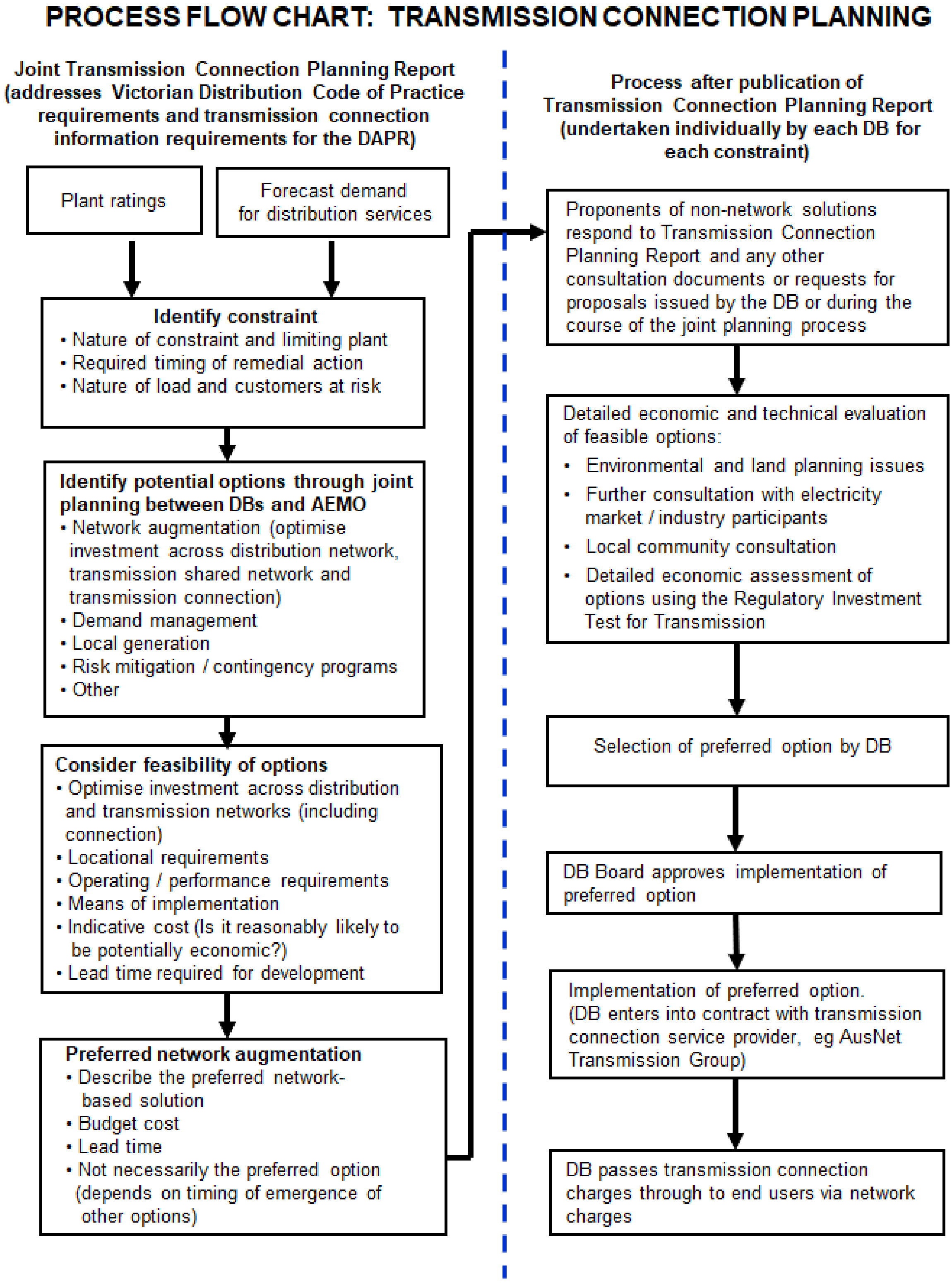

Figure 2: Process Flowchart – Transmission Connection Planning

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. The growth of renewable energy systems in diverse geographic areas - including remote locations where renewable resources are abundant - is creating additional supply hubs that are increasing bi-directional power flows and altering flow patterns across the Victorian transmission network. These developments continue to impact system stability and the operational complexity of the power system.

During 2023/24, rooftop solar produced more than 9% of Victoria's electricity generation, with 4,847 MW of small-scale rooftop photovoltaic (**PV**) capacity. By June 2024, a total of 537 MW of battery storage capacity had been commissioned in Victoria, along with 5,409 MW of large-scale wind and solar capacity.[13]

As household and business consumers continue to install their own PV generation and storage systems, Victoria's minimum grid demand continued to decline, creating a range of challenges associated with the secure operation of the power system. AEMO has reported that Victoria recorded its all-time lowest minimum operational demand of 1,594 MW on 31 December 2023. This was 601 MW lower than the previous record, and the fifth consecutive year that the record has been broken. At the time of the record minimum demand, more than 3,000 MW of distributed PV supplied the majority of Victoria's underlying demand[14].

The 2024 Victorian Annual Planning Report (VAPR)[15] notes that the rapid changes in Victoria's energy landscape are being driven by consumer choices, energy market participant choices, and state and federal government policies and regulations. The main changes shaping the state's transmission needs over the next decade are:

- The geographic location of supply continues to diversify. Historically, Victoria's electricity principally came from large brown coal generators in the Latrobe Valley, in the east of the state. Now, and increasingly in future, supply comes from renewable resources concentrated in the west, and across interconnectors throughout Victoria.

- The latest forecasts indicate higher electricity maximum demand for the next five years. This is driven by homes and businesses switching from gas to electricity, and a forecast increase in demand from data centres.

- Minimum demand from the grid continues to decline. As consumers' distributed PV investments keep growing and meeting more of their energy needs, the low and declining levels of grid demand create a range of challenges to ensure secure operation of the power system.

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 AEMO's 2024 VAPR and other sources.

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

14 AEMO, 2024 Victorian Annual Planning Report, October 2023, page 5.

15 See 2024-victorian-annual-planning-report.pdf

2.2 Government policy announcements and emission reduction targets

In August 2024, the Victorian Government published *Cheaper, Cleaner, Renewable: Our Plan for Victoria's Electricity Future.*[16] The document forecasts that by 2035:

- Electricity use will increase by about 50% compared to 2024, driven by the electrification of homes and businesses, uptake of EVs, and new industrial load growth.
- Around 4.8 GW of emissions-intensive coal-fired power generation will have closed.
- There will be an increasing amount of electricity use through the conversion of gas products to electricity and through transport, with the addition of 1.4 million EVs and an equal amount of charging ports. EVs will consume 8 terawatt hours of electricity every year, while an additional 7 terawatt hours of annual electricity consumption will be associated with electrification - gas usage that will be replaced with electricity.
- To support this increase in consumption, about 11.4 GW of new grid-scale renewable generation projects (including 4 GW of offshore wind) will need to be connected to the Victorian transmission and distribution networks, with a total of 222 offshore wind turbines and 900 additional land- based turbines.
- Around 7.6 GW of additional rooftop solar (an extra 27 million solar panels) and 6.3 GW of short and long duration storage will be installed, including behind-the-meter batteries, demand-side participation and smaller front-of-meter assets such as neighbourhood batteries.
- 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.

2.3 Reverse power flows at terminal stations

AEMO's 2024 Victorian Network Performance and Insights Report[17] notes that an increasing number of distributed generators (including distributed PV) connecting at the

[16] Our plan for Victoria's electricity future (energy.vic.gov.au)

[17] See 2024-victorian-network-performance-and-insights-report.pdf

distribution level has led to reverse power flows at some terminal stations, which were originally established to supply customer loads.

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 to the DSN, reversing the traditional flow where the distribution network typically draws from the DSN. The reverse power flow conditions together with lightly loaded transmission lines lead to operational issues in voltage management in the DSN, due to lack of reactive support and/or onload tap ranges available at the connection points.

In the past year, reverse power flows occurred at 16 terminal stations, one more than in 2022-23, with Geelong Terminal Station experiencing a half-hour reverse flow for the first time. The total reverse flow hours were similar to what was observed in 2022-23, decreasing only slightly to 19,114 hours from 19,533 hours.

Table 1B below (reproduced from the 2024 Victorian Network Performance and Insights Report) shows the terminal stations and the number of hours that reverse flows occurred over the last five years, and the primary cause of those reverse flows.

Table 1B: Annual statistics of reverse flows at identified terminal stations

Terminal station	Hours with reversed flows						Primary cause
	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	
Wemen 220/66 kV	1,926	3,241	3,546	3,053	3,610	3,082	Distribution network connected generation
Terang 220/66 kV	2,288	2,905	2,343	2,626	2,350	1,805	Distribution network connected generation
Kerang 220/66/22 kV	2,504	2,646	2,657	2,606	2,999	2,974	Distribution network connected generation
Horsham 220/66 kV	1,358	827	290	680	426	319	Distribution network connected generation
Red Cliffs 220/66/22 kV	536	477	1,933	2,192	2,636	2,121	Distribution network connected generation
Shepparton 220/66 kV	0	940	1,534	1,551	1,445	1,369	Distribution network connected generation
Ballarat 220/66 kV	0	838	1,912	1,659	1,589	1,395	Distribution network connected generation
Glenrowan 220/66 kV	0	0	592	2,582	2,617	2,739	Distribution network connected generation
South Morang 220/66 kV	0	0.5	14	56	84	266	Distribution network connected generation
Mount Beauty 220/66 kV	579	0	12	1,632	1,343	1,767	Distribution network connected generation
Bendigo 220/66 kV	0	0	4	24	39	144	Distributed PV
Cranbourne 220/66 kV	0	0	0	4	15	254	Distributed PV
Deer Park 220/66kV	0	0	0	18	35	203	Distributed PV
Morwell 220/66kV	0	1	2	38	66	137	Distribution network connected generation
Wodonga 330/22 kV	0	0	NA*	201	279	542	Distributed PV
Geelong 220/66 kV	0	0	0	0	0	0.5	Distributed PV
Total	9,191	11,876	14,839	18,922	19,533	19,114.5	

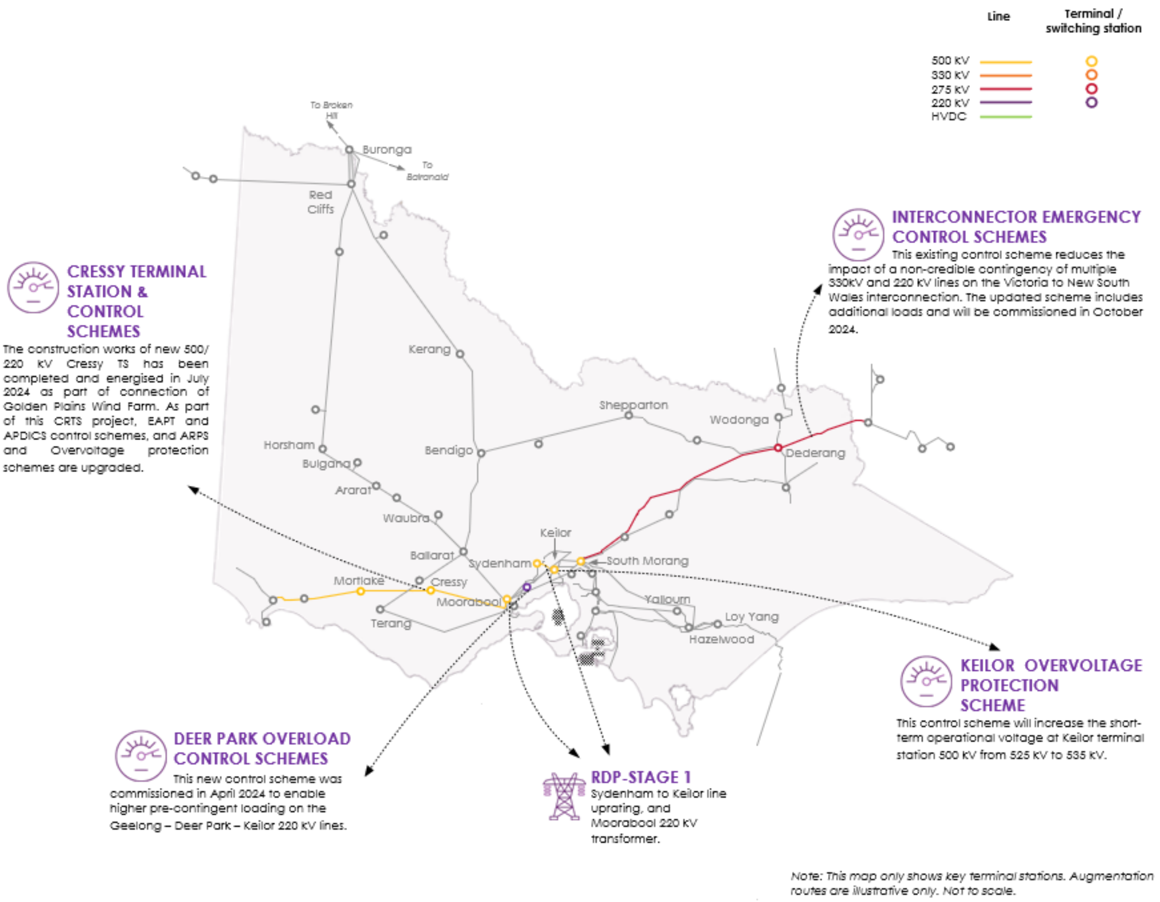
*Data quality issues prevented determination of reverse flow hours for this terminal station over this period.

Source: AEMO, 2024 Victorian Network Performance and Insights Report, page 20.

2.4 Transmission Development Plan for Victoria

AEMO's Transmission Development Plan for Victoria is designed to deliver security and reliability objectives in the context of Victorian Government policy. The investment projects presented in the plan help reduce overall costs to consumers by unlocking lower-cost generation supplies, maintaining supply reliability to Victorian consumers, ensuring power system resilience, and improving the efficiency of resource sharing between neighbouring regions. Delivering the investments outlined in the Transmission Development Plan is critically important to meet Victoria's energy reliability and security requirements.

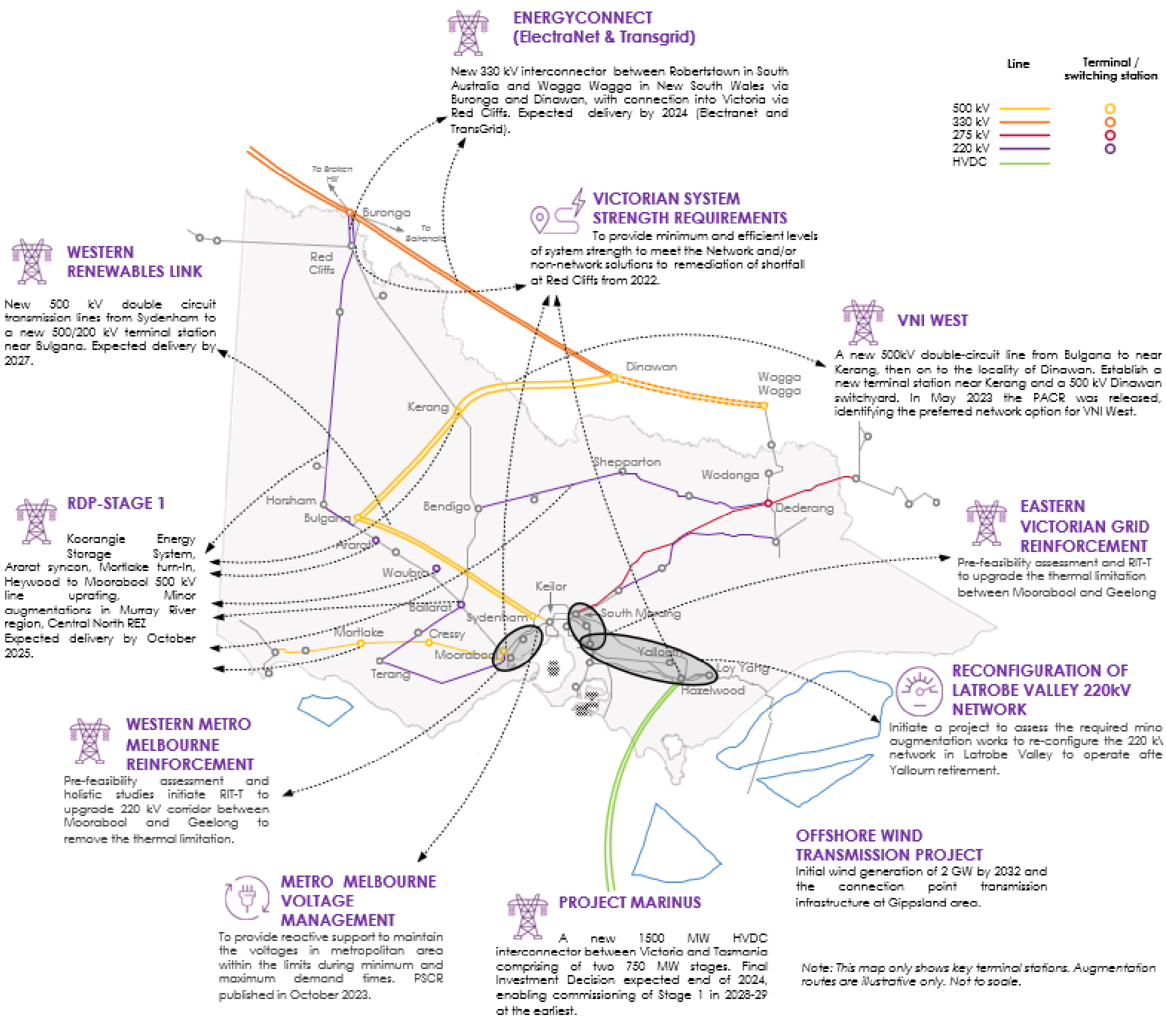
Transmission Development Plan projects that are near completion or have been completed recently are shown in Figure 3A below.



Source: AEMO, 2024 Victorian Annual Planning Report, page 37.

Figure 3A: Newly completed / near complete transmission projects for Victoria

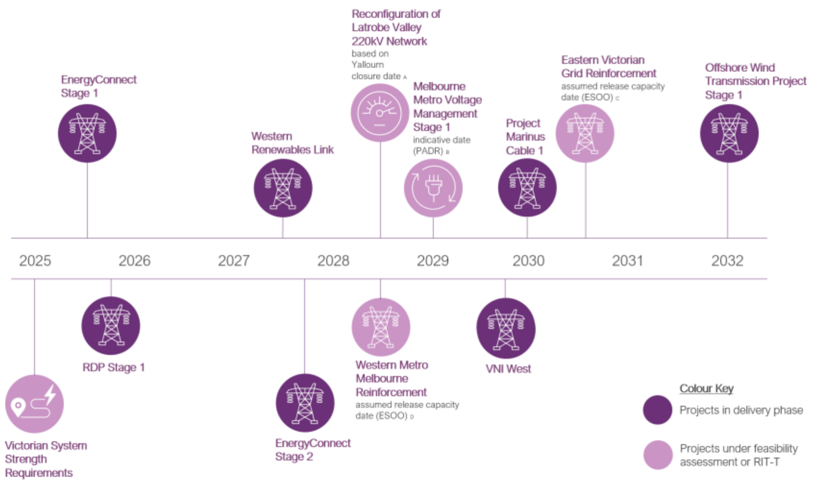
Projects that are currently in progress under the Transmission Development Plan for Victoria are shown in Figure 3B below.



Source: AEMO, 2024 Victorian Annual Planning Report, page 38.

Figure 3B: In-progress Transmission Development Plan projects for Victoria

The timeline for delivery of projects under the Transmission Development Plan is outlined in Figure 3C.



Source: AEMO, 2024 Victorian Annual Planning Report, page 39.

Figure 3C: Timeline of Transmission Development Plan projects for Victoria

The Transmission Development Plan for Victoria is consistent with AEMO's current Integrated System Plan (**ISP**) for the NEM, which was published in June 2024.[18] 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.

3 PLANNING METHODOLOGY

3.1 Transmission connection planning approach

The DBs' planning of transmission connection is focused in part on delivering an optimal level of supply reliability to customers[19]. 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); and
- indirect costs borne by customers as a consequence of 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 basic concept is illustrated in Figure 4 below.

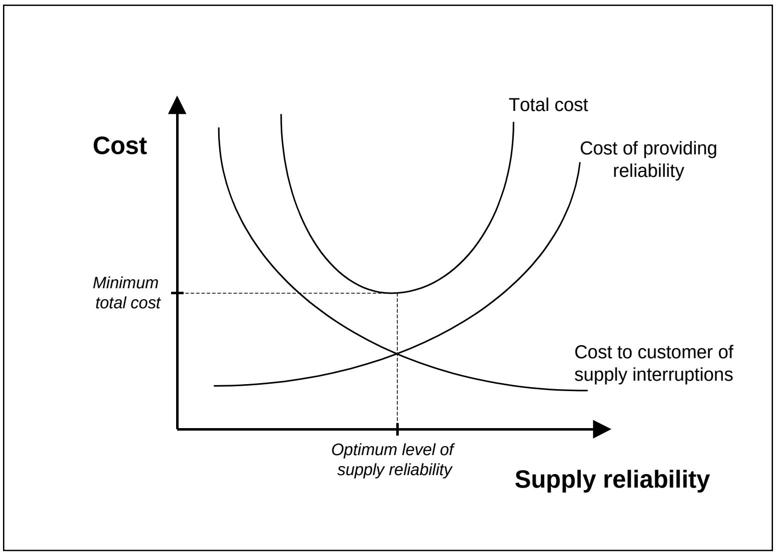


Figure 4: Balancing the trade-off between cost of service and reliability

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 decisions may include network and non-network solutions. This objective is

18 See AEMO | 2024 Integrated System Plan (ISP)

19 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 applies[20] to planning the shared transmission network[21].

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 load cannot be supplied 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 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.

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

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20 A copy of the Victorian transmission planning criteria can be obtained from AEMO's web site at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf

21 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.

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[22].

For this report, the DBs have adopted the VCR sector estimates published by the AER in its December 2023 Values of Customer Reliability Annual Adjustment[23]. These values are shown in the table below.

Table 1: VCR estimates by sector

Sector	**VCR for this report ($/kWh)** Source: AER 2023 VCR Annual Adjustment, December 2023
Residential (Victoria)	25.13[24]
Commercial (NEM)	52.20
Agricultural (NEM)	44.40
Industrial (NEM)	74.79[25]

The AER's estimates were determined before the COVID-19 pandemic, which may affect future VCR estimates. For example, since December 2019, there has been a significant increase in the number of people working from home, so the AER's current estimate of the residential VCR may be understated[26].

The AER's Final Report provides the following guidance on how the VCR should be applied[27]:

> "When applying the VCR, the value used should be reflective of the customer composition on the network. For example, network investment decisions should use a VCR reflective of the composition of customer types located on the feeder or substation, rather than the VCR for the region, to properly consider the competing tensions of reliability and affordability."

22 See: AER, Final Report on VCR values, December 2019, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/final-decision

23 See https://www.aer.gov.au/system/files/2023-12/2023%20VCR%20Annual%20Adjustment%20update%20summary%2816100739.1%29.pdf

24 The Victorian residential VCR is estimated for four different climate zones, as shown in Table 1.1 of the AER's Final Report. For simplicity, the value shown here is the composite Victorian residential VCR as per Table 1.2 of the AER's Final Report.

25 For customers with a maximum demand below 10 MVA, as per Table 1.3 of the AER's Final Report on VCR values, December 2019.

26 This consideration underscores the importance of sensitivity testing in investment decision analyses such as the RIT-T. Section 7.2 (page 84) of the AER's Final Report on VCR values suggests that sensitivity ranges of up to +/- 30 per cent of VCR estimates could be used.

27 AER, Final Report on VCR Values, December 2019, page 10.

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[28]. 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 new 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 expected to play a similar role to the VCR in evaluating the net benefit of reducing or removing network constraints. For instance, it is expected that the CECVs will be used to assess whether proposed steps to reduce export curtailment - such as increasing CER hosting capacity - can be economically justified.

In June 2022, the AER published its Customer Export Curtailment Value Methodology[29]. At the same time, the AER also published a DER[30] Integration Expenditure Guidance Note[31], which includes direction on how distribution network service providers should:

- develop business cases for network investment integrating higher levels of CER and quantify CER values;
- develop CER integration plans and investment proposals; and
- quantify CER benefits in a cost-benefit analysis.

It is possible that in the future, the new 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. This report identifies those terminal stations where export curtailment may be an issue. Further detailed analysis of whether export curtailment will justify additional investment in terminal station capacity will be undertaken as part of a RIT-T assessment.

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

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

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

31 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure-guidance-note/final-decision

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.[32] 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.[33] 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 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.

3.5 Planning standard applied by DBs

Clause 19.3.2(c) of the Victorian EDCoP requires this report to set out the DBs' transmission connection planning standards. As explained in section 1.1, this report assists in identifying emerging constraints at terminal stations that may warrant further detailed analysis in accordance with the requirements of the RIT - T. The purpose of the RIT-T is set out in clause 5.15A.1(c) of the Rules as follows:

> "The purpose of the regulatory investment test for transmission […] is to identify the credible option that maximises the present value of net economic benefit …."

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

32 Final decision | Australian Energy Regulator (AER)

33 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 section for each Terminal Station, except for Deer Park Terminal Station (DPTS)[34]:

- ***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[35] 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 4.6 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 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

34 At present, a spare 225 MVA transformer suitable for installation at DPTS is not available. The DB responsible for planning DPTS (CitiPower-Powercor) has adopted the conservative assumption that a major transformer failure would not be repairable, and therefore a replacement transformer would need to be procured. The procurement of a replacement would take 12 months, so in the case of DPTS, a major outage of a transformer is assumed to have a duration of 12 months.

35 The term “major outage” refers to an outage that has a mean duration of 2.65 months, typically due to a significant failure within the transformer. The actual duration of an individual major outage may vary from under 1 month up to 12 months. Further details are provided in section 4.6.

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 AEMO[36].

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[37].

4.2 Quantifying “energy at risk”

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

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

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

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

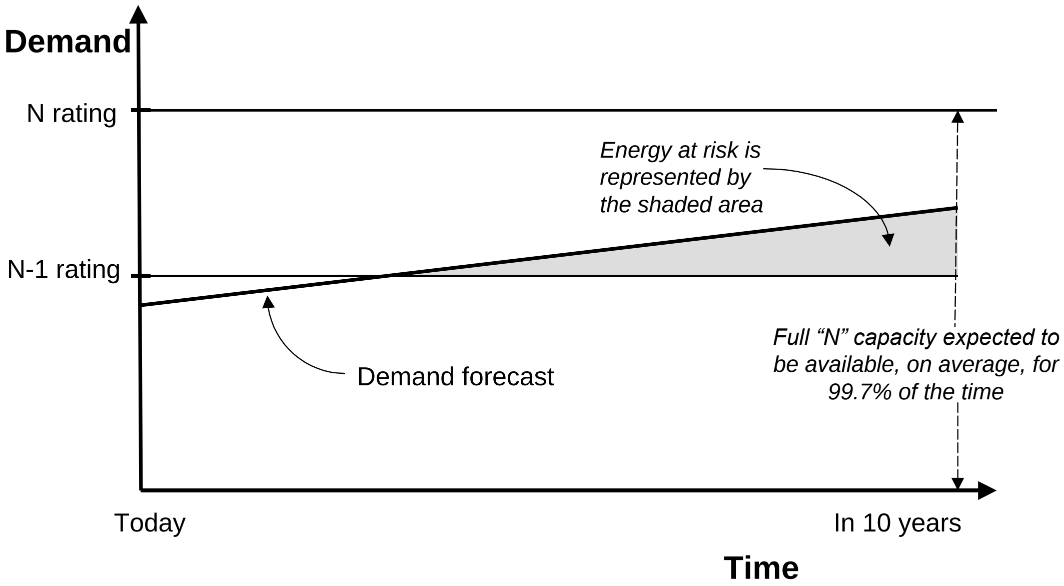

Figure 5: Relationship between N rating, N-1 rating and energy at risk

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

As a result of the increase in CER (discussed in Chapter 2), several terminal stations now experience reverse power flows. Reverse power 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 Services has advised that in these circumstances, the existing cyclic ratings may no longer apply to these transformers because they no longer exhibit a predictable cyclic loading pattern. Instead, it may be necessary to adopt the transformer's nameplate rating (rather than the higher cyclic rating) for planning and operational purposes.

AusNet Transmission Services reviews transformer load profiles on an ongoing basis and updates applicable ratings as required. The ratings of some stations with significantly changed load profiles, caused by either changing load patterns and/or significant generation connected, have recently been revised downwards. The relevant risk assessments presented in this report incorporate these changes.

4.3 Demand forecasts

The demand forecasts used in the preparation of this report are referred to as the Victorian Terminal Station Demand Forecasts (TSDF). The TSDF is prepared by the Victorian DBs and is 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 from, and capacity of, each transmission connection are presented for each terminal station in the individual risk assessments that form part of this report.

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[38], reducing the maximum demand at the transmission connection points.

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.

38 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.

4.6 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 basic reliability data for terminal station transformers has been established and agreed with the asset owner, AusNet Transmission Group. The base data focuses on:

- the availability of the connection point main transformers; and
- the probability of a major problem forcing these plant items out of service for an average period of 2.65 months. This does not include minor faults that would result in a transformer being unavailable for a short period of time (ranging from a few hours up to no more than two days).

The basic reliability data adopted to produce this report is summarised in the following table.

Table 2: Basic 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 average of major outage duration	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 strategic spare transformer, during which time, the transformer is not available for service.
Expected transformer unavailability due to a major outage per transformer-year	0.01 x 2.65/12 = 0.221% approximately	On average, each transformer would be expected to be unavailable due to major outages for 0.221% of the time, or 19 hours in a year.

In September 2024, AusNet Transmission Group's Principal Engineer, Strategic Network Planning 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[39]:

- 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,

[39] 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.

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 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 basic reliability data contained in this section.

A spare 225 MVA transformer suitable for installation at DPTS is not available. The DB responsible for planning DPTS (CitiPower-Powercor) has adopted the conservative assumption that a major transformer failure would not be repairable, and therefore a replacement transformer would need to be procured. The procurement of a replacement would take 12 months, so in the case of DPTS, a major outage of a transformer is assumed to have a duration of 12 months.

4.7 Availability of spare transformers

In September 2024, AusNet Transmission Group’s Principal Engineer, Strategic Network Planning advised that:

- Both 220/66 kV metropolitan spare transformers are available to manage the risk of a metro transformer failure and they are located at Thomastown and Heatherton terminal stations.

- Both 220/66/22 kV 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 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 is a small number of AusNet Transmission Group terminal stations for which a stock of spare transformers is not held. These are 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.

As noted in section 4.6, a spare transformer suitable for installation at DPTS is not available.

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 planning report assume normal network operating conditions, and therefore they show estimates of load at risk and expected unserved energy before any potential short-term load transfers. The reasons for this approach are:

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

- The capability of the distribution network to 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 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 Detailed risk assessments and options for alleviation of constraints, by terminal station

Set out on the following pages are the detailed risk assessments and a description of the options available for 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.

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%[40] 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 2028 to 2031 is less valuable today than one which defers a similar network augmentation from, say, 2025 to 2028. These issues should be considered by proponents of non-network solutions in assessing the implications of this report.

In addition, 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 easily be up to two to three years, taking into account the need to obtain local authority planning consent[41]. Given this consideration, the individual risk assessment commentaries for each terminal station will:

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

4.10 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 "2024/25", or "summer of 2024/25".

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 2024/25, for instance), the peak would typically be expected to occur in the second year (in this example, 2025), and the relevant data for 2024/25 would be shown in the accompanying tables and charts as 2025.

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40 In its 2023 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.

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

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 basic reliability data contained in Section 4.6.

Table A2: Expected Transformer Unavailability

Expected transformer unavailability due to major outage per transformer-year (Refer to Section 4.6 for the base 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)[42]	**D=A*A**	**0.00049%**

42 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.

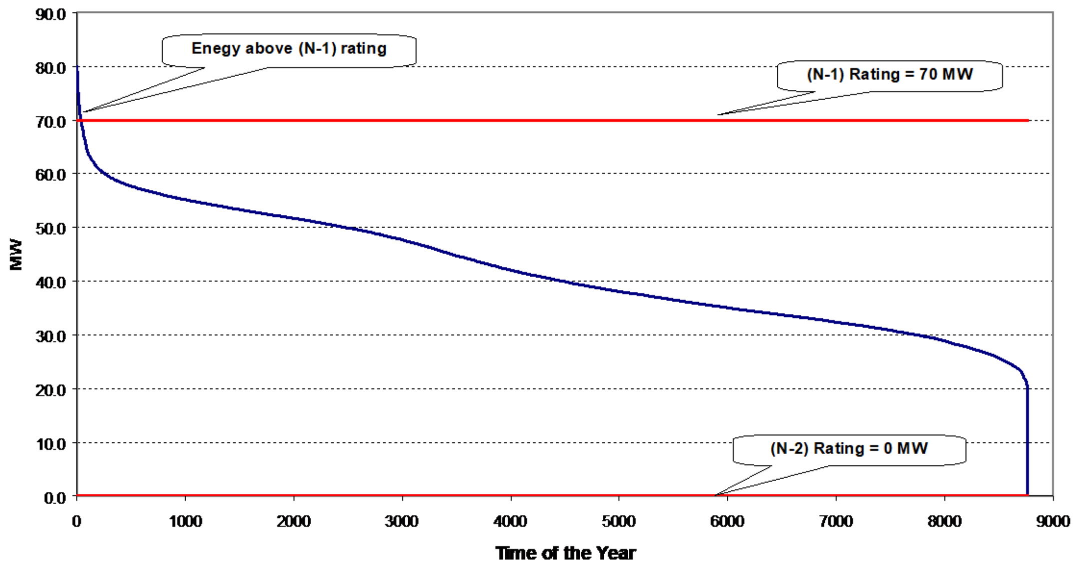


Figure A1: Annual Load Duration Curve

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.

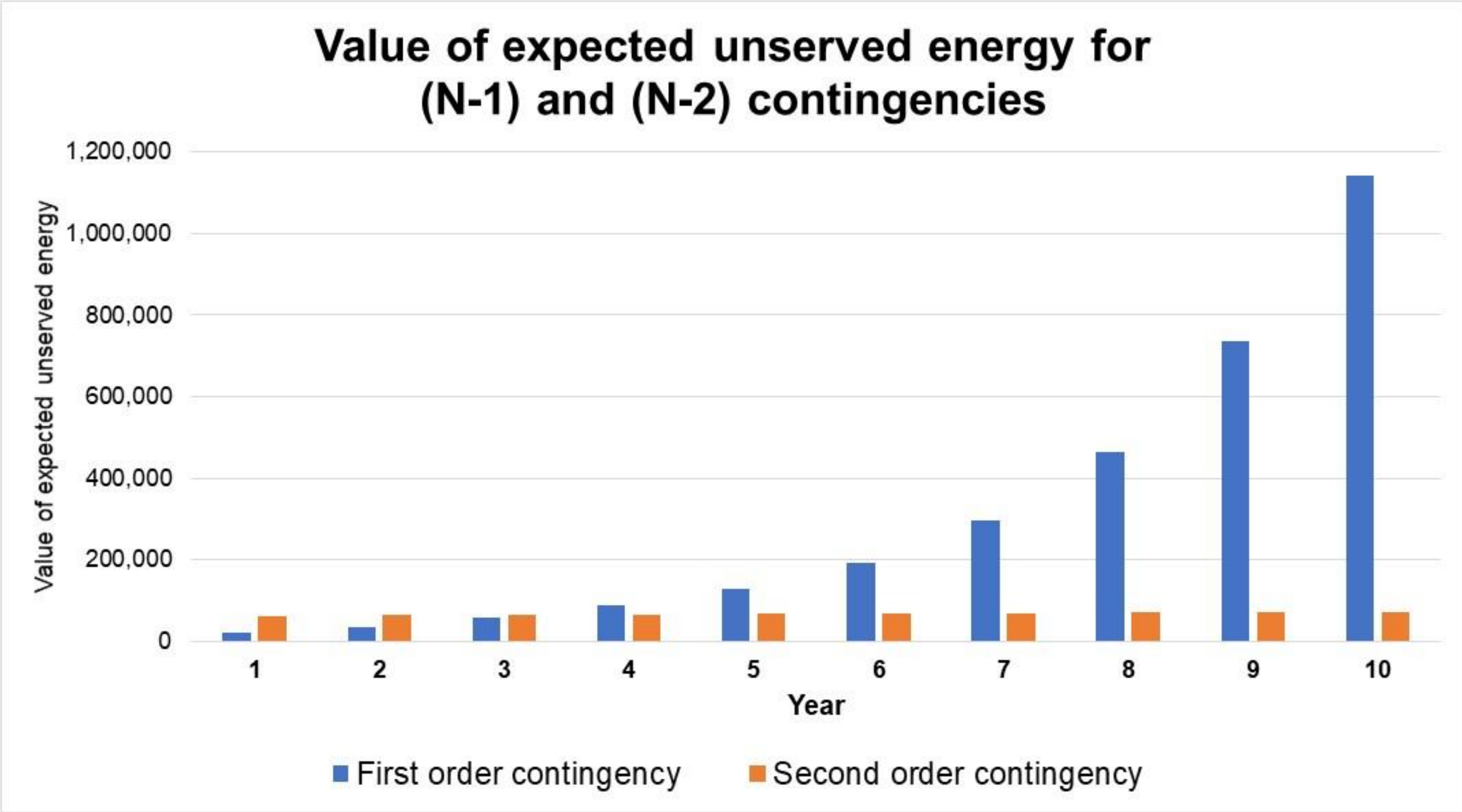


Figure A2: Value of expected unserved energy

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 INDIVIDUAL TERMINAL STATIONS (IN ALPHABETICAL ORDER)

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 63,346 customers. The station is shared by Jemena Electricity Networks (39%) and Powercor (61%).

Embedded generation

A total of 112 MW capacity of embedded generation is installed on the sub-transmission and distribution systems connected to ATS-BLTS. It consists of:

- 43 MW of large scale (>1 MW) embedded generation, which includes 40 MW in the Powercor distribution system and 3 MW in the Jemena distribution system; and
- about 69 MW small-commercial and residential rooftop solar PV (<1 MW), which includes 42 MW in the Powercor distribution system and 27 MW in the Jemena distribution system.

Magnitude, probability and impact of constraints

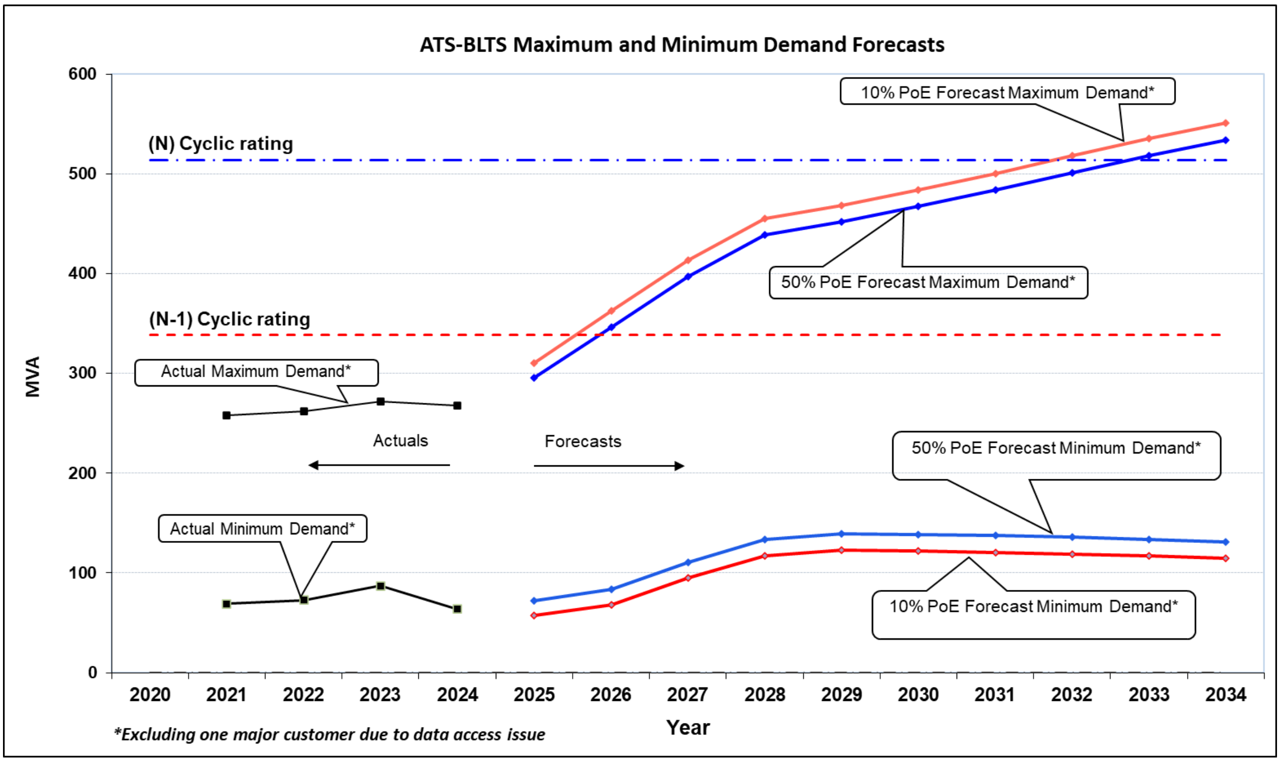
ATS consists of three 150 MVA 220/66 kV transformers with the 2-3 66 kV bus tie circuit breaker locked open to manage fault levels. Under these arrangements, only one ATS 150 MVA 220/66 kV transformer operates in parallel with the BLTS system. BLTS has two 150 MVA 220/66 kV transformers supplying the 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 253.4 MW (263.9 MVA) in summer 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 35°C ambient temperature. It is noted that at present, there is insufficient data available to enable the impact of all connections 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.

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 maximum demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of maximum demand is 0.96

In relation to minimum demand, it is estimated that:

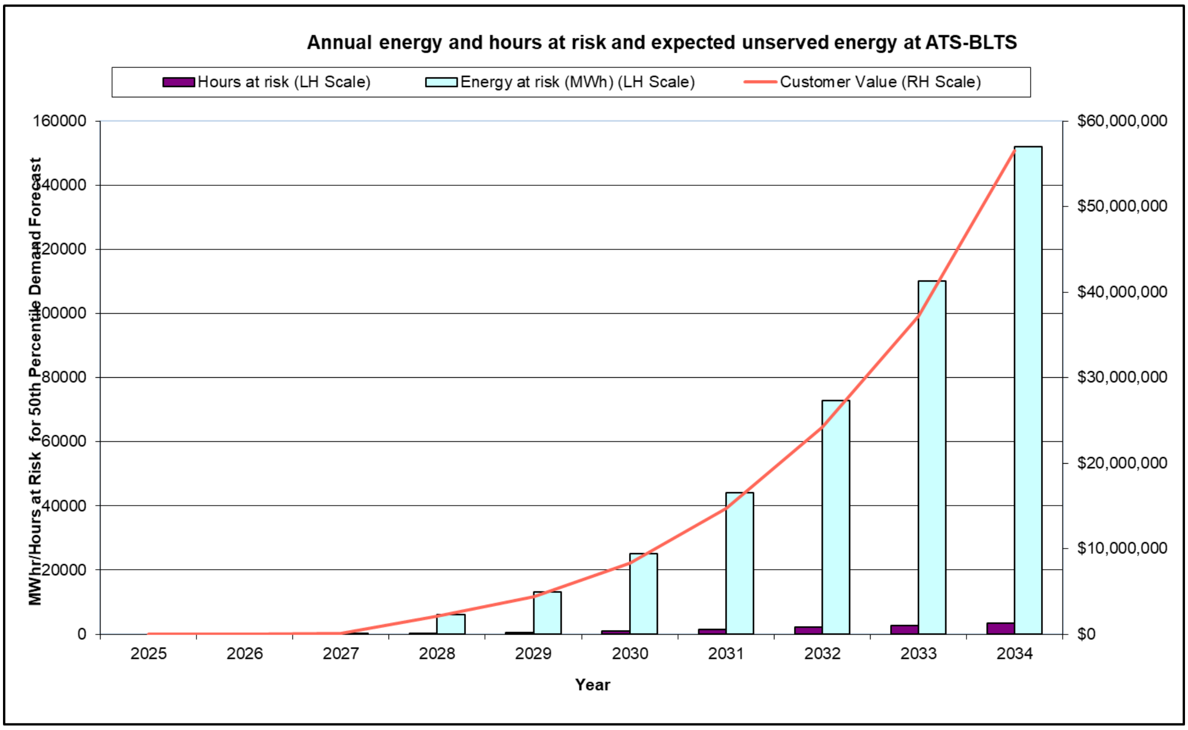
- For 10 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99

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 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 $51,115 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	6,191	$316 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	40	$2 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	18,105	$925 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	118	$6 million
70/30 weighted expected unserved energy value (see below)	**63.5**	**$3.2 million**

Under the probabilistic planning approach[43], 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[44]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

43 See section 3.

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

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)[45]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2028 is $3.2 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 2032 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[46] automatic load shedding scheme which is operated by AusNet Transmission Group's TOC[47] 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. 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 or BLTS 66kV 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-

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

46 Overload Shedding Scheme of Connection Asset.

47 Transmission Operation Centre

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.

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 - 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	514	via 3 transformers (summer)
Summer N-1 Station Import Rating:	339	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	386	
Summer N-1 Station Export Rating:	300	[See Note 7]
Winter N-1 Station Export Rating:	300	[See Note 7]

Import	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
50th percentile Summer Maximum Demand (MVA)	292.9	337.3	385.9	438.5	455.7	473.5	492.1	512.1	532.4	551.3
50th percentile Winter Maximum Demand (MVA)	295.2	346.5	397.1	438.8	451.9	467.3	483.6	500.9	518.0	533.5
10th percentile Summer Maximum Demand (MVA)	318.7	363.3	413.1	465.3	481.4	499.6	518.5	538.8	559.1	578.3
10th percentile Winter Maximum Demand (MVA)	310.4	362.4	413.6	455.3	468.4	484.2	500.7	518.3	535.7	551.2
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	309.8	6190.9	13100.4	25152.7	44179.3	72804.7	110139.8	151966.2
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	23.5	331.0	602.3	996.8	1528.5	2163.5	2791.3	3348.5
N-1 energy at risk at 10% percentile demand (MWh)	0.0	56.8	1610.0	18104.5	30804.1	51283.9	80082.7	119268.3	166571.1	217105.0
N-1 hours at risk at 10th percentile demand (hours)	0.0	6.3	95.3	768.0	1143.5	1678.8	2270.0	2908.0	3506.8	4038.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	2.01	40.24	85.15	163.49	287.17	473.23	728.07	1106.89
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.37	10.47	117.68	200.23	333.35	521.64	805.30	1260.25	1904.92
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.10M	$2.06M	$4.35M	$8.36M	$14.68M	$24.19M	$37.22M	$56.58M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.02M	$0.53M	$6.02M	$10.23M	$17.04M	$26.66M	$41.16M	$64.42M	$97.37M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.01M	$0.23M	$3.24M	$6.12M	$10.96M	$18.27M	$29.28M	$45.38M	$68.82M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	57.7	68.1	94.9	117.2	123.0	122.0	120.3	118.7	117.0	114.5
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 winter rating is at an ambient temperature of 5 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. "N-1 hours at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 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 160 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
- 140 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 95,932 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.

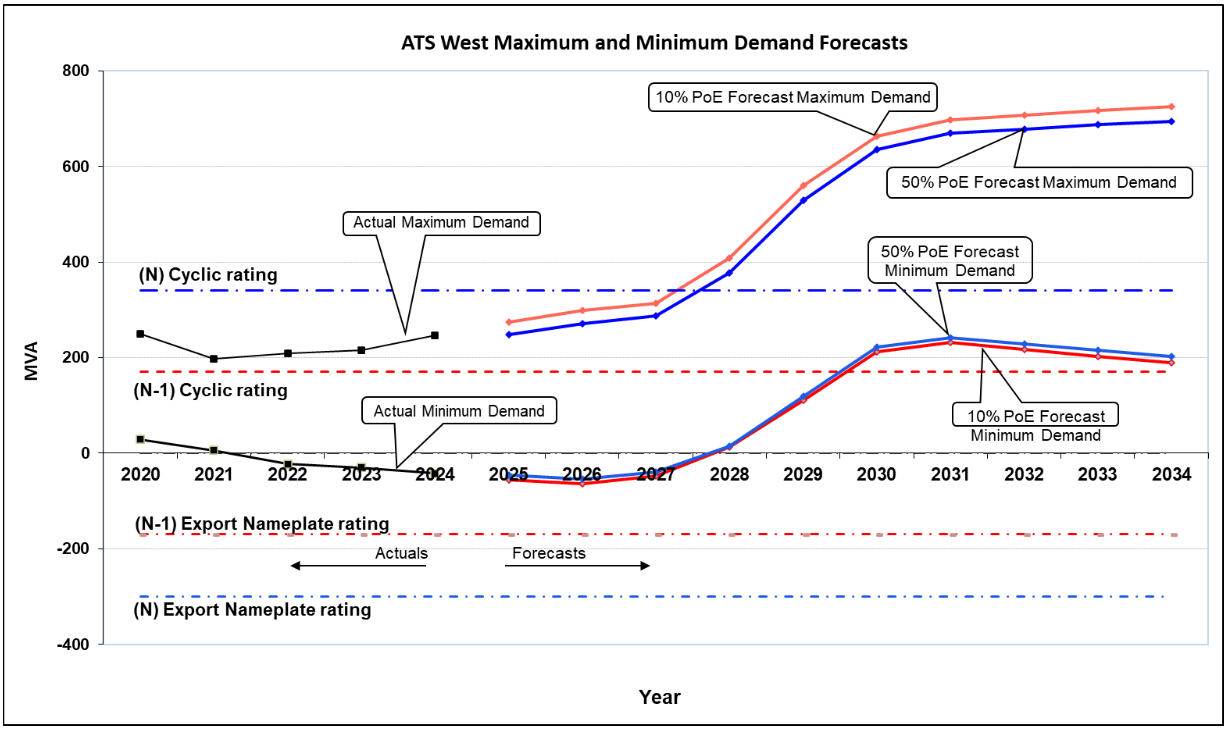
ATS West is a summer peaking station and its maximum demand reached 237.4 MW (246.1 MVA) in summer 2023-24.

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 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 Stations (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 5 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:

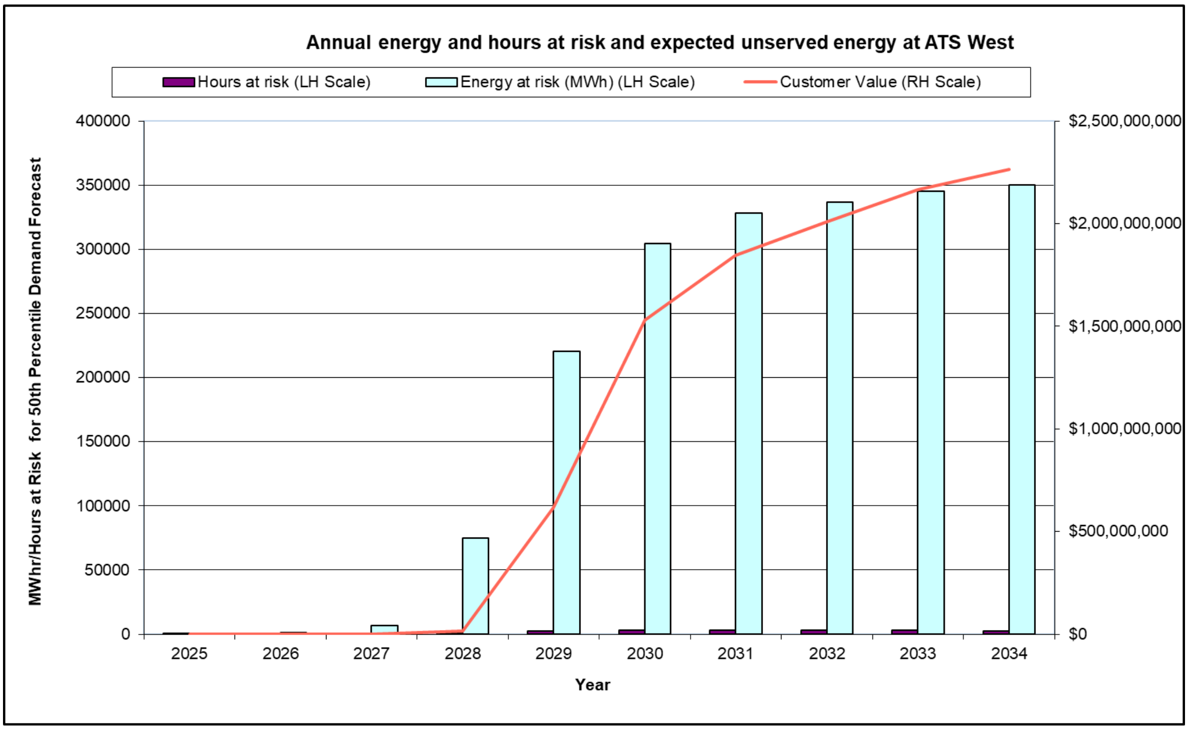
- For 0.5 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.99

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.

The graph above shows that there is insufficient import capacity to supply the forecast maximum demand at 50th percentile temperature at ATS West from 2028 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 $40,420 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	75,204	$3,040 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	362	$14.7 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	85,943	$3,456 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	519	$21 million
70/30 weighted expected unserved energy value (see below)	**409.4**	**$16.6 million**

Under the probabilistic planning approach[48], 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[49]. 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

48 See section 3.

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

to the 50th and 10th percentile expected unserved energy estimates (respectively)[50]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2028 is $16.6 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[51] automatic load shedding scheme which is operated by AusNet Transmission Group's TOC[52] 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 24 MVA in summer 2024.

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 three transformers are supplying the ATS West load, and one transformer will continue to provide capacity to the ATS/BLTS system.

2. A new zone substation in the Mt Cottrell area supplied from DPTS to offload Werribee and Laverton zones substations load in the order of 40 MW. This will not eliminate the load at risk at ATS West, only reduce it.

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

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

Preferred network option(s) for alleviation of constraints

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

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

[51] Overload Shedding Scheme of Connection Asset.

[52] Transmission Operation Centre

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 be economically justified by around 2028. 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	340	via 2 transformers (summer)
Summer N-1 Station Import Rating:	170	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	187	
Summer N-1 Station Export Rating:	150	[See Note 7]
Winter N-1 Station Export Rating:	150	[See Note 7]

Station: ATS West

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	247.7	271.0	287.0	378.0	529.4	635.2	669.1	678.2	688.6	694.5
50th percentile Winter Maximum Demand (MVA)	191.4	220.1	258.2	386.2	526.6	588.9	604.2	612.5	619.8	624.5
10th percentile Summer Maximum Demand (MVA)	275.1	299.1	313.7	408.2	560.0	663.5	698.1	707.8	718.1	724.7
10th percentile Winter Maximum Demand (MVA)	201.1	230.0	265.9	394.7	535.0	597.9	613.0	621.3	629.8	634.6
N-1 energy at risk at 50% percentile demand (MWh)	504.9	1397.4	6821.0	75204.2	220702.2	304293.0	328127.4	336700.3	345218.2	350213.5
N-1 hours at risk at 50th percentile demand (hours)	20.8	76.8	313.3	1389.0	2467.3	2798.3	2791.8	2771.3	2751.3	2734.0
N-1 energy at risk at 10% percentile demand (MWh)	1060.7	2831.8	9602.5	85492.6	237831.4	322084.6	345756.4	354371.5	363183.7	368420.2
N-1 hours at risk at 10th percentile demand (hours)	37.8	142.0	389.3	1581.3	2611.3	2807.5	2771.3	2743.8	2714.0	2699.0
Expected Unserved Energy at 50th percentile demand (MWh)	2.19	6.06	29.56	362.32	15281.07	37896.44	45661.33	49678.06	53561.33	56049.88
Expected Unserved Energy at 10th percentile demand (MWh)	4.60	12.27	41.61	519.25	18090.21	42798.39	51237.68	55594.00	60281.37	63082.77
Expected Unserved Energy value at 50th percentile demand	$0.09M	$0.24M	$1.19M	$14.65M	$617.67M	$1531.79M	$1845.65M	$2008.00M	$2164.97M	$2265.56M
Expected Unserved Energy value at 10th percentile demand	$0.19M	$0.50M	$1.68M	$20.99M	$731.21M	$1729.93M	$2071.04M	$2247.13M	$2436.59M	$2549.83M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.12M	$0.32M	$1.34M	$16.55M	$651.73M	$1591.23M	$1913.27M	$2079.74M	$2246.46M	$2350.84M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	54.9	64.4	47.7	13.6	111.6	212.5	231.3	217.8	203.3	190.2
Maximum generation at risk under N-1 (MVA)	0.0	0.0	0.0	0.0	0.0	42.5	61.3	47.8	33.3	20.2
N-1 energy curtailment (MWh)	0.0	0.0	0.0	0.0	0.0	58.6	116.0	71.1	36.5	14.6
Expected volume of export energy constrained (MWh)	0.0	0.0	0.0	0.0	0.0	0.3	0.5	0.3	0.2	0.1

Notes:

1. “N-1” means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.

3. "N-1 hours at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 88,054 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 341 MW capacity of embedded generation is installed on the Powercor sub-transmission and distribution systems connected to BATS. It consists of:

- 243 MW of large-scale embedded generation; and
- Around 98 MW of rooftop solar PV, including all the small-scale commercial and residential rooftop PV systems that are smaller than 1 MW.

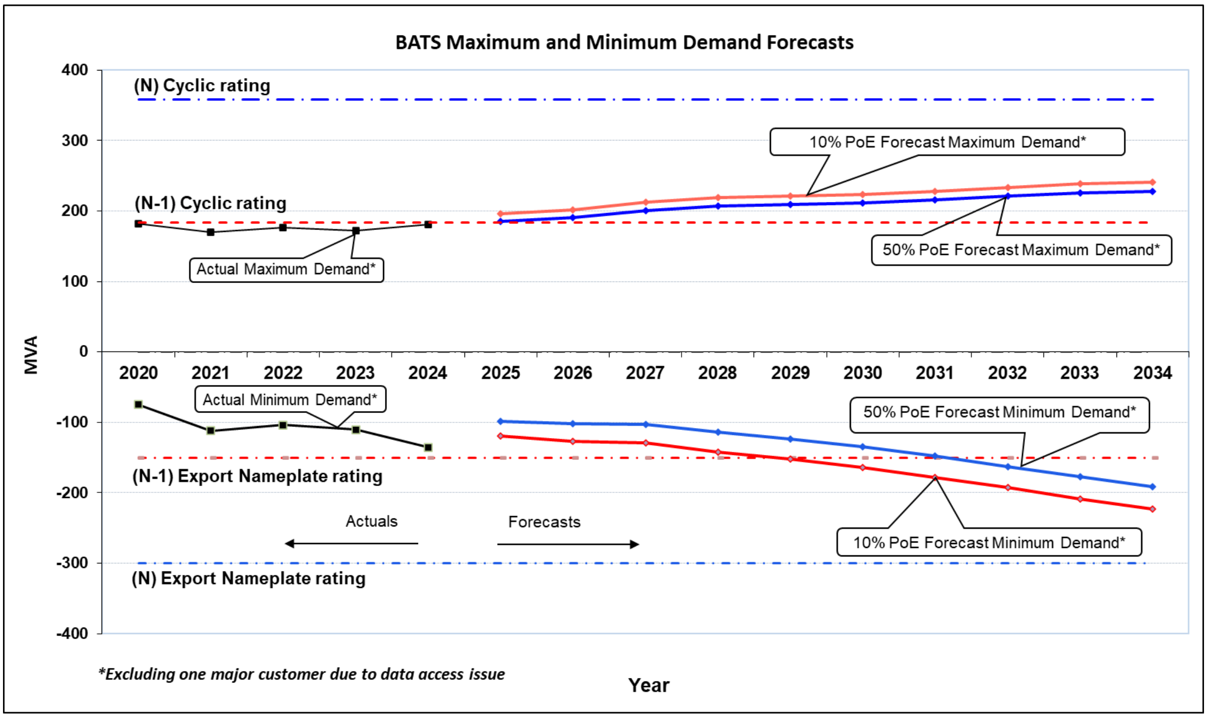
The following table lists the registered embedded generators (>5 MW) that are installed on the Powercor network connected to BATS:

Site name	Status	Technology Type	Nameplate capacity (MW)
Challicum Hills	Existing Plant	Wind Turbine	52.5
Leonard's Hill (LHW)	Existing Plant	Wind Turbine	4.1
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 163.3 MW (166.8 MVA) in summer 2024. It is noted that 2023-24 was a mild summer, and this contributed to reduced station maximum demands. The minimum demand at BATS reached -128.4 MW (-135.24 MVA) in April 2023.

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 35°C ambient temperature. It is noted that at present, there is insufficient data available to enable the impact of all connections 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 5 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.

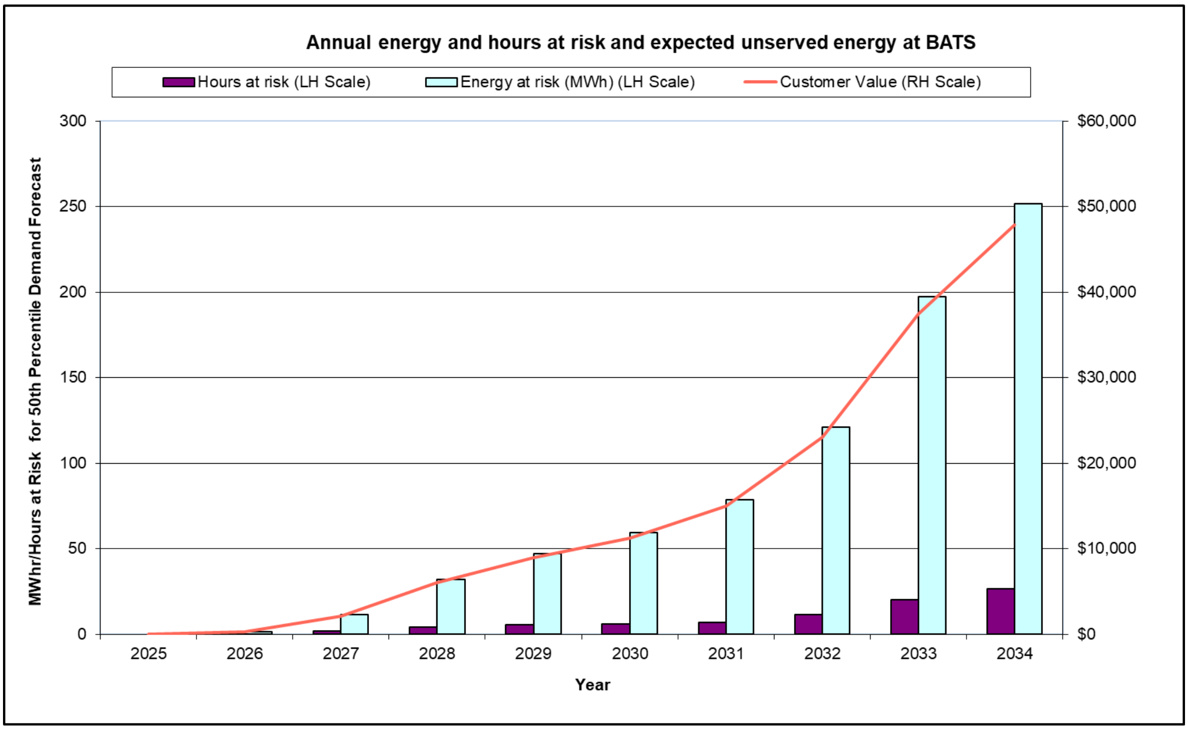
In relation to minimum demand, it is estimated that:

- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of peak minimum demand is 0.95.

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 $43,879 per MWh.



Key statistics relating to energy at risk and expected unserved energy for the year 2034 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	252	$11 million
Expected unserved energy at 50th percentile maximum demand	1.1	$47,880
Energy at risk, at 10th percentile maximum demand forecast	1011	$44 million
Expected unserved energy at 10th percentile maximum demand	4.4	$192,262
70/30 weighted expected unserved energy value (see below)	**2.1**	**$91,140**

Under the probabilistic planning approach[53], 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[54]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

53 See section 3.

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

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)[55]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2033 is $0.09 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 2034, 111 MVA of embedded generation is at risk of curtailment for the loss of one transformer at BATS. This equates to 3,974 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 17 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 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.

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

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

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	358	via 2 transformers (summer)
Summer N-1 Station Import Rating:	183	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	206	
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 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. “Expected unserved energy” means “N-1 energy at risk” for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 30,590 customers in Bendigo and the surrounding area. The station supply area includes Marong, Newbridge and Lockwood.

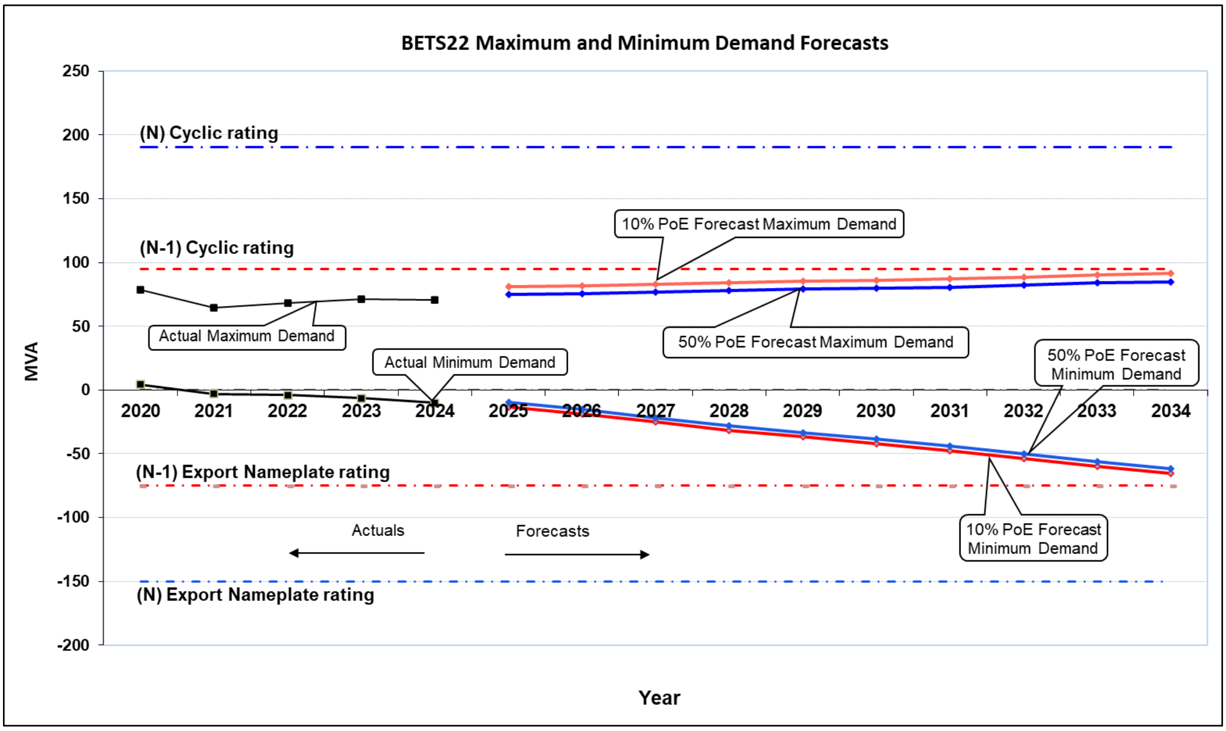
Embedded generation

About 47 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 -1.1 MVA (-1.1%) per annum over the last 5 years. The maximum demand for the 22 kV network now on the station reached 70.4 MVA in summer 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 cyclic ratings at 35°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 8 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 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 0.96

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 2034, 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 62,294 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 217 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
- 95 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

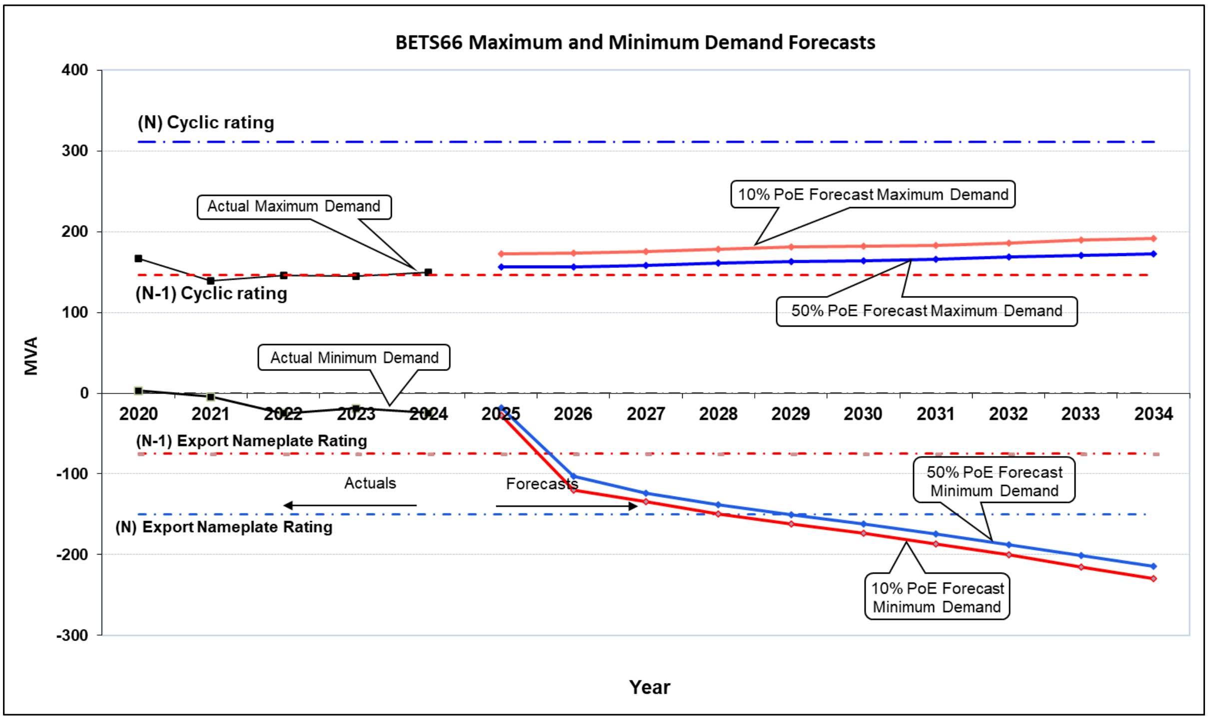
Magnitude, probability and impact of constraints

Growth in summer maximum demand at BETS 66 kV has averaged around -4.7 MVA (-2.6%) per annum over the last 5 years. The peak demand on the station reached 148.3 MW (149.7 MVA) in summer 2024.

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 35°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 8 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

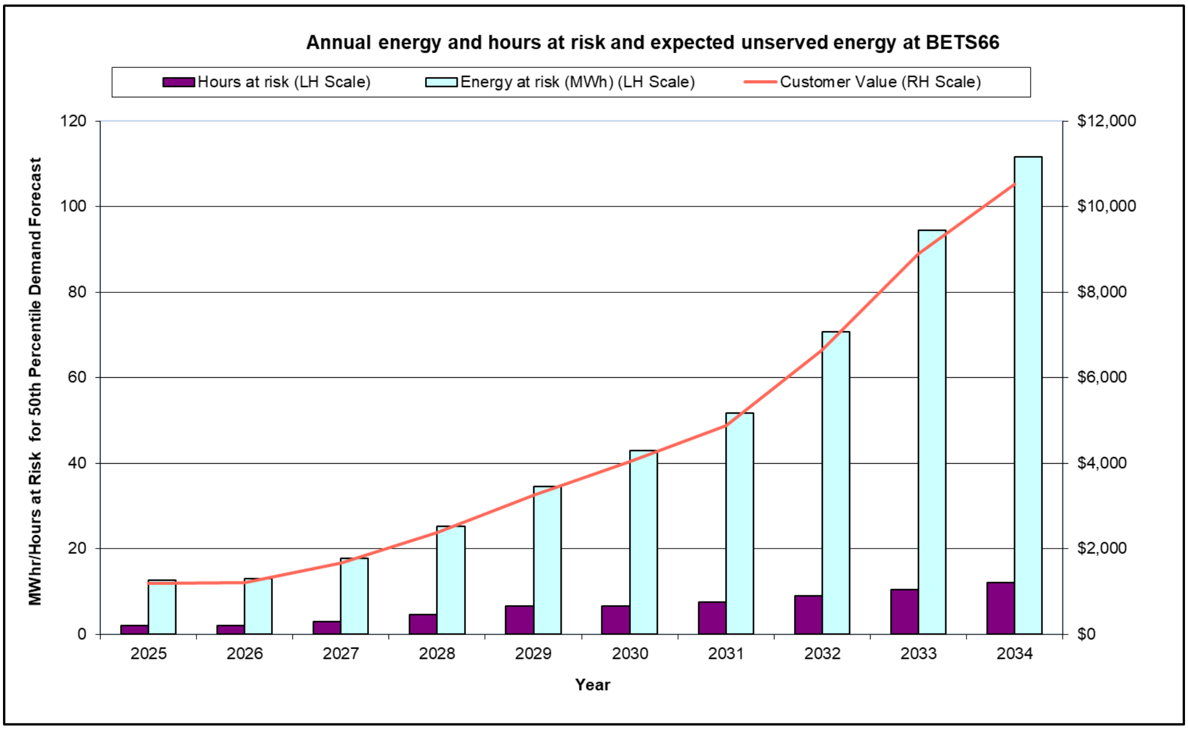
In relation to minimum demand, it is estimated that:

- For 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 0.94

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 $43,461 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2034 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	111.7	$4.9 million
Expected unserved energy at 50th percentile maximum demand	0.2	$10,518
Energy at risk, at 10th percentile maximum demand forecast	463.9	$20.2 million
Expected unserved energy at 10th percentile maximum demand	0.9	$43,684
70/30 weighted expected unserved energy value (see below)	**0.47**	**$20,467**

Under the probabilistic planning approach[56], 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[57]. 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)[58].

56 See section 3.

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

58 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 2034 is $0.02 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 2028, 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 period in 2034, 155 MVA of embedded generation is at risk of curtailment for the loss of one transformer at BETS. This equates to 762 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 97 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[59] automatic load shedding scheme which is operated by AusNet Transmission Group's TOC[60] 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 19 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.

[59] Overload Shedding Scheme of Connection Asset.

[60] Transmission Operation Centre.

Preferred option(s) for alleviation of constraints

As already noted, a contingency plan to transfer 19 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.

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 310.9 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Import Rating: 146.7 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 173.7 MVA
Summer N-1 Station Export Rating: 75 MVA [See Note 7]
Winter N-1 Station Export Rating: 75 MVA [See Note 7]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	156.3	156.4	158.5	160.8	162.9	164.3	165.7	168.3	171.1	172.8
50th percentile Winter Maximum Demand (MVA)	138.6	137.0	138.9	141.4	142.7	143.6	145.4	148.3	150.8	151.7
10th percentile Summer Maximum Demand (MVA)	172.8	173.2	175.4	178.6	180.9	181.9	183.5	186.3	189.7	191.5
10th percentile Winter Maximum Demand (MVA)	147.3	144.8	146.8	149.2	150.5	151.4	153.5	156.3	158.6	159.3
N-1 energy at risk at 50% percentile demand (MWh)	12.6	12.9	17.7	25.2	34.6	42.9	51.8	70.7	94.5	111.7
N-1 hours at risk at 50th percentile demand (hours)	2.0	2.0	3.0	4.5	6.5	6.5	7.5	9.0	10.5	12.0
N-1 energy at risk at 10% percentile demand (MWh)	111.5	115.4	141.6	184.1	221.0	238.4	269.1	328.1	413.3	463.9
N-1 hours at risk at 10th percentile demand (hours)	12.0	12.0	13.5	17.5	20.0	22.0	24.0	27.0	32.0	34.5
Expected Unserved Energy at 50th percentile demand (MWh)	0.03	0.03	0.04	0.05	0.07	0.09	0.11	0.15	0.20	0.24
Expected Unserved Energy at 10th percentile demand (MWh)	0.24	0.25	0.31	0.40	0.48	0.52	0.58	0.71	0.90	1.01
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M	$0.01M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.01M	$0.01M	$0.02M	$0.02M	$0.02M	$0.03M	$0.03M	$0.04M	$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	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.02M	$0.02M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	27.5	119.6	134.8	149.8	162.0	173.9	186.9	200.5	215.6	229.5
Maximum generation at risk under N-1 (MVA)	0.0	44.6	59.8	74.8	87.0	98.9	111.9	125.5	140.6	154.5
N-1 energy curtailment (MWh)	0.0	24.9	114.0	198.7	230.8	204.2	120.9	251.5	464.7	761.8
Expected volume of export energy constrained (MWh)	0.0	0.1	0.2	0.4	3.0	13.2	11.4	38.2	83.1	97.3

Notes:

1. “N-1” means cyclic station transformer output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours per year at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.
4. “Expected unserved energy” means “ energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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.

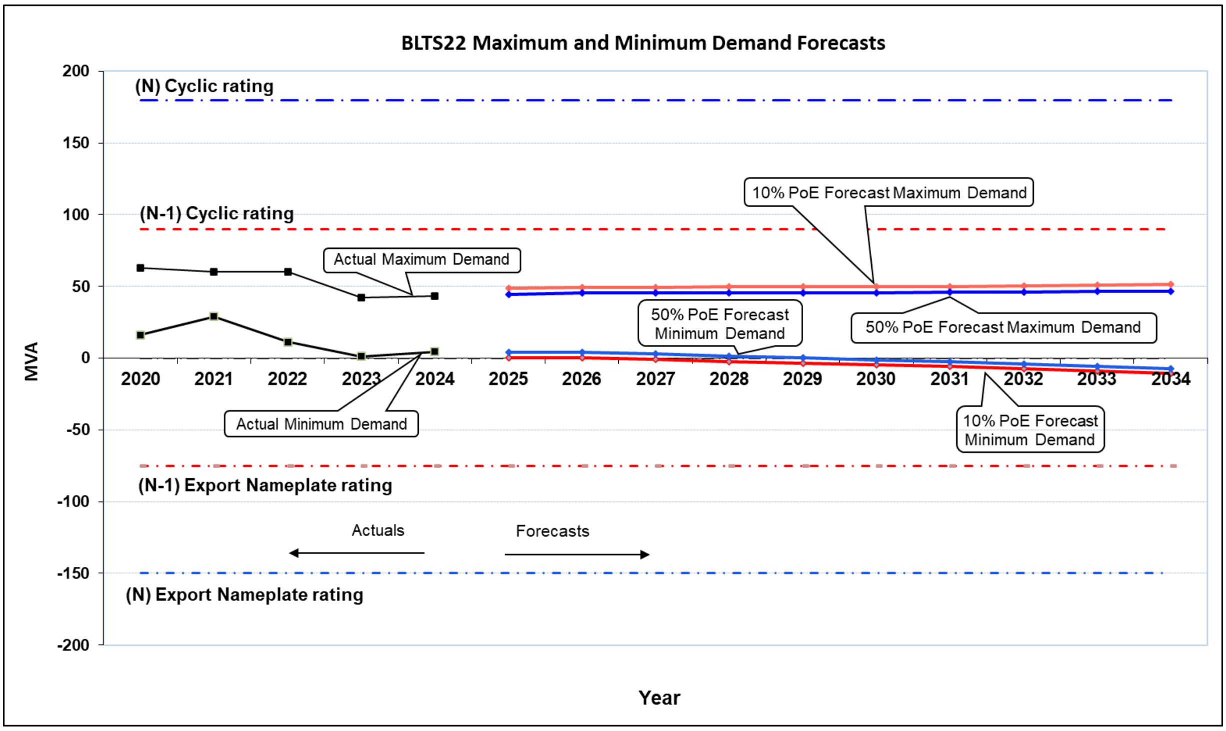
Embedded generation

About 9 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 8,973 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 41.6 MW (43.3 MVA) in summer 2024.

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 35°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 16 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 0.96

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 0.81

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 (43%). It consists of three 75 MVA transformers operating in parallel, and operates at 220/22 kV to supply a total of approximately 41,271 customers in the Brunswick, Fitzroy, Northcote, Fairfield, Essendon, Ascot Vale and Moonee Ponds areas.

Embedded Generation

About 21 MW of solar PV is installed on BTS 22 kV which includes 9 MW in the Powercor distribution system and 12 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

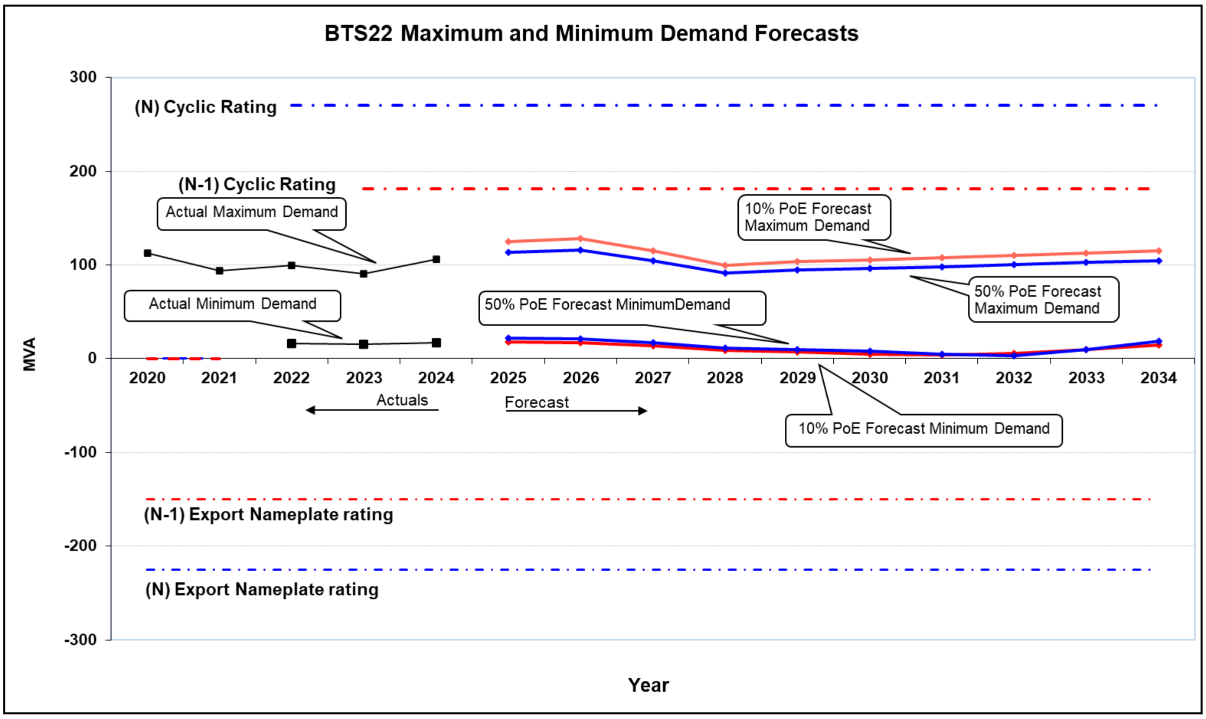
Maximum demand at BTS 22 kV occurs in winter and minimum demand at BTS 22kV occurs in summer.

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 35°C ambient temperature;
- actual station maximum demand reached 103.7 MW (105.8 MVA) in February 2024; and
- actual minimum demand reached 16.9 MW (16.9 MVA) in December 2023.

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 8 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 0.99.

In relation to minimum demand, it is estimated that:

- For 30 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.

Brunswick Terminal Station 22kV

Detailed Import and Export Limitation data

Distribution Businesses supplied by this station: JEN (58%), CitiPower (43%)

Station operational rating (N elements in service): 270 MVA

Summer N-1 Station Import Rating: 181 MVA

N-1 Station Export Rating: 150 MVA

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	113.4	115.9	104.5	91.2	94.5	96.4	98.3	100.7	102.9	104.8
50th percentile Winter Maximum Demand (MVA)	110.4	96.3	101.9	89.3	93.6	96.0	98.5	101.3	104.1	106.2
10th percentile Summer Maximum Demand (MVA)	125.1	128.1	114.8	99.8	103.4	105.5	107.7	110.1	112.8	115.4
10th percentile Winter Maximum Demand (MVA)	119.2	104.0	110.0	96.5	101.1	103.7	106.4	109.2	112.2	114.6
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	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	21.6	21.2	17.0	11.4	9.6	7.9	4.9	3.4	9.6	18.9
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 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 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 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 2019 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 84,857 customers.

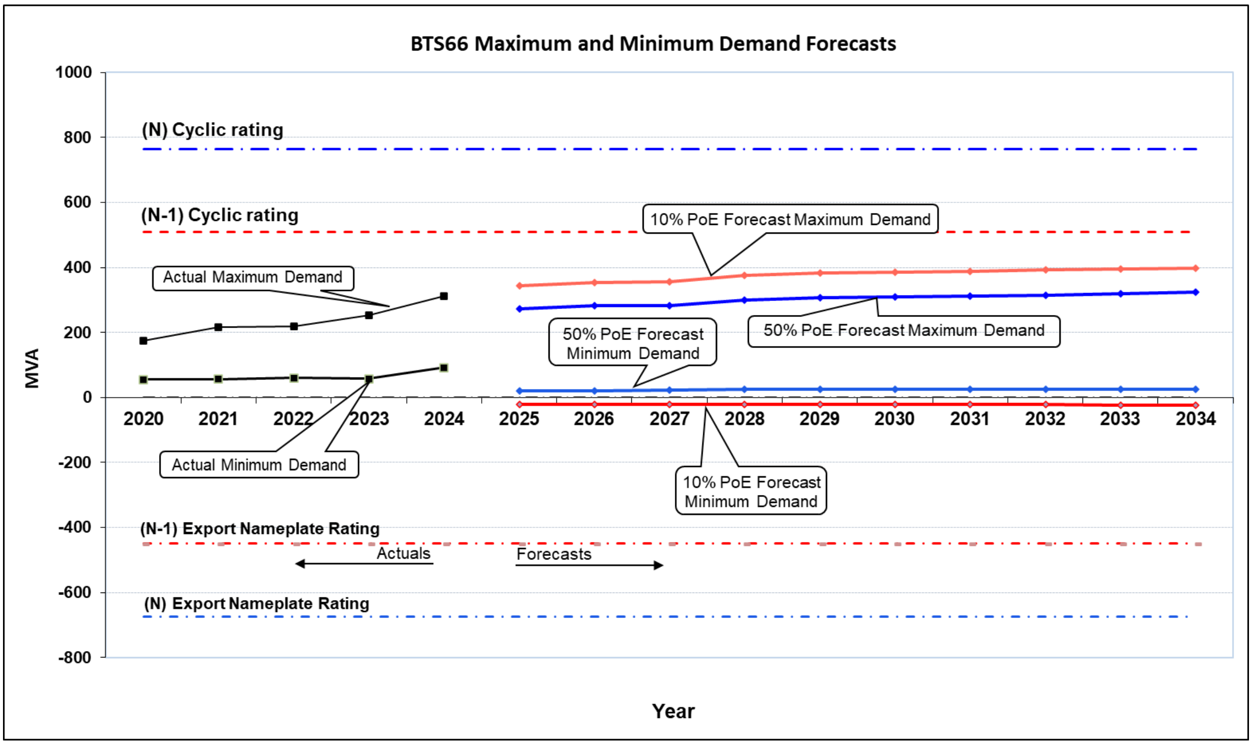
Embedded generation

About 29 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 35 deg 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 304.7 MW (312.64 MVA) in summer 2024.

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 39 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.

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.

In late-2020, AusNet Transmission Group reviewed and updated the cyclic ratings of the CBTS transformers. This review resulted in an increased “N” summer cyclic rating of 553 MVA, up from 538 MVA, and an increased “N-1” summer cyclic rating of 369 MVA, up from 356 MVA. This increased cyclic rating is a result of a changing transformer load profile driven by increased distributed energy resources (DER) reducing station loading during the day.

The geographic area supplied by CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west. The electricity distribution networks for this area are the responsibility of both AusNet Electricity Services (63%) and United Energy (37%).

Embedded generation

A total of 380.2 MW of embedded generation capacity is installed on the distribution systems connected to CBTS, including:

- about 244.8 MW of rooftop solar PV installed on the AusNet distribution system and about 105.2 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

- 30.2 MW capacity of large-scale embedded generation installed on the UE distribution system connected to CBTS.

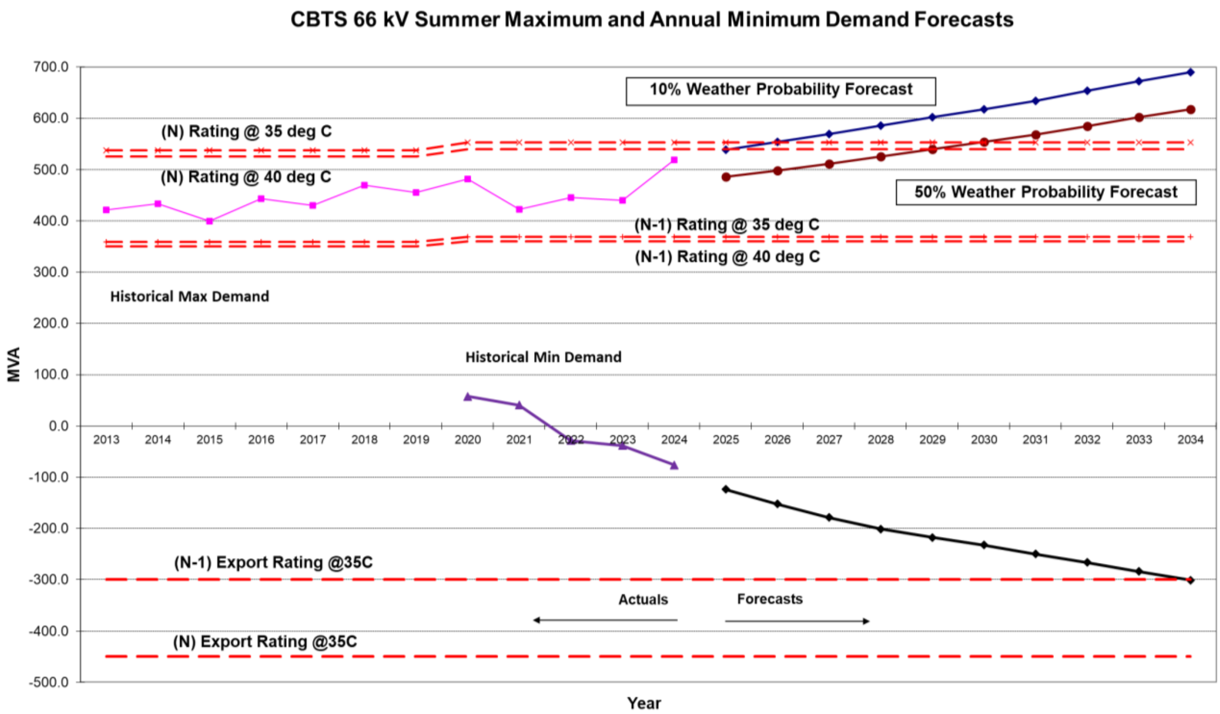
Magnitude, probability and impact of constraints

Maximum demand at CBTS 66 kV occurs in summer. The summer peak demand at CBTS 66 kV has increased by 172 MVA between 2007/08 and 2019/20, which was equivalent to an average annual growth rate of 4.1%. In 2019/20 the summer maximum demand on the station reached 470.6 MW (481.9 MVA). The maximum demand in summer 2023/24 was 503.2 MW (519.4 MVA), which is the highest annual maximum demand recorded to date.

The graph below shows the 10th and 50th percentile summer 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 35°C as well as 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.



The station load has a power factor of 0.97 at maximum demand. 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:

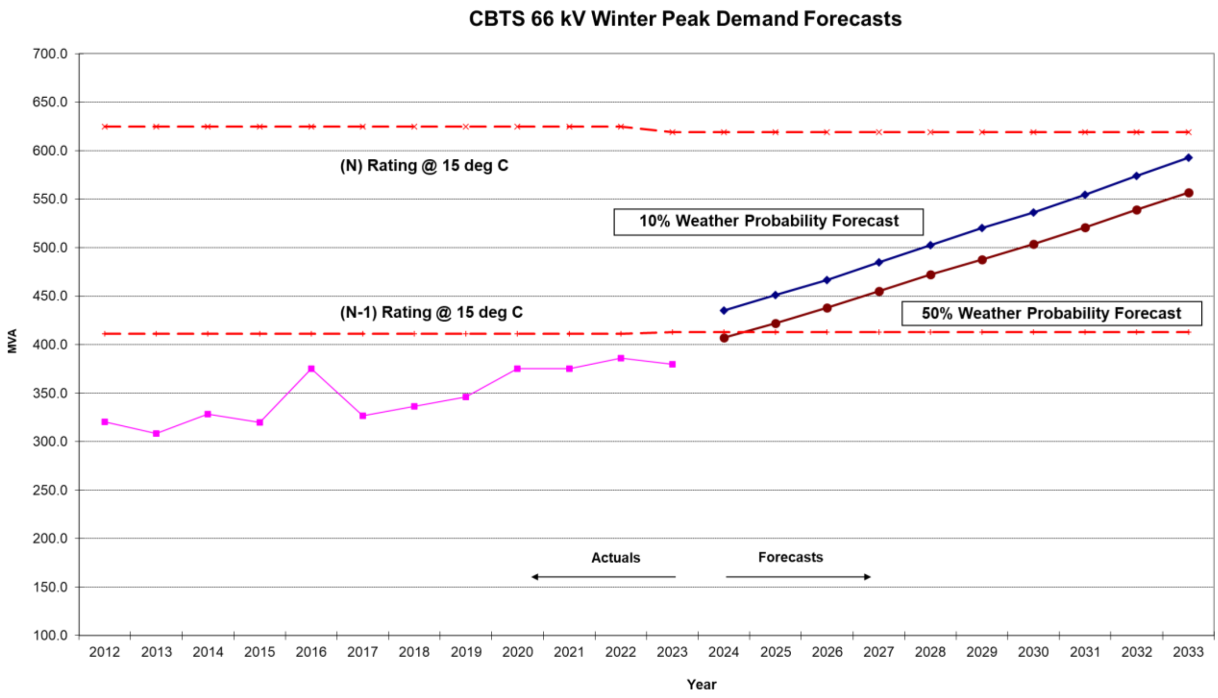
- For 27.5 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.95 at the time of minimum demand.

The "N" import rating on the chart indicates the maximum demand that can be served from CBTS 66 kV with all transformers in service. Exceeding this level would require load shedding or emergency load transfers to keep the terminal station operating within its limits.

Maximum demand at CBTS 66 kV is forecast to be above the station's "N" import rating under 10th percentile summer maximum demand conditions from summer 2025/26 but remain within its 50th percentile "N" rating until summer 2029/2030.

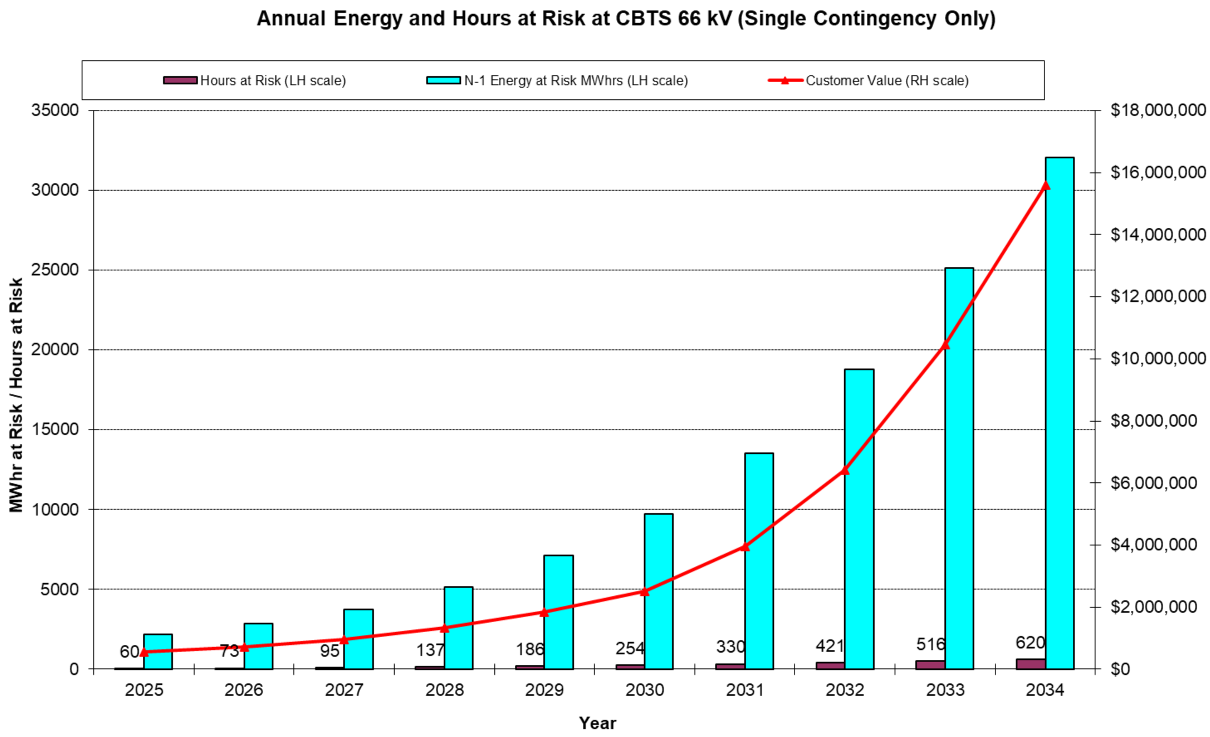
Minimum demand levels remained well within the station's operational "N" and "N-1" export ratings. This trend is expected to continue under 50th percentile minimum demand forecasts over the 10-year planning period, however the station's operational "N-1" export rating is forecast to be exceeded from summer 2033/34 under 10th percentile minimum demand forecasts.

The winter ratings of transformers are higher than the summer ratings due to lower ambient temperatures. The maximum demand at CBTS in winter is also much lower than in summer. Thus, energy at risk during the winter period is much lower than the summer period. The graph below shows the 10th and the 50th percentile winter maximum and minimum demand forecasts together with the station's operational "N" import and export ratings and "N-1" import and export ratings for winter.



Under both 50th and 10th percentile winter maximum demand conditions, the station is expected to exceed its "N-1" ratings from 2024/25 and 2023/24 respectively. The winter maximum demand is not expected to exceed the station's "N" rating during the ten-year planning horizon.

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 cost to consumers of the expected unserved energy in each year, for the 50th percentile maximum demand forecast.



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 $39,600 per MWh.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	3,759	$149 million
Expected unserved energy at 50th percentile maximum demand	25	$0.99 million
Energy at risk, at 10th percentile maximum demand forecast	12,518	$496 million
Expected unserved energy at 10th percentile maximum demand	278	$11.0 million
70/30 weighted expected unserved energy value (see below)	**101**	**$3.99 million**

Under the probabilistic planning approach[61], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[62]. 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)[63]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2026/27 is $3.99 million.

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

Possible impacts of a transformer outage on customers

If one of the 220/66 kV transformers at CBTS is taken 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)[64] which is operated by AusNet Transmission Group's TOC[65] 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, affecting up to 124,000 customers in 2026/27. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy's and AusNet Electricity Services' operational procedures after the operation of the OSSCA scheme.

61 See section 3.1.

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

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

64 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.

65 Transmission Operations Centre

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 70 MVA. Where required, such as if a 10th 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 260 MVA of load.

2. Establish a new 220/66 kV terminal station: AusNet Electricity Services expects that a new terminal station in the Pakenham area (with a site yet to be acquired) will be required in around 10 to 20 years to service demand growth in the region. This development will help to off-load CBTS as well as 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 4th 220/66 kV transformer at Cranbourne Terminal Station: The site has provision for a 4th transformer and implementing this option is relatively straight forward, 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[66]. Due to a material change in one of the inputs (option costs), AusNet and United Energy have re-commenced the RIT-T

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

with the Project Specifications Consultation Report (PSCR)[67] being published in October 2024. The report indicates that the installation of a fourth 220/66 kV transformer at CBTS is likely to be the preferred network option. The estimated annualised cost of this option is approximately $3.5 million and the optimal timing for the project is 2026/27.

Prior to implementing any augmentation option, 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 and 66 kV tie lines; 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.

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

CRANBOURNE TERMINAL STATION
Detailed data: System normal maximum and minimum demand forecasts and limitations

Distribution Businesses supplied by this station: United Energy (37%) and AusNet Electricity Services (63%)

Normal import cyclic rating with all plant in service	553	MVA via 3 transformers (Summer peaking)
Summer Import N-1 Station Rating	369	MVA [See Note 1 below for interpretation of N-1]
Winter Import N-1 Station Rating	413	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	300	MVA [See Note 7 below for interpretation of Export rating]

Import	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
50th percentile Summer Maximum Demand (MVA)	485.9	498.1	510.8	525.4	539.9	553.7	568.6	585.1	602.2	617.1
50th percentile Winter Maximum Demand (MVA)	422.3	438.0	455.5	472.1	488.0	503.5	520.7	539.1	556.7	573.1
10th percentile Summer Maximum Demand (MVA)	539.0	553.8	569.2	586.1	602.2	617.7	634.6	653.2	672.2	689.4
10th percentile Winter Maximum Demand (MVA)	450.9	466.8	484.8	502.4	520.1	536.4	554.7	574.0	593.0	609.8
N - 1 energy at risk at 50th percentile demand (MWh)	2,191	2,850	3,759	5,167	7,135	9,749	13,521	18,792	25,112	32,041
N - 1 hours at risk at 50th percentile demand (hours)	60	73	95	137	186	254	329	418	511	612
N - 1 energy at risk at 10th percentile demand (MWh)	7,469	9,463	12,518	16,756	22,130	28,383	36,788	47,669	60,323	73,454
N - 1 hours at risk at 10th percentile demand (hours)	137	185	254	341	432	540	659	804	959	1,127
N energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	12	40	101	186
N energy at risk at 10th percentile demand (MWh)	0	46	195	451	791	1,176	1,645	2,224	2,874	3,529
N and N-1 Expected Unserved Energy at 50th percentile demand (MWh)	15	19	25	34	47	65	102	165	267	398
N and N-1 Expected Unserved Energy at 10th percentile demand (MWh)	49	109	278	562	937	1,364	1,889	2,540	3,273	4,016
N and N-1 Expected Unserved Energy value at 50th percentile demand	$0.57M	$0.75M	$0.99M	$1.36M	$1.87M	$2.56M	$4.02M	$6.52M	$10.58M	$15.77M
N and N-1 Expected Unserved Energy value at 10th percentile demand	$1.96M	$4.32M	$11.01M	$22.27M	$37.12M	$54.00M	$74.81M	$100.58M	$129.62M	$159.03M
N and N-1 Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.99M	$1.82M	$3.99M	$7.63M	$12.45M	$17.99M	$25.26M	$34.74M	$46.29M	$58.75M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	-123.9	-152.4	-178.5	-200.9	-217.3	-232.4	-249.6	-266.4	-284.0	-300.7
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	0.7
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 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 2019 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 109,058 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 176.8 MW of embedded generation is installed on the Powercor distribution system connected to DPTS. This consists of:

- 8.8 MW of large-scale embedded generation; and
- Around 168 MW of rooftop solar PV, including all the small-commercial and residential rooftop PV systems that are smaller than 1 MW.

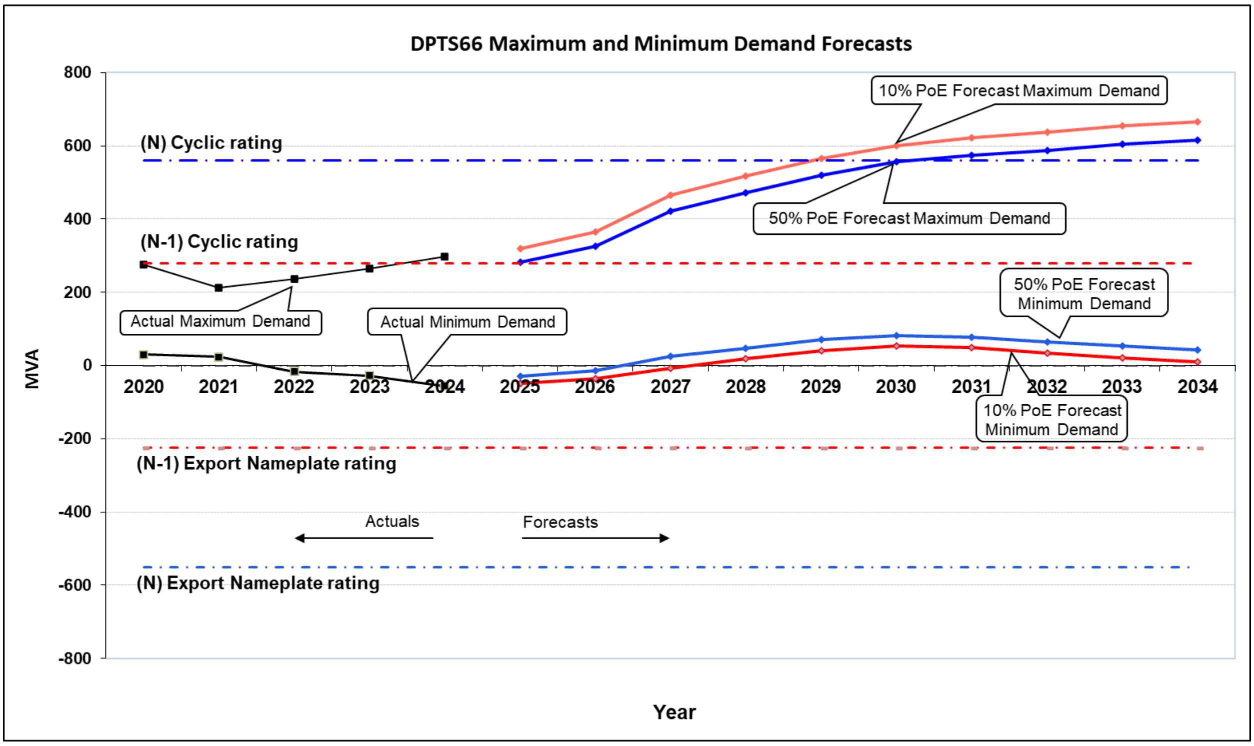
Magnitude, probability and impact of constraints

The maximum demand on the station reached 291.7MW (298.62 MVA) in summer 2024. Maximum demand at the 10th percentile temperature is forecast to increase to 667 MVA by 2034, 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 35 deg 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 8 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 0.98

In relation to minimum demand, it is estimated that:

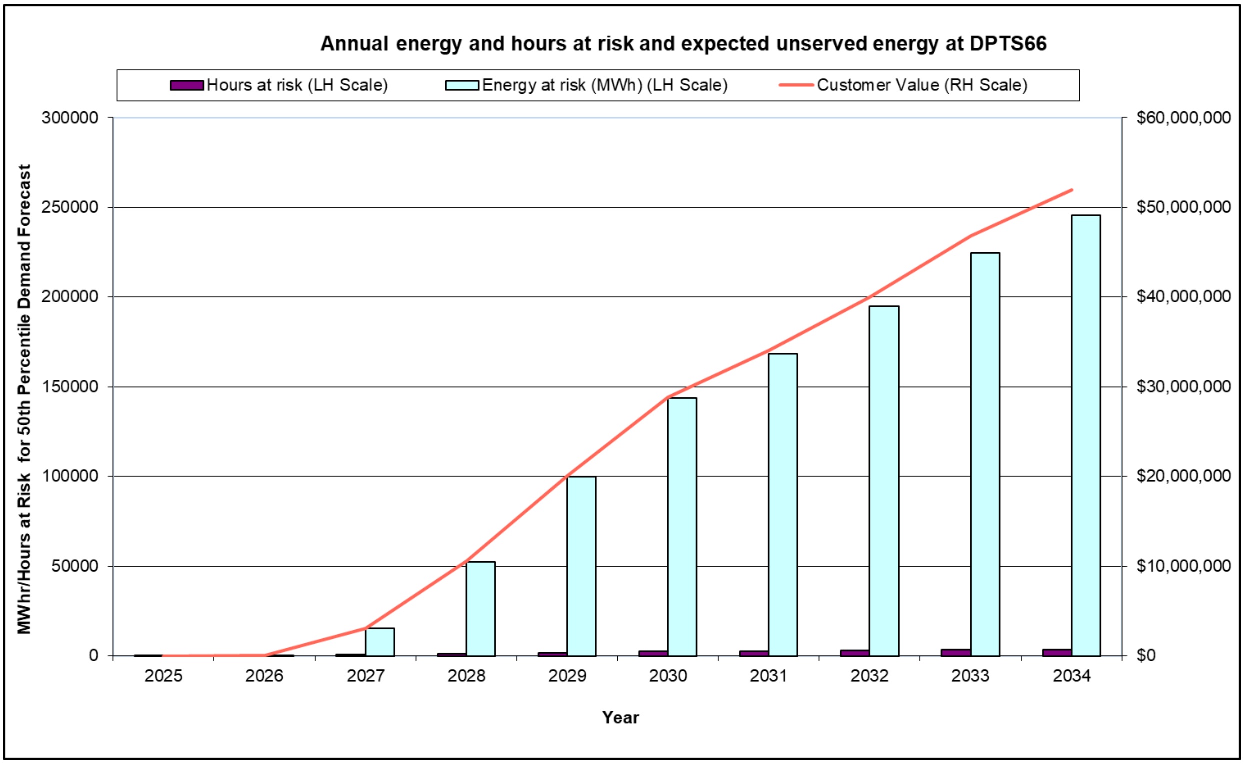
- For 3 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.97

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.

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. It also shows that from 2029, at the 10th percentile temperature, and from 2030, at the 50th percentile temperature, there is a risk of insufficient capacity at the station 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 $46,304 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. The procurement of a replacement would take 12 months, so in the case of DPTS, a major outage of a transformer is assumed to have a duration of 12 months.



Key statistics relating to energy at risk and expected unserved energy for 2027 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	15,236	$705 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	66	$3.1 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	33,905	$1,570 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	146.9	$6.8 million
70/30 weighted expected unserved energy value (see below)	**90.3**	**$4.2 million**

Under the probabilistic planning approach[68], 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[69]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

68 See section 3.

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

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)[70]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2027 is $4.2 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 27 MVA in summer 2024.

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 three transformers are supplying the DPTS load. Given the forecasts of expected unserved energy, the installation of an additional transformer would be economically justified by 2027.

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 possibly act as a substitute for capacity augmentations.

Powercor will commence the pre-feasibility studies to assess options to address this limitation, including a RIT-T if necessary prior to the next TCPR.

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.

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

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	560	via 2 transformers (summer)
Summer N-1 Station Import Rating:	280	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	300	
Summer N-1 Station Export Rating:	225	[See Note 7]
Winter N-1 Station Export Rating:	225	[See Note 7]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	282.4	326.8	420.6	472.1	520.2	555.7	573.8	588.2	604.3	615.5
50th percentile Winter Maximum Demand (MVA)	254.2	326.2	392.0	443.9	484.4	511.8	525.0	539.0	553.1	562.6
10th percentile Summer Maximum Demand (MVA)	319.3	364.8	464.4	516.9	565.8	601.4	621.2	636.6	654.4	666.7
10th percentile Winter Maximum Demand (MVA)	277.6	349.3	420.8	474.4	516.2	545.4	560.0	575.3	592.0	602.3
N-1 energy at risk at 50% percentile demand (MWh)	1.2	275.3	15236.0	52464.5	99977.5	143475.7	168286.6	194935.2	224493.5	245668.9
N-1 hours at risk at 50th percentile demand (hours)	0.5	27.0	555.0	1233.0	1848.5	2392.0	2695.8	2972.8	3261.3	3459.3
N-1 energy at risk at 10% percentile demand (MWh)	64.5	2153.0	33904.8	88226.9	153028.5	210924.8	244710.5	279448.3	320538.8	348096.4
N-1 hours at risk at 10th percentile demand (hours)	5.0	141.0	942.0	1716.0	2530.8	3150.8	3476.8	3779.8	4139.8	4375.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.01	1.19	66.02	227.35	433.24	621.73	735.95	864.18	1011.70	1121.57
Expected Unserved Energy at 10th percentile demand (MWh)	0.28	9.33	146.92	382.32	665.95	948.78	1130.05	1329.77	1594.06	1789.40
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.06M	$3.06M	$10.53M	$20.06M	$28.79M	$34.08M	$40.01M	$46.85M	$51.93M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.43M	$6.80M	$17.70M	$30.84M	$43.93M	$52.33M	$61.57M	$73.81M	$82.86M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.17M	$4.18M	$12.68M	$23.29M	$33.33M	$39.55M	$46.48M	$54.94M	$61.21M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	49.7	35.2	8.3	18.1	40.1	52.5	48.5	33.7	20.9	10.8
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 station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. "N-1 hours at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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.

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

- 235.7 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.

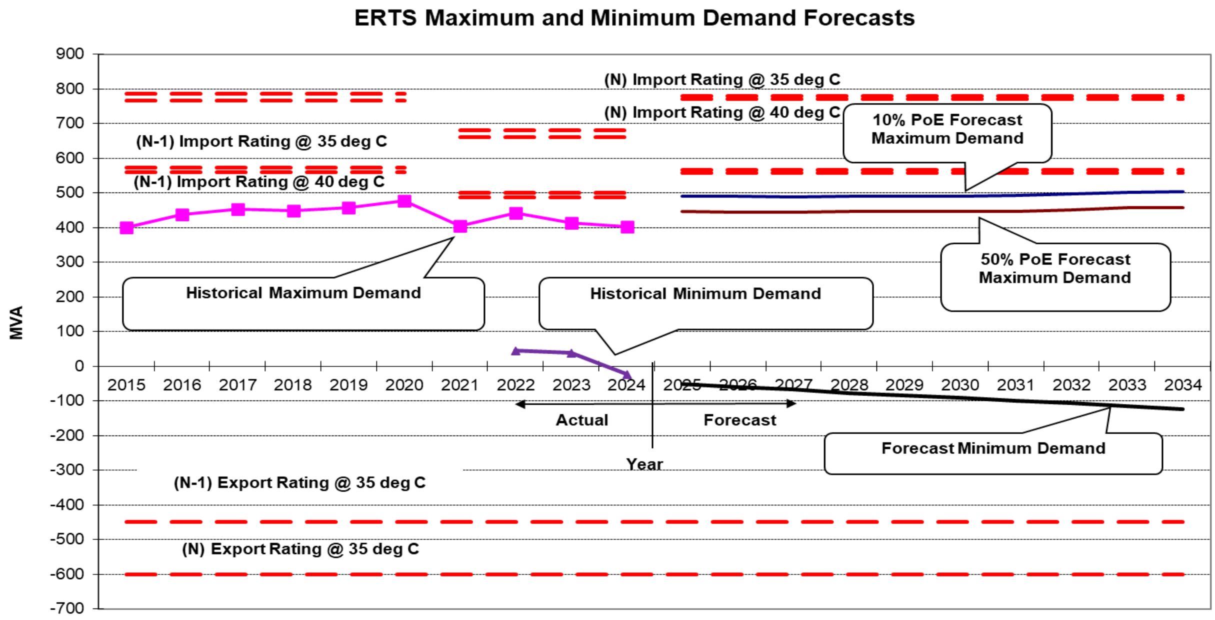
Magnitude, probability, and impact of constraints

The recorded maximum demand in summer 2024 was 394 MW (402 MVA). This was 9.4 MW lower than the maximum demand recorded in summer 2023. The recorded maximum demand in winter 2023 was 428.8 MW (412.9 MVA). This was 19.1 MW higher than the maximum demand recorded in winter 2022. Hence ERTS 66 kV is a winter peaking station as of this year, given the relatively mild summer.

In 2019, the ERTS B3 transformer was replaced with a new higher impedance transformer. This resulted in a decline in the station ratings due to an increased load share on the older transformers. However, ERTS B1 and B4 transformers have now been replaced. Therefore, the load share on all transformers is balanced again resulting an increase of the station rating.

The graph below shows 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 35°C as well as 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.



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 8 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 0.66.

The N import rating on the chart indicates the maximum demand that can be supplied from ERTS 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.

Being a four-transformer station, the ERTS 66 kV bus was split into two bus groups (B12 and B34), each containing two transformers during normal operation, in order to reduce the 66 kV fault level. In the event of a transformer outage, the normally open 66 kV bus tie circuit breaker will be automatically closed to share the demand across the other three transformers.

There is approximately 53.8.4 MVA of load transfer available at ERTS for summer 2025.

The above graph indicates that the overall demand at ERTS remains below its N and N-1 import rating within the 10-year planning period. Therefore, the need for augmentation of ERTS to alleviate import constraints is not expected to arise over the next decade.

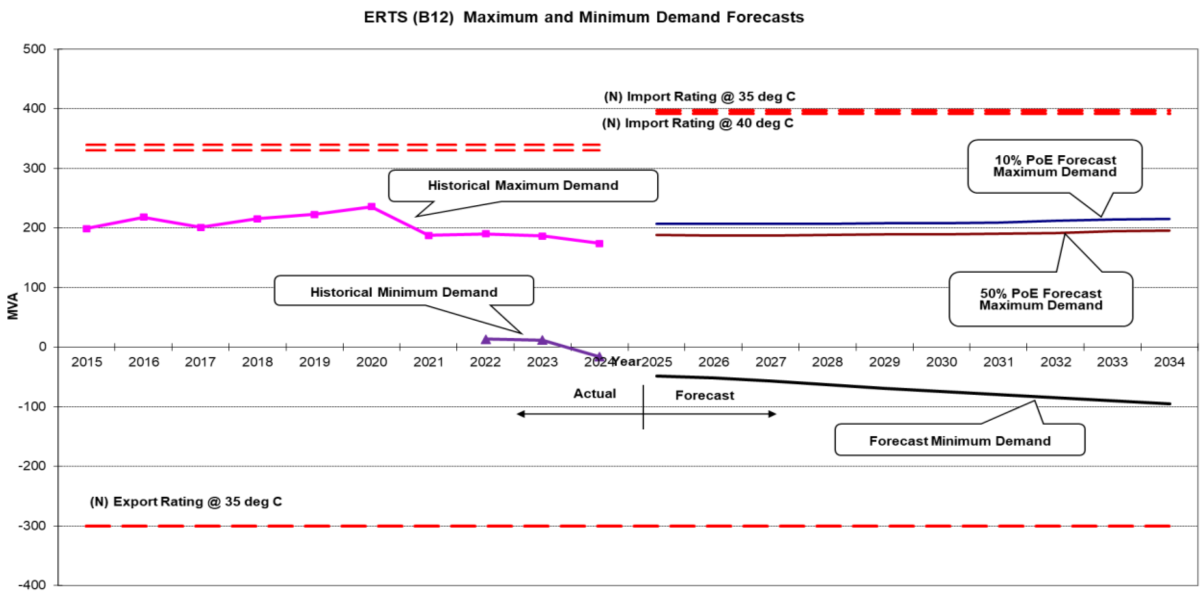
There is expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

The following sections discuss the demand on the two bus groups under normal operating conditions.

Transformer group ERTS (B12): Summer maximum demand forecasts

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

The graph below depicts the ERTS (B12) bus group import ratings with both transformers in service ("N" rating), the historical demand and the 10th and 50th percentile maximum demand forecasts. The recent replacement of B1 Transformer has resulted in increase in the import ratings of the bus group.



Note in the graph above, 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 bus group.

The graph indicates that both the 10th and 50th percentile forecast maximum demands connected to the bus group ERTS (B12) are below its N rating for the entire planning period. Therefore, the maximum demand at ERTS (B12) bus group is not expected to exceed its total import capacity under normal operation at any time over the 10-year planning period.

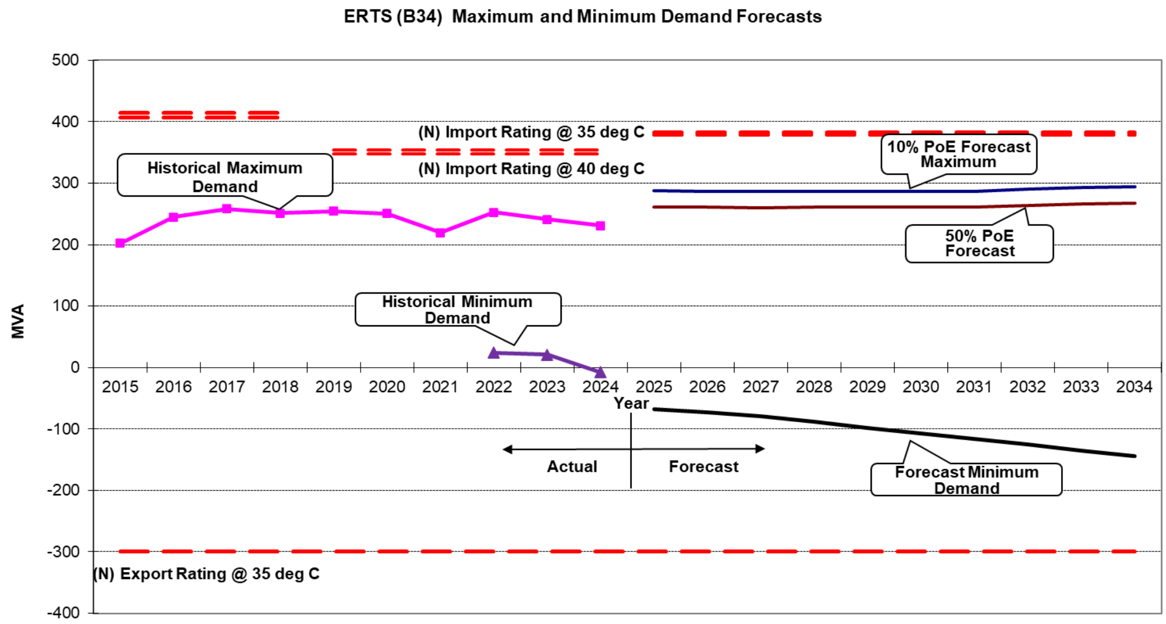
Transformer group ERTS (B34): Summer maximum demand forecasts

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

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

As previously noted, the ERTS B3 transformer was replaced in 2019 resulting in an uneven load share and lower rating on this bus group. With the recent replacement of the ERTS B4 transformer, the import rating of the bus group has been increased.

The graph indicates that the forecast maximum demand supplied from the bus group ERTS (B34) is below its N import rating for the full planning period. Therefore, it is not expected that the connected demand will exceed the total import capacity of the bus group under normal operation at any time over the 10-year planning period.



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 bus group.

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

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 41,755 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.

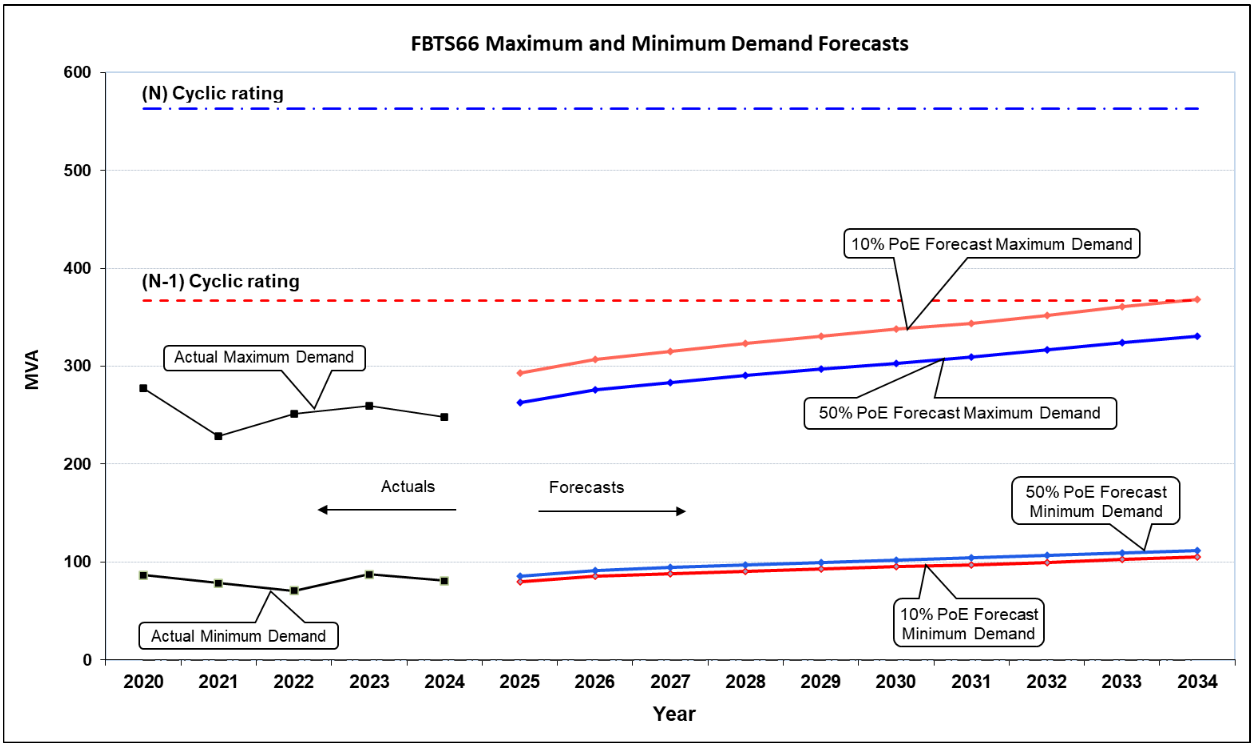
Embedded generation

About 10.6 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 238.8 MW (247.97 MVA) in summer 2024.

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 42 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 36 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 1.0.

The graph shows that under the 10th and 50th percentile maximum demand forecasts, there would be sufficient import capacity at FBTS 66 kV to supply all expected load over the forecast period until 2033, even with one transformer out of service. There will be a small amount of load at risk under 10th percentile forecast conditions from 2034. CitiPower expects that such load at risk will be managed through load transfers or other cost-effective operational measures. The alternative would be to install a 4th transformer for which space exists, however due to the low expected unserved energy and the likely availability of cost-effective alternatives, there are presently no plans to install a fourth transformer at that time. Therefore, the need for augmentation 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.

FRANKSTON TERMINAL STATION (FTS)

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

Embedded generation

About 105 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 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 the purpose of 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 @ 35ºC	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 35 MVA of load transfer available for the loop for summer 2024/25.

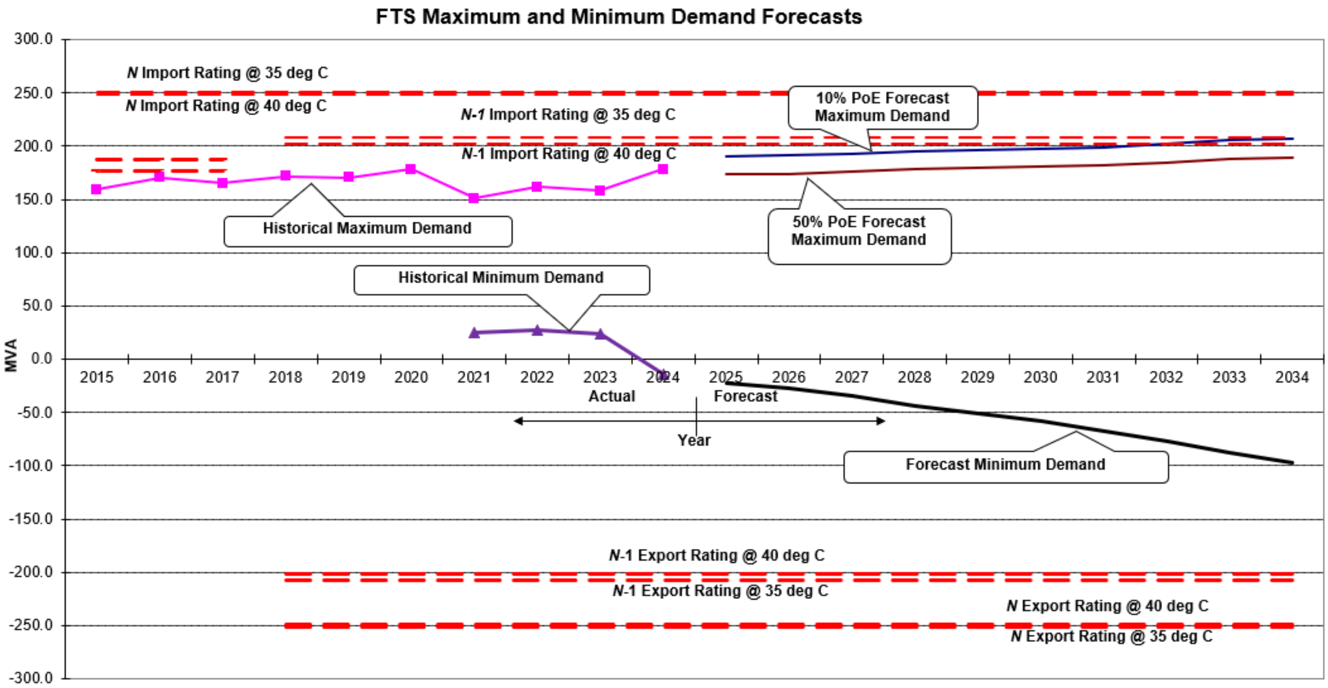
The various 66 kV supply routes and ownership arrangements mean that the risk assessment for FTS is more complicated than for other terminal stations. Whilst there are more limiting constraints within the sub-transmission loop, as far as transmission connection assets are concerned, load flow studies 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 10th and 50th percentile maximum and minimum demand forecasts together with the station's operational (N-1) import and exports ratings at 35°C as well as 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 (N-1) export 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.



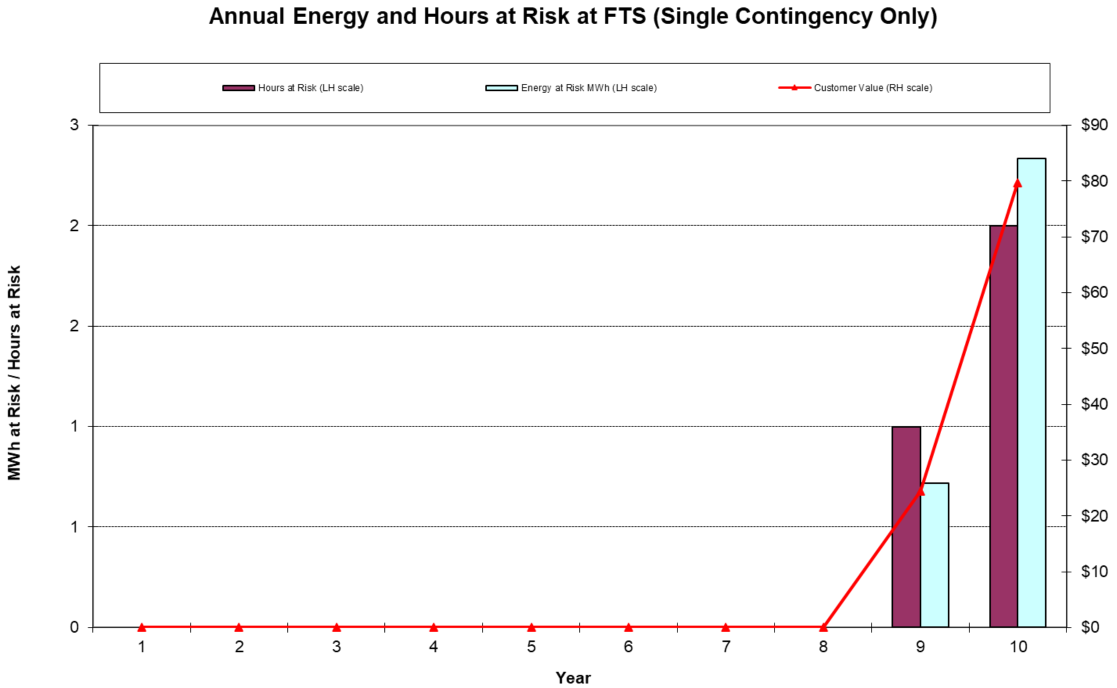
The forecast minimum demand corresponds to a 10% probability of under-reach. Where this forecast falls below 0, this indicates a net export at the Terminal Station.

The graph indicates that overall maximum demand at FTS 66 kV is expected to exceed the (N-1) import rating under 10th percentile maximum demand in 2032. However, the 50th percentile summer maximum demand will remain within the (N-1) import rating for the forecast period.

The station load is forecast to have a power factor of 0.96 at times of peak demand. The demand at FTS is expected to exceed 95% peak demand for approximately 25 hours per annum.

The station load is forecast to have a power factor of 0.76 at times of minimum demand. The demand at FTS is expected to reach 95% minimum demand for approximately 2.5 hours per annum.

The bar chart below depicts the energy at risk with the CBTS-CRM 66kV line 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 $41,210 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2034 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile demand forecast	0	$0
Expected unserved energy at 50th percentile demand	0	$0
Energy at risk, at 10th percentile demand forecast	2	$96,242
Expected unserved energy at 10th percentile demand	0.002	$80
70/30 weighted expected unserved energy value (see below)	**0.001**	**$24**

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)[71]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $24.

On the basis of the current 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.

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

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

FRANKSTON TERMINAL STATION 66kV (UED's share ex CBTS)

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): 251 MVA via all 66kV lines (Summer peaking)
Summer N-1 Loop Import Rating: 208 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Loop Import Rating: 244 MVA
Summer N-1 Loop Export Rating: 208 MVA [See Note 7]
Winter N-1 Loop Export Rating: 244 MVA [See Note 7]

Station: FTS 66kV import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	174	174	176	178	180	181	182	185	188	190
50th percentile Winter Maximum Demand (MVA)	147	149	151	154	155	156	158	161	163	165
10th percentile Summer Maximum Demand (MVA)	190	191	193	195	197	197	199	202	205	207
10th percentile Winter Maximum Demand (MVA)	155	156	158	161	162	163	165	168	171	173
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	1	2
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	0	1	2
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	0.0	0.0	0.0	0.0
Expected Unserved Energy value at 50th percentile demand	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K
Expected Unserved Energy value at 10th percentile demand	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.0K	$0.1K
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile vale + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Hours per year that 95% of 10th percentile demand is expected to be reached	25	25	25	25	25	25	25	25	25	25
Station load power factor at the time of 10th percentile demand	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96

Station: FTS 66kV export	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
10th percentile minimum demand (MVA)	-22.20	-27.17	-34.86	-43.28	-50.74	-58.5	-67.52	-76.88	-87.19	-97.29
Maximum generation at risk under N-1 (MVA)	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
Expected volume of export energy curtailed (MWh)	0	0	0	0	0	0	0	0	0	0

Notes:

1. "N-1" means import rating of FTS during summer during the outage of the CBTS-CRM 66 kV line. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one 66kV line. "Major outage" means an outage with duration of 12 hours or 168 hours for overhead or underground sections respectively. 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 2019 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 thermal 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.

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 was 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 191,189 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 382.5 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
- 218 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 generator (>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.

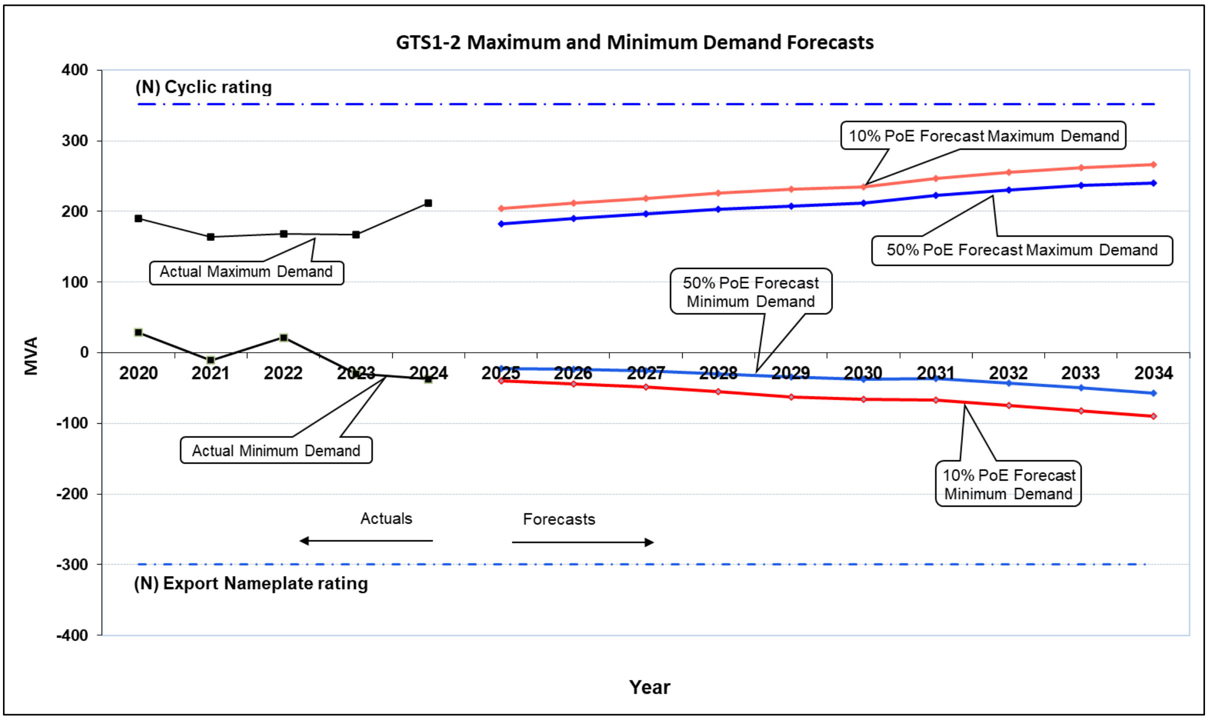
The transformer nameplate ratings have been used for reverse power flows and reflect the thermal ratings for export, as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The 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 Peak Forecasts

This bus group supplies Powercor's zone substations at Ford North Shore, Waurn Ponds, Colac, Mt Gellibrand, Gheringhap, Torquay and Winchelsea and 66kV 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 209.6 MW (211.9 MVA) in summer 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).



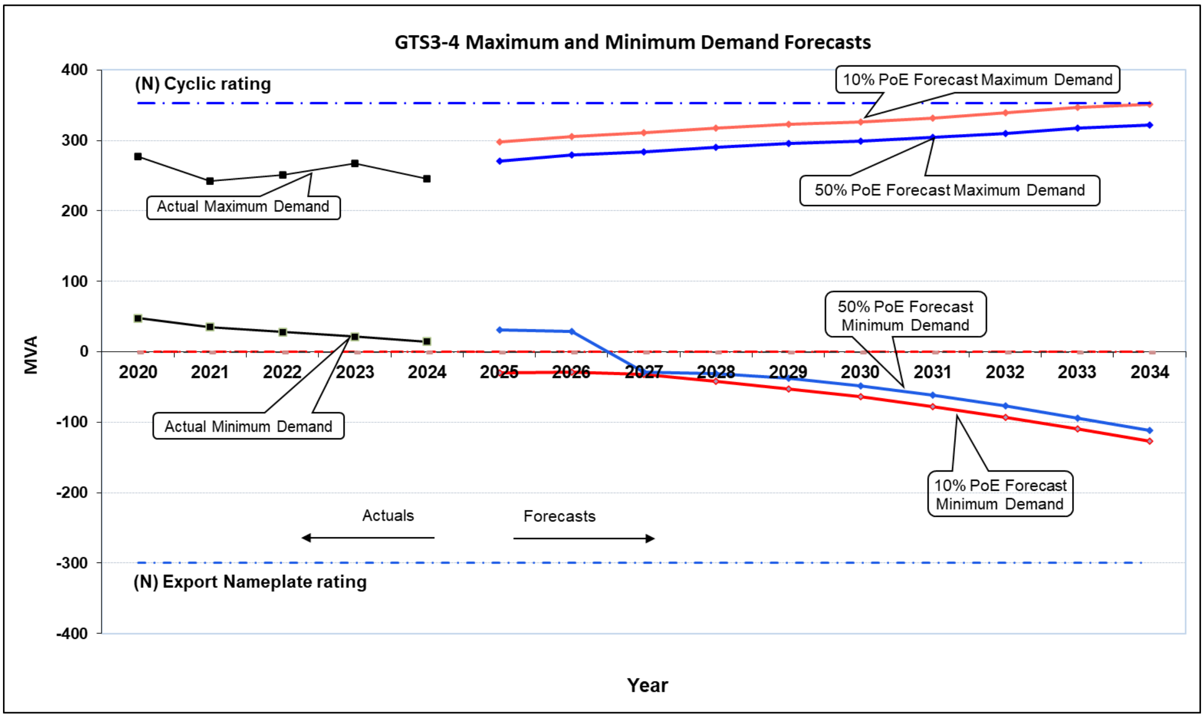
The (N) import rating on the chart indicates the maximum demand that can be supplied from GTS bus 1&2 with two transformers in service. The graph shows there is sufficient capacity (N rating) at the station to meet maximum demand over the forecast period.

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 Peak Forecasts

This bus group supplies Powercor's zone substations at Geelong East, Geelong City, Geelong B, Corio and 66kV customer substation Ford Norlane. The peak load on the GTS 3 & 4 Bus group reached 235.4 MW (245.5 MVA) in summer 2024.

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 there is sufficient capacity (N rating) at the station to meet maximum demand over the forecast period.

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 Load Summer Peak Forecasts

GTS is a summer peaking station and the maximum demand reached 438.5 MW (448.5 MVA) in Summer 2023.

It is estimated that:

- For 8 hours per year, 95% of peak demand is expected to be reached under the 50th percentile forecast.
- The station load power factor at the time of peak demand is 0.98

In relation to minimum demand, it is estimated that:

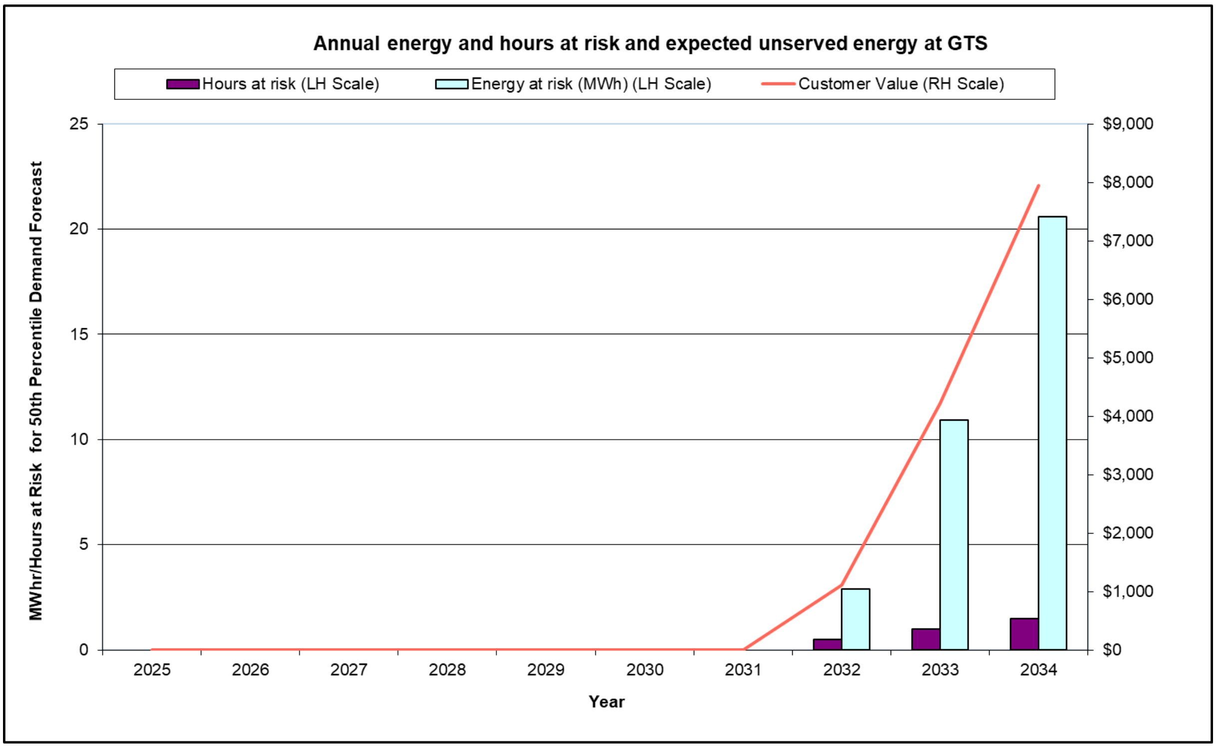
- For 2 hours per year, 95% of the minimum demand is expected to be reached.

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

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 35°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 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 $44,471 per MWh.



Key statistics relating to energy at risk and expected unserved energy for the year 2034 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	20.6	$1 million
Expected unserved energy at 50th percentile maximum demand	0.18	$7,944
Energy at risk, at 10th percentile maximum demand forecast	271.8	$12 million
Expected unserved energy at 10th percentile maximum demand	2.36	$104,770
70/30 weighted expected unserved energy value (see below)	**0.83**	**$37,000**

Under the probabilistic planning approach[72], 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[73]. The expected unserved energy cost is used to evaluate the net economic benefit of options that reduce or remove the energy at risk.

72 See section 3.

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

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)[74]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $0.04 million.

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 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.

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.

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

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 704	via 4 transformers (summer)	
Summer N-1 Station Import Rating:	524	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	524	
Summer N-1 Station Export Rating:	450	[See Note 7]
Winter N-1 Station Export Rating:	450	[See Note 7]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	444.7	459.7	470.8	483.2	493.3	501.1	516.6	529.9	543.6	552.0
50th percentile Winter Maximum Demand (MVA)	410.0	424.9	437.0	449.2	457.9	464.6	482.7	496.4	508.4	513.7
10th percentile Summer Maximum Demand (MVA)	492.0	507.8	519.1	532.0	542.3	550.4	566.8	582.4	596.5	604.9
10th percentile Winter Maximum Demand (MVA)	442.9	458.0	470.7	484.7	493.0	500.4	519.5	533.1	547.2	553.6
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	10.9	20.6
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.0	1.5
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	3.9	9.7	18.2	48.7	105.1	198.3	271.8
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	0.5	1.0	1.5	2.5	5.5	8.5	11.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.18
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.03	0.08	0.16	0.42	0.91	1.72	2.36
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	$0.01M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.02M	$0.04M	$0.08M	$0.10M
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	$0.01M	$0.01M	$0.03M	$0.04M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	34.7	45.7	65.0	88.3	109.9	131.0	147.1	169.4	196.1	224.1
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 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 winter rating is at an ambient temperature of 5 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. “Expected unserved energy” means “N-1 energy at risk” for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 266.2 MW of embedded generation capacity is installed on the AusNet sub-transmission and distribution systems connected to GNTS. It consists of:

- 196.8 MW of large-scale embedded generation, predominately solar farms; and
- 69.4 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	Existing Plant	Solar PV	85
Glenrowan West Solar Farm	Existing Plant	Solar PV	110

Magnitude, probability and impact of constraints

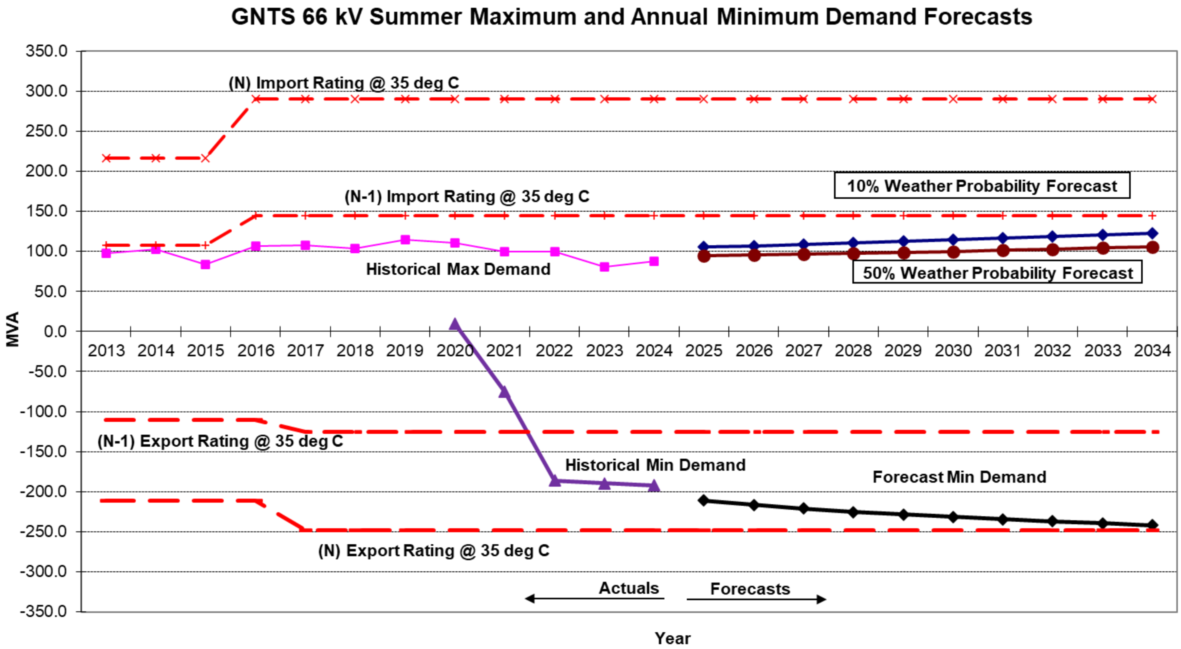
Historically, maximum demand at GNTS has occurred in winter. The rate of growth in summer and winter maximum demand at GNTS 66 kV has been low in recent years, and winter maximum demand is forecast to continue increasing slowly, averaging around 2.2% per annum for the 10 year planning horizon. Summer maximum demand is forecast to continue increasing at around 1.5% per annum for the 10 year planning horizon.

The maximum demand on the station reached 82.9 MW (87.7 MVA) in summer 2023/24 and 95.4 MW (99.3 MVA) in winter 2023.

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 35°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 demand at GNTS 66 kV is expected to exceed 95% of the 50th percentile peak demand for 5 hours per annum. The station load has a power factor of 0.95 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 48 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 as GNTS. By 2034 there is projected to be maximum of 116.8 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 898 MWh in 2034.

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.

Additional generation at the station may lead to an increased risk of terminal station transformers overloading due to reverse power flows. AusNet Services is currently assessing the costs and benefits of alleviating the export constraint and will progress to a RIT-T if initial assessments suggest that corrective action to address export constraints may be economically justified.

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	290	MVA via 2 transformers (Summer peaking)
Summer import N-1 Station Rating	145	MVA [See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating	172	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	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	94.2	95.3	96.5	97.4	98.6	100.0	101.4	102.6	104.2	105.8
50th percentile Winter Maximum Demand (MVA)	104.1	106.4	108.8	111.2	113.7	116.0	118.5	120.9	123.3	125.7
10th percentile Summer Maximum Demand (MVA)	105.4	107.0	108.8	110.6	112.4	114.4	116.4	118.4	120.5	122.4
10th percentile Winter Maximum Demand (MVA)	115.3	118.2	121.0	123.8	126.7	129.5	132.4	135.3	138.2	141.1
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	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	0.0	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	0.0	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	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	-210.9	-216.4	-221.1	-225.2	-228.3	-231.2	-234.1	-236.8	-239.4	-241.8
Maximum generation at risk under N-1 (MVA)	85.9	91.4	96.1	100.2	103.3	106.2	109.1	111.8	114.4	116.8
N-1 energy curtailment (MWh)	157606	166405	173259	179368	184745	189862	194709	199385	203631	207196
Expected volume of export energy curtailed for N-1 (MWh)	683.0	721.1	750.8	777.3	800.6	822.7	843.7	864.0	882.4	897.9

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The summer rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.65 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 sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.

6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
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.

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 143.3 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.

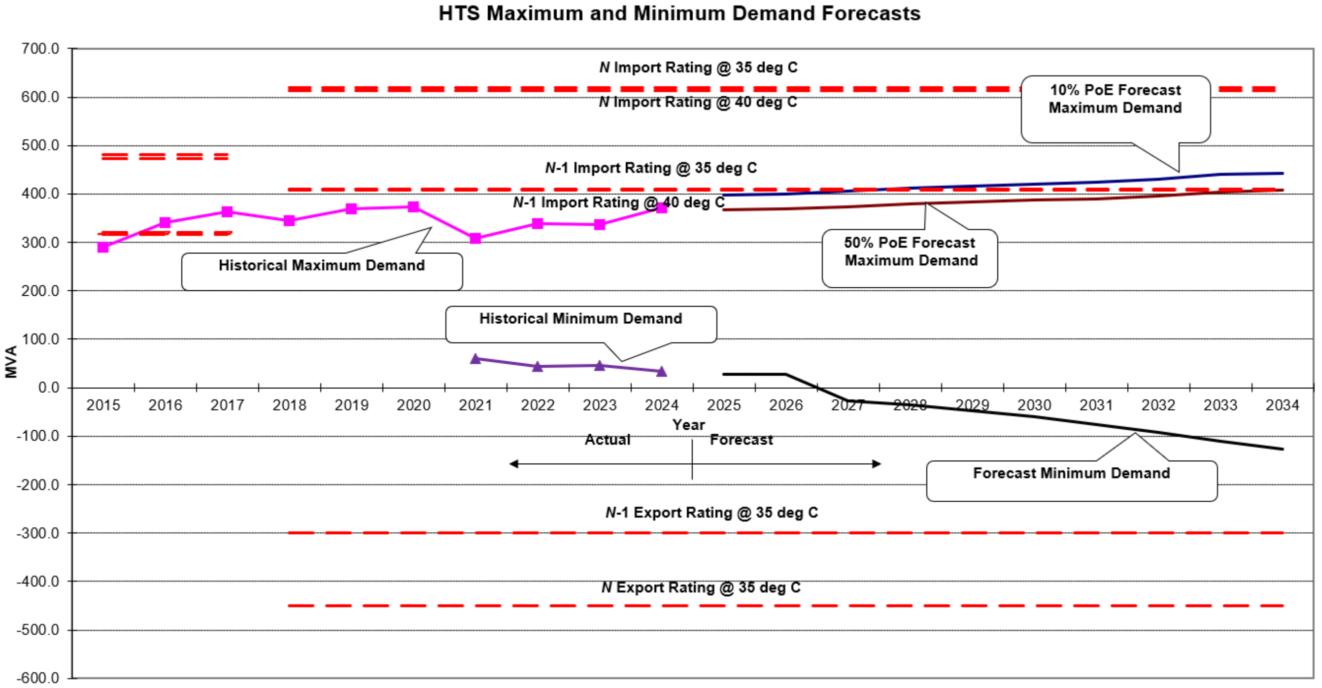
Magnitude, probability, and impact of constraints

HTS is a summer critical terminal station. The station reached a maximum demand of 360.5 MW (371.9 MVA) in summer 2024.

In 2017, AusNet Transmission Group replaced the existing HTS 220/66 kV transformers as part of their asset replacement programme. This resulted in an increase in the station ratings for summer 2018 as reflected in the graph below.

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 35°C as well as 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.

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

The station load is forecast to have a power factor of 0.97 at times of peak demand. The demand at HTS is expected to exceed 95% peak demand for approximately 31 hours per annum.

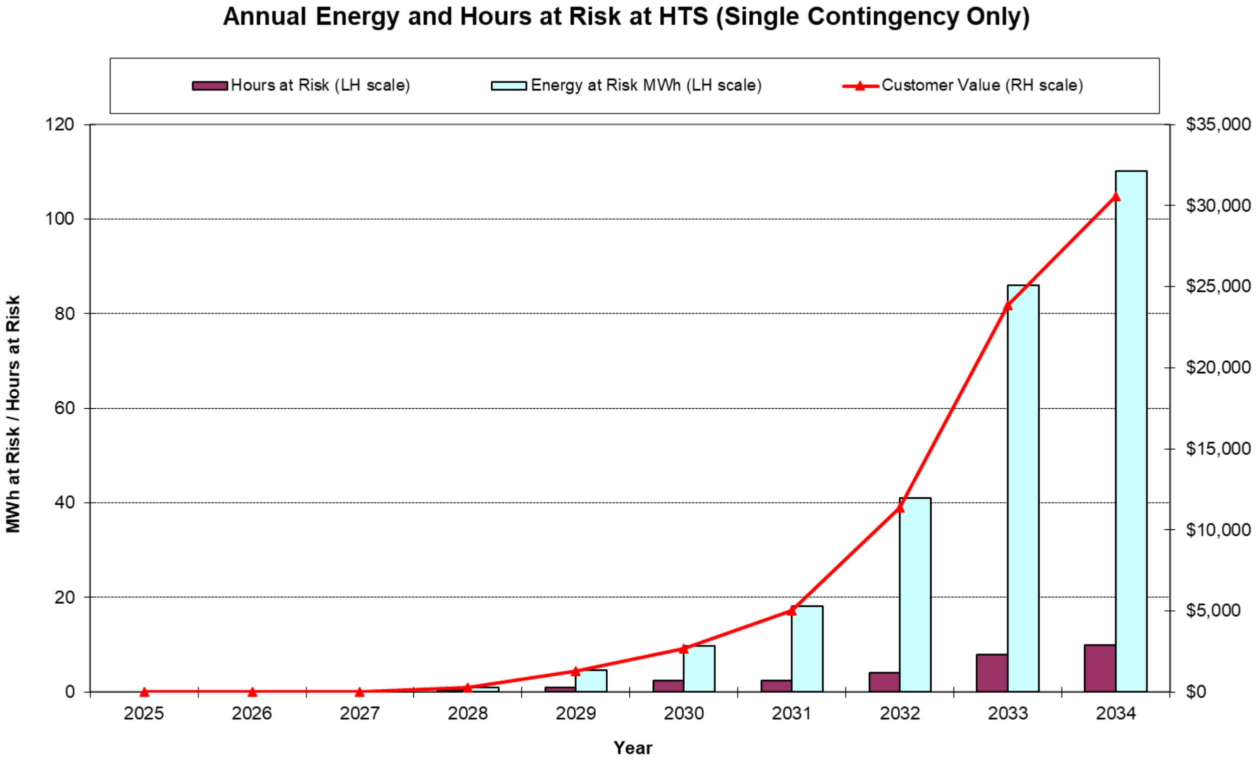
The station load is forecast to have a power factor of 0.57 at times of minimum demand. The demand at HTS is expected to reach 95% minimum demand for less than 1 hour per annum.

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 10% PoE in 2026.

The bar chart below depicts the energy at risk with one transformer out of service for the 10th percentile demand forecast, and the hours per year that the 10th percentile demand forecast is expected to exceed the (N-1) capability 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 $42,171 per MWh.

Government-led investment in infrastructure projects within the station's supply area 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 2034 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile demand forecast	0	$0
Expected unserved energy at 50th percentile demand	0	$0
Energy at risk, at 10th percentile demand forecast	110	$4.6 million
Expected unserved energy at 10th percentile demand	0.72	$30,571
70/30 weighted expected unserved energy value (see below)	**0.22**	**$9,171**

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 4.6) 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 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)[77]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $9,171. 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.

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.

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[78] load shedding scheme which is operated by AusNet Transmission Group's TOC[79] 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 conditions, via both 66 kV sub-transmission and 22/11 kV distribution networks. These plans are

75 See section 3.1.

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)

78 Overload Shedding Scheme of Connection Asset.

79 Transmission Operations Centre

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 87 MVA for summer 2025.

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 replacement of the transformers at HTS in 2017 increased the HTS rating, so the need for a new terminal station is now more likely to be driven by transmission network constraints alone and 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

As explained above, 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 (refer to Section 5.5) 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): 619 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Import Rating: 410 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 433 MVA
Summer N-1 Station Export Rating: 300 MVA [See Note 7]
Winter N-1 Station Export Rating: 300 MVA [See Note 7]

Station: HTS 66kV import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	367	369	374	379	384	387	390	396	403	408
50th percentile Winter Maximum Demand (MVA)	296	298	302	307	310	312	316	323	329	331
10th percentile Summer Maximum Demand (MVA)	397	401	405	411	416	420	423	431	440	443
10th percentile Winter Maximum Demand (MVA)	308	311	316	322	324	327	331	338	346	348
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	1	5	10	18	41	86	110
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	1	1	3	3	4	8	10
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	0.1	0.1	0.3	0.6	0.7
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value at 10th percentile demand	$0.0k	$0.0k	$0.0k	$0.3k	$1.3k	$2.7k	$5.0k	$11.4k	$23.9k	$30.6k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.1k	$0.4k	$0.8k	$1.5k	$3.4k	$7.2k	$9.2k
Hours per year that 95% of maximum demand is expected to be reached	31	31	31	31	31	31	31	32	33	31
Station load power factor at the time of maximum demand	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97

Station: HTS 66kV export	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
10th percentile minimum demand (MVA)	29	27	-27	-36	-47	-60	-75	-91	-109	-127
Maximum generation at risk under N-1 (MVA)	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
Expected volume of export energy curtailed (MWh)	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 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 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 2019 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.
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, 169 small domestic and farming customers along the line route are also supplied from this supply point.

Embedded generation

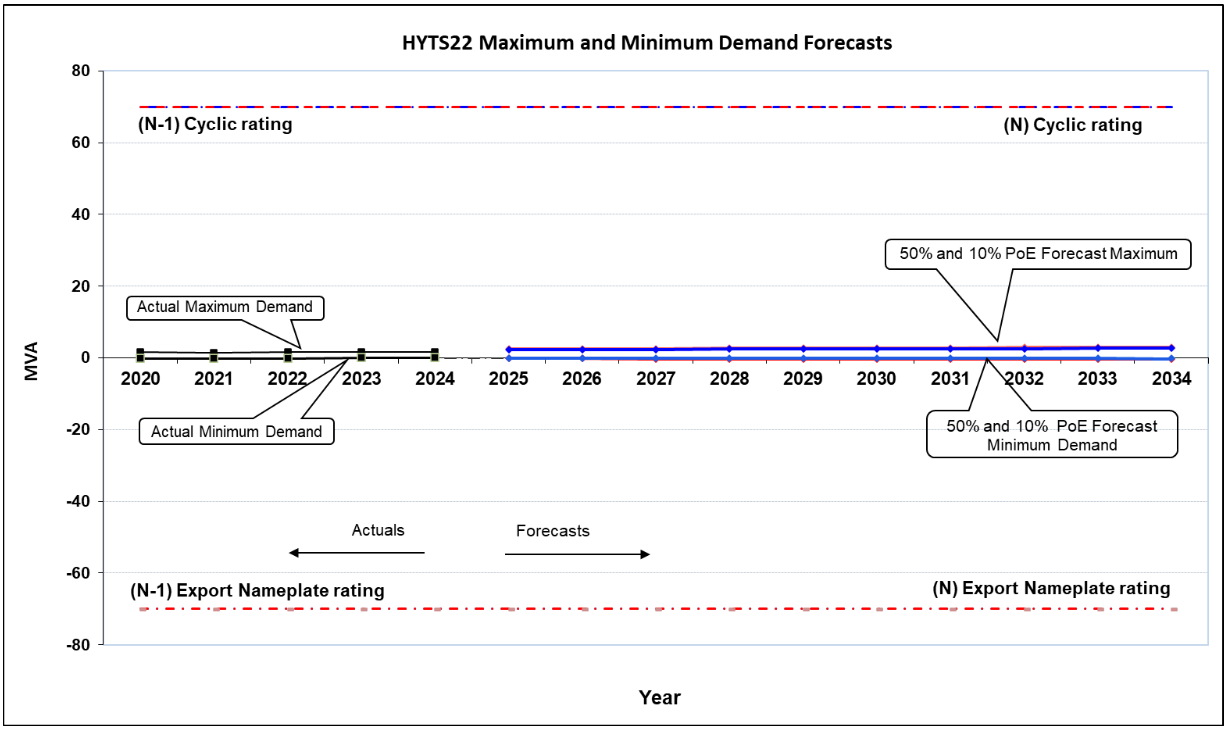
About 128 kW of rooftop solar PV is installed on the Powercor distribution system connected to HYTS 22 kV. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

Magnitude, probability and impact of constraints

The maximum demand on the station reached 1.55 MW (1.59 MVA) in winter 2023.

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 35°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 12 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 0.97

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 power factor at the time of minimum demand is 0.67

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 30,458 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 87 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 34 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

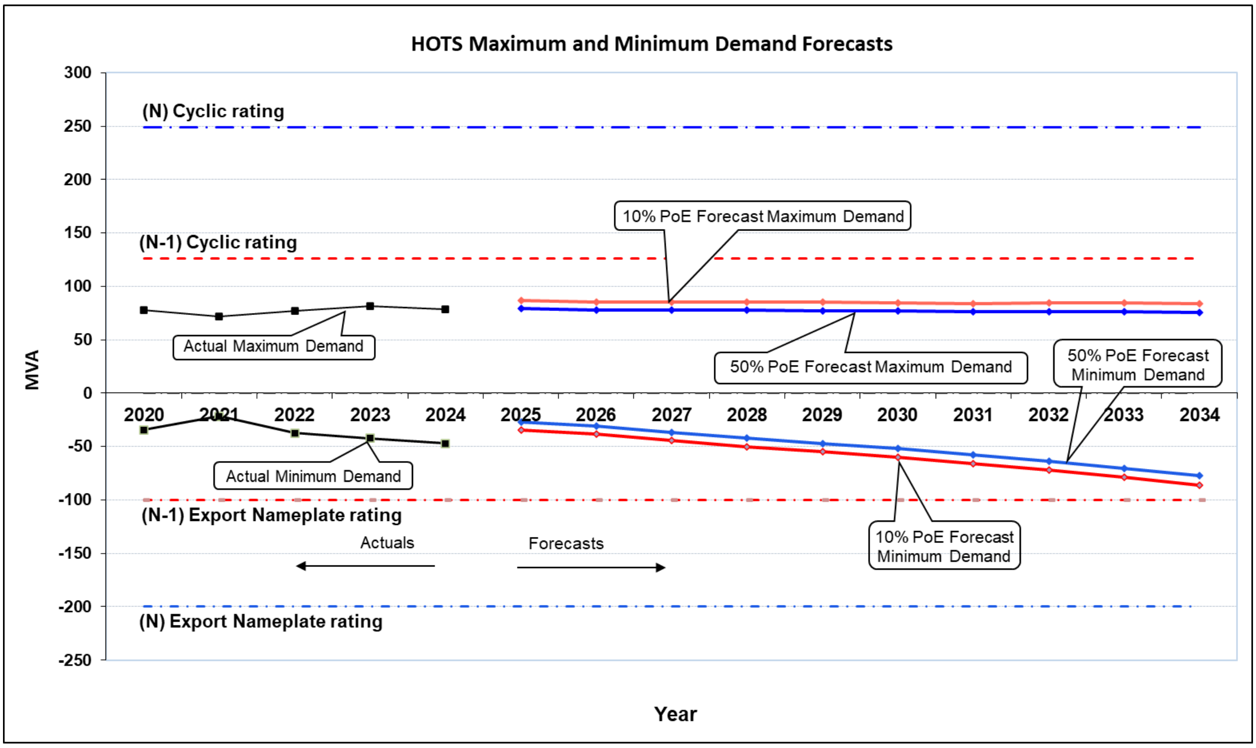
Magnitude, probability and impact of constraints

The maximum demand on the station reached 78.6 MVA in summer 2024.

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 35°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 3 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 0.998

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 0.71

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 196,275 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.

Embedded Generation

A total of 229 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to KTS 66 kV. It consists of:

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

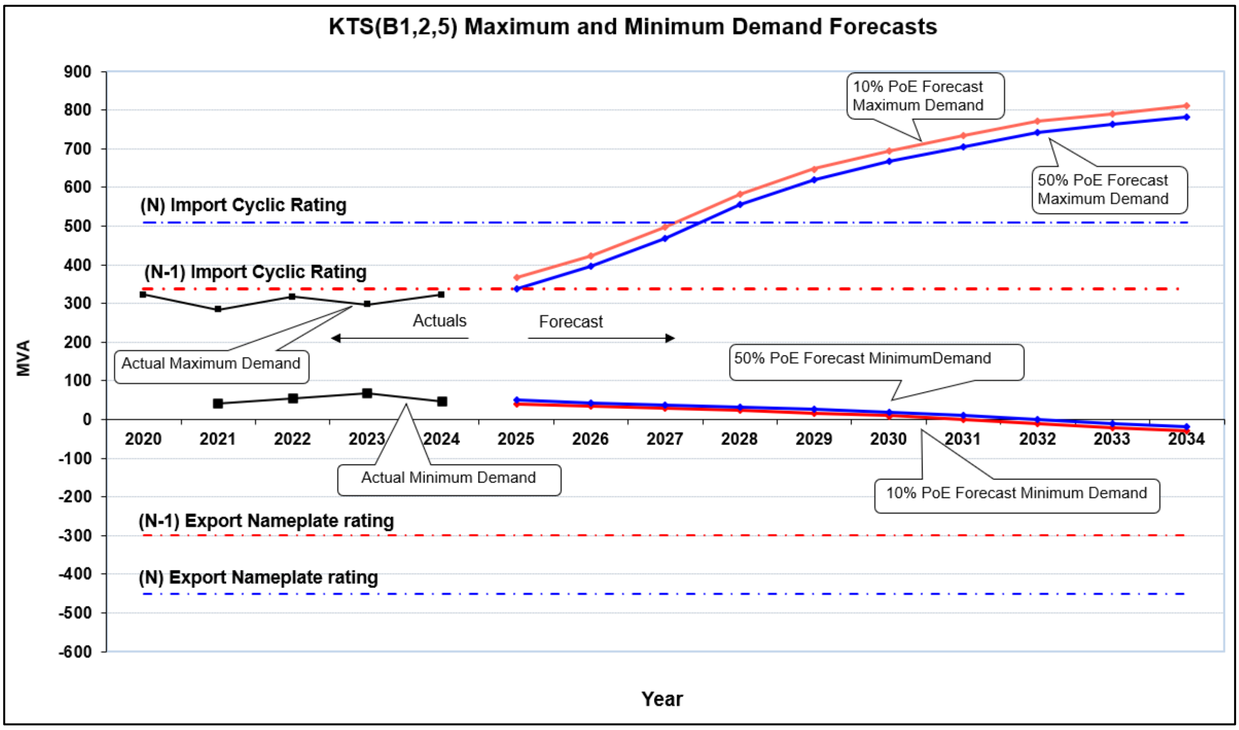
For prospective embedded generation connections, the actual availability of export capacity (which may be lower than the indicative headroom shown) will be determined through technical studies undertaken as part of the connection process. Options to address any identified export limitations will be discussed 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 35°C ambient temperature;
- actual station maximum demand reached 322.4 MW (332.6 MVA) in February 2024; and
- actual minimum demand reached 47.2 MW (47.2 MVA) in December 2023.



It is estimated that:

- For 10 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 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.

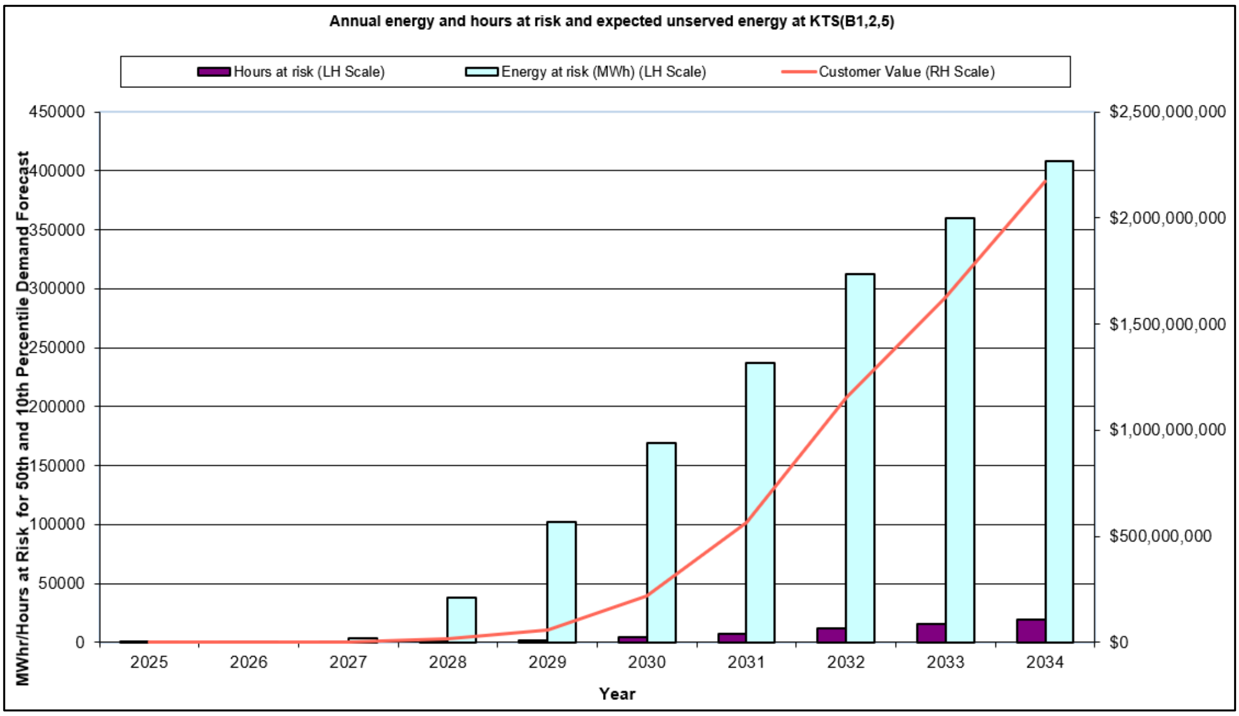
Due to new major load customers which are expected to have steady load uptake over the next ten-years, KTS (B1,2,5) is forecasted to exhibit strong load growth.

The above graph shows from 2025, there is insufficient capacity to supply the forecast maximum demand at 50th and 10th percentile temperature at KTS (B1,2,5) if a forced outage of a transformer occurs, and from 2028 the forecast maximum demand at 50th and 10th percentile temperature at KTS (B1,2,5) 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 (B1,2,5)

The bar chart below depicts the weighted average[80] 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 (B1,2,5) is $47,760 per MWh.



80 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 2028 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	34,608	$1.7 billion
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	224.9	$10.7 million
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	46,284	$2.2 billion
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	300.8	$14.4 million
Expected unserved energy at 50th percentile maximum demand under N condition	83.8	$4.0 million
Expected unserved energy at 10th percentile maximum demand under N condition	166.5	$7.9 million
70/30 weighted expected unserved energy value (see below)	**356.4**	**$17 million**

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 5.4) 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 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)[83]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2028 is $17.0 million.

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 KTS (B1,2,5) to meet maximum demand from year 2028 under system normal condition.

81 See sections 2.3 and 2.4.

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)])

N-1 System Condition

If one of the KTS 220/66 kV transformers is taken off line during peak loading times, causing the KTS (B1,2,5) import rating to be 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 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 HV feeder distribution network would be needed in the event of a transformer failure at KTS (B1,2,5), with total available transfer capability of 20 MVA in summer 2025.

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. Upgrade transformation capacity at KTS (B1,2,5) group, and install additional transformation capacity at KTS (B3,4) group at an estimated indicative capital cost of $91 million (equating to a total annual cost of approximately $7.1 million).

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 KTS (B1,2,5) 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 KTS (B1,2,5) to alleviate import constraints, it is proposed to upgrade transformation capacity at KTS (B1,2,5) group and install additional transformation capacity at KTS (B3,4)

On the basis of the present maximum demand forecasts and VCR estimates, the installation of an additional transformer and transformation upgrades at KTS by 2028 (at an annualised cost of $7.1 million) would be economically justified. As a temporary measure, the expected load at risk will be managed by load transfers on the HV distribution network and demand management.

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

84 Overload Shedding Scheme of Connection Asset.

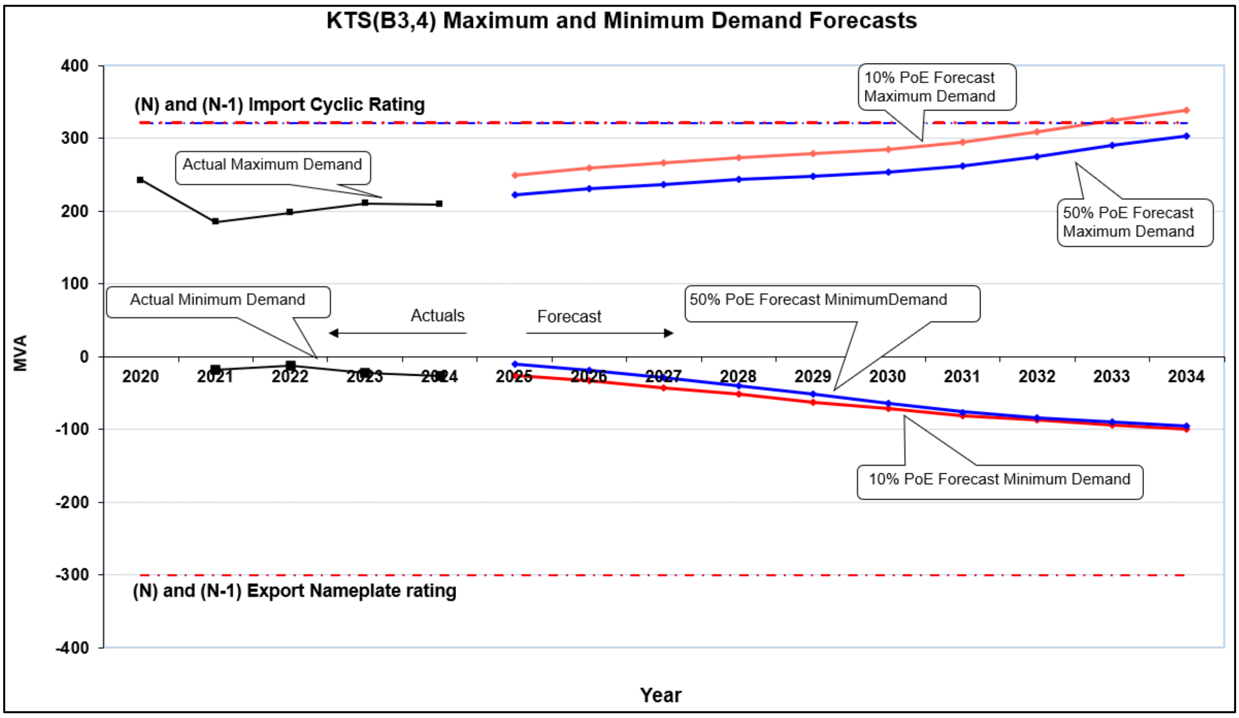
85 Transmission Operations Centre.

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 35°C ambient temperature;
- actual station maximum demand reached 206.7 MW (209.2 MVA) in February 2024; and
- actual minimum demand reached -30.3 MW (33.9 MVA) in December 2023.



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 9 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:

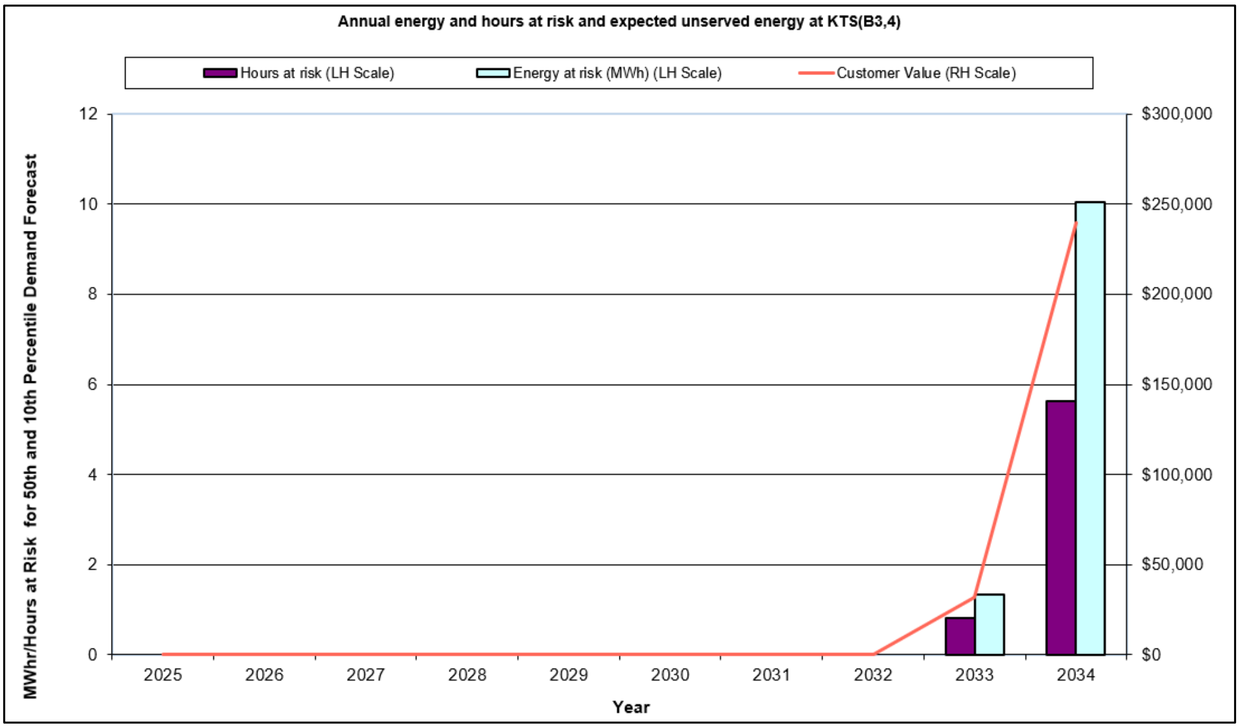
- For 3 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.89.

The above graph shows from 2033 there is insufficient import capacity at the station to meet maximum demand at the 10th percentile temperature over the forecast period for both N and N-1 conditions.

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[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 (B3,4) is $35,729 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2034 under N and N-1 outage conditions are summarised in the table below.

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)

	MWh	Valued at VCR
Expected unserved energy at 50th percentile maximum demand under N and N-1 condition	0	$ -
Expected unserved energy at 10th percentile maximum demand under N condition	16.7	$0.58 million
70/30 weighted expected unserved energy value (see below)	5.0	$0.18 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 $0.18 million.

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 KTS (B3,4) to meet maximum demand from 2033 under system normal condition.

N-1 System Condition

If one of the KTS 220/66 kV transformers is taken off line during peak loading times, causing the KTS (B3,4) 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.

87 See sections 2.3 and 2.4.

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))

90 Overload Shedding Scheme of Connection Asset.

91 Transmission Operations Centre.

Feasible options for alleviation of constraints

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

1. Install additional transformation capacity at KTS (B3,4) group at an estimated indicative capital cost of $30 million (equating to a total annual cost of approximately $2.3 million).

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 KTS (B3,4) may substitute capacity augmentations.

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 maximum demand at KTS (B3,4) to alleviate import constraints, it is proposed to install additional 220/66 kV transformer (150 MVA) at KTS (B3,4) group at an indicative capital cost of $30 million. This equates to a total annual cost of approximately $2.3 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 economically justified within the ten-year forecast period. Also, the additional transformation capacity at KTS (B3,4) group is likely to occur first under the proposal to alleviate the constraint at KTS (B1,2,5) group mentioned in the previous section.

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

Keilor Terminal Station (B125 transformer group)

Detailed Import and Export Limitation data

Distribution Businesses supplied by this station: JEN (76%), Powercor (24%)

Station operational rating (N elements in service): 509 MVA

Summer N-1 Station Import Rating: 393 MVA

N-1 Station Export Rating: 300 MVA

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	339.1	397.7	469.6	556.5	621.0	667.8	706.2	742.7	762.5	781.2
50th percentile Winter Maximum Demand (MVA)	276.0	335.0	402.2	479.9	539.2	581.7	615.4	646.9	665.0	682.4
10th percentile Summer Maximum Demand (MVA)	366.7	424.2	496.5	583.2	647.9	695.1	734.1	771.0	791.3	810.3
10th percentile Winter Maximum Demand (MVA)	288.1	347.2	414.3	492.3	551.9	594.6	628.6	660.3	678.6	696.6
N energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	83.8	462.7	2884.3	8977.1	20071.0	29064.5	39728.0
N hours at risk at 50% percentile demand (hours)	0.0	0.0	0.0	2.8	20.5	131.5	322.0	559.0	713.5	869.8
N energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	166.5	1021.1	5062.7	13563.5	27483.7	38343.2	51083.1
N hours at risk at 10% percentile demand (hours)	0.0	0.0	0.0	3.8	49.0	198.5	422.5	682.8	849.5	1015.8
N-1 energy at risk at 50% percentile demand (MWh)	0.0	148.3	2679.2	34607.6	95657.8	158302.2	217620.8	279520.8	316587.2	352968.3
N-1 hours at risk at 50th percentile demand (hours)	0.3	4.8	143.8	1000.8	1860.5	2520.0	3056.3	3451.8	3653.8	3833.0
N-1 energy at risk at 10% percentile demand (MWh)	44.5	359.4	5251.2	46283.9	115241.8	183996.4	248519.4	314632.1	353892.7	392927.5
N-1 hours at risk at 10th percentile demand (hours)	2.8	18.3	245.0	1198.8	2130.0	2837.3	3332.0	3721.3	3910.3	4090.0
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.96	17.41	308.71	1084.43	3913.26	10391.68	21887.88	31122.30	42022.25
Expected Unserved Energy at 10th percentile demand (MWh)	0.29	2.34	34.13	467.35	1770.15	6258.69	15178.89	29528.80	40643.52	53637.12
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.05M	$0.83M	$14.74M	$51.79M	$186.89M	$496.28M	$1045.31M	$1486.33M	$2006.88M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.11M	$1.63M	$22.32M	$84.54M	$298.90M	$724.91M	$1410.22M	$1941.04M	$2561.58M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.00M	$0.07M	$1.07M	$17.02M	$61.61M	$220.49M	$564.87M	$1154.79M	$1622.74M	$2173.29M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
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 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 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 2019 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 (47%), Powercor (63%)

Station operational rating (N elements in service): 321 MVA

Summer N-1 Station Import Rating: 321 MVA

N-1 Station Export Rating: 300 MVA

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	222.7	230.7	237.0	243.4	248.4	252.8	262.1	274.5	290.2	303.7
50th percentile Winter Maximum Demand (MVA)	194.2	206.4	215.5	223.7	231.0	237.1	246.2	258.0	273.1	287.6
10th percentile Summer Maximum Demand (MVA)	249.2	258.5	266.4	273.6	279.3	284.6	295.1	308.9	325.0	338.7
10th percentile Winter Maximum Demand (MVA)	203.9	216.7	226.0	234.5	242.2	248.5	257.9	269.6	285.0	300.2
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	2.2	16.7
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	0.5	2.0
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	2.2	16.7
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	0.5	2.0
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	2.21	16.74
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	$0.08M	$0.60M
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	$0.02M	$0.18M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
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 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 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 2019 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.

KERANG TERMINAL STATION (KGTS) 66kV & 22kV

Kerang Terminal Station (KGTS) 66 kV and 22 kV consists of three 35 MVA 235/66/22 kV transformers and is the main source of supply for 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 155 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 33 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 PV	50
Swan Hill Solar Farm	Existing Plant	Solar PV	14.4
Cohuna Solar Farm	Existing Plant	Solar PV	27.3
Kerang Solar Plant	Proposed	Solar PV	30

Magnitude, probability and impact of constraints

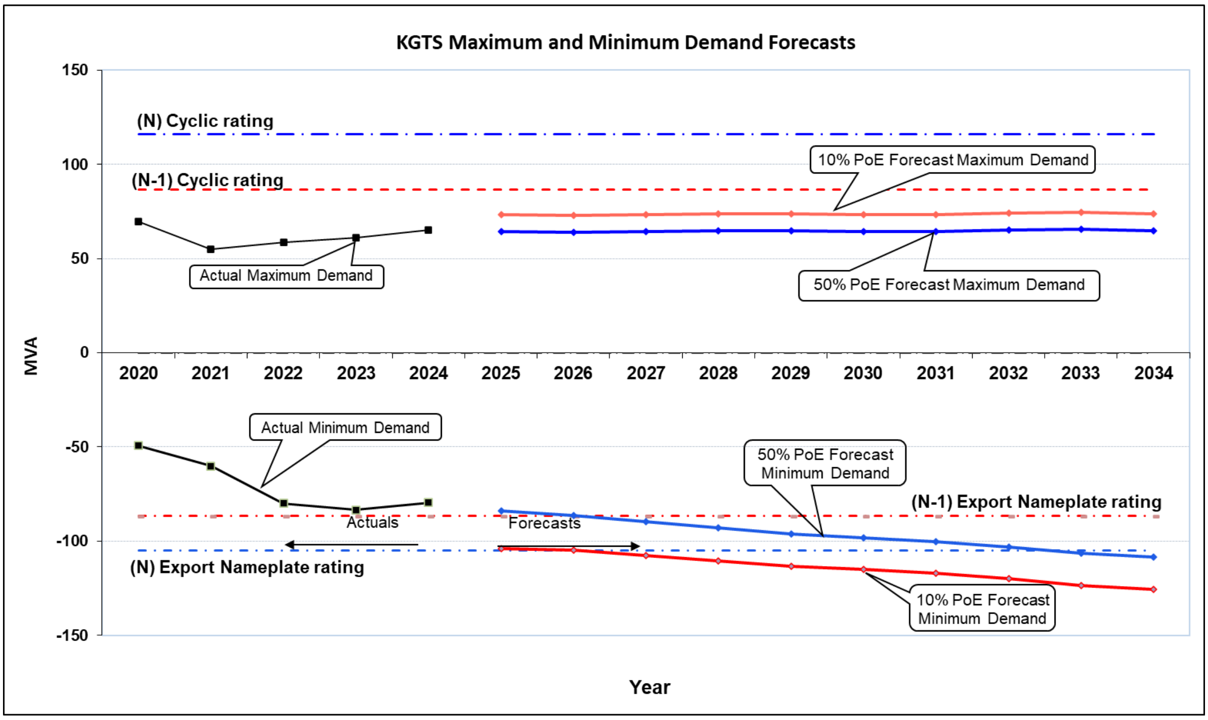
KGTS 22 & 66 kV maximum demand reached 62.9 MW (63.9 MVA, 66 kV and 22 kV networks) in summer 2024. Due to the input of generation connected to the station, reverse power flows occur during low load periods. The minimum demand at KGTS 66 kV & 22 kV reached -77.2 MW (-79.5 MVA) in October 2023.

As noted in section 4.2 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. KGTS 66 kV & 22 kV is one such station and the station's thermal ratings will be reviewed by AusNet Transmission Services.

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 35°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 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 7 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 above graph shows that there is sufficient capacity at the station to supply 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.

The graph also shows that by 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. For an outage of one transformer in 2034, 126 MVA of generation is at risk of curtailment (equating to an expected volume of generation curtailment of 255.2 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:	87	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	87	
Summer N-1 Station Export Rating:	70	[See Note 7]
Winter N-1 Station Export Rating:	70	[See Note 7]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	74.0	73.1	73.1	73.5	73.5	73.0	72.7	73.1	73.8	73.4
50th percentile Winter Maximum Demand (MVA)	64.6	64.2	64.3	64.9	64.8	64.4	64.4	65.1	65.5	64.7
10th percentile Summer Maximum Demand (MVA)	100.3	99.1	99.1	99.6	99.7	99.1	98.6	99.2	100.0	99.3
10th percentile Winter Maximum Demand (MVA)	73.5	72.9	73.2	73.8	73.7	73.2	73.3	74.0	74.5	73.6
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)	43.4	33.6	33.7	37.3	38.1	34.0	30.5	34.5	40.7	35.5
N-1 hours at risk at 10th percentile demand (hours)	9.0	7.5	7.5	8.0	8.0	7.5	6.5	7.5	8.5	7.5
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	0.00
Expected Unserved Energy at 10th percentile demand (MWh)	0.28	0.22	0.22	0.24	0.25	0.22	0.20	0.22	0.26	0.23
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	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M	$0.01M
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	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	103.8	104.8	107.6	110.7	113.3	115.0	117.1	120.0	123.4	125.7
Maximum generation at risk under N-1 (MVA)	33.8	34.8	37.6	40.7	43.3	45.0	47.1	50.0	53.4	55.7
N-1 energy curtailment (MWh)	2085.2	2322.1	2932.5	3692.2	4411.4	4920.9	5627.0	6607.1	7850.4	8685.3
Expected volume of export energy constrained (MWh)	13.6	15.1	21.8	35.5	53.6	68.1	91.2	134.0	199.4	255.2

Notes:

1. “N-1” means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 12,000 customers in Burwood, Ashwood, Glen Iris, Mount Waverley, and Surrey Hills.

Embedded generation

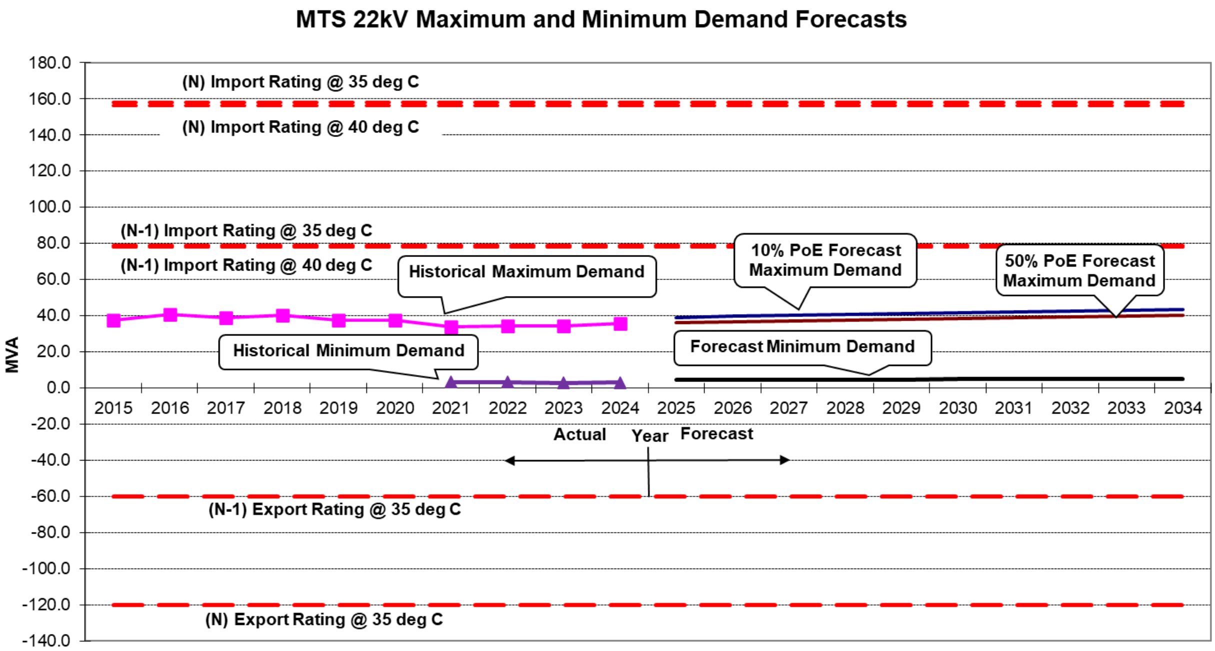
About 13.4 MW of rooftop solar PV is installed within the distribution system connected to MTS 22 kV. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW. There are no embedded generation units over 1 MW connected at MTS 22 kV.

Magnitude, probability, and impact of constraints

MTS 22 kV is a summer critical terminal station. The maximum demand in summer 2024 was 35.2 MW (35.4 MVA), which is around 1 MW higher than the summer 2023 peak.

The graph below 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 35°C as well as 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 expected to be sufficient station export capability to accommodate all embedded generation output over the ten-year planning horizon.

There is approximately 4 MVA of load transfer available at MTS 22 kV for summer 2024/25.

The station load is forecast to have a power factor of 1 at times of peak demand. The demand at MTS 22 kV is expected to exceed 95% peak demand for approximately 14 hours per annum.

The station load is forecast to have a power factor of 0.75 at times of minimum demand. The demand at MTS 22 kV is expected to reach 95% minimum demand for approximately 1 hour per annum.

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

MALVERN TERMINAL STATION 22 kV

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

Distribution Businesses supplied by this station: United Energy Distribution (100%)
Station operational rating (N elements in service): 157 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Import Rating: 78 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 83 MVA
Summer N-1 Station Export Rating: 60 MVA [See Note 7]
Winter N-1 Station Export Rating: 60 MVA [See Note 7]

Station: MTS 22kV import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	35.9	36.7	37.2	37.6	38.0	38.4	38.8	39.3	39.9	40.2
50th percentile Winter Maximum Demand (MVA)	33.3	33.9	34.4	34.7	35.2	35.6	36.0	36.5	37.0	37.1
10th percentile Summer Maximum Demand (MVA)	38.8	39.6	40.2	40.6	41.0	41.4	41.9	42.5	43.1	43.4
10th percentile Winter Maximum Demand (MVA)	35.9	36.6	37.0	37.4	37.8	38.3	38.8	39.3	39.8	39.9
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	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
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	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value at 10th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile vale + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Hours per year that 95% of 50th percentile demand is expected to be reached	14	14	14	15	15	15	15	15	15	15
Station load power factor at the time of 50th percentile demand	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99

Station: MTS 22kV export	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
10th percentile minimum demand (MVA)	4.58	4.62	4.66	4.69	4.72	4.74	4.77	4.80	4.84	4.86
Maximum generation at risk under N-1 (MVA)	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

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.65 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 2019 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.
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.

MALVERN 66 kV TERMINAL STATION (MTS 66 kV)

MTS 66 kV is the main source of supply for over 80,000 customers in Elsternwick, Caulfield, Carnegie, Malvern East, Ashburton, Chadstone, Oakleigh, Ormond, Murrumbeena, Hughesdale, and Bentleigh East.

Embedded generation

About 57.7 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.

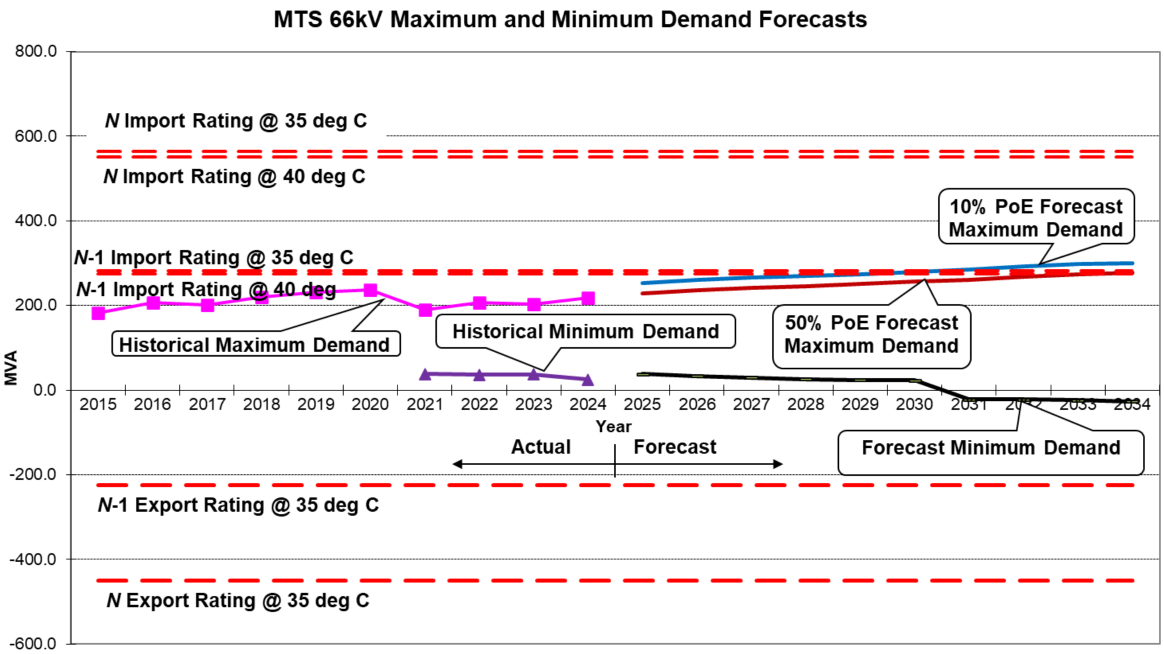
There are no embedded generation units over 1 MW connected at MTS 66 kV.

Magnitude, probability, and impact of constraints

MTS 66 kV is a summer critical terminal station. The maximum demand in summer 2024 was 213 MW (217.4 MVA), which was 13 MW higher than the summer 2023 peak. 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 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 35°C as well as 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 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 2024/25.

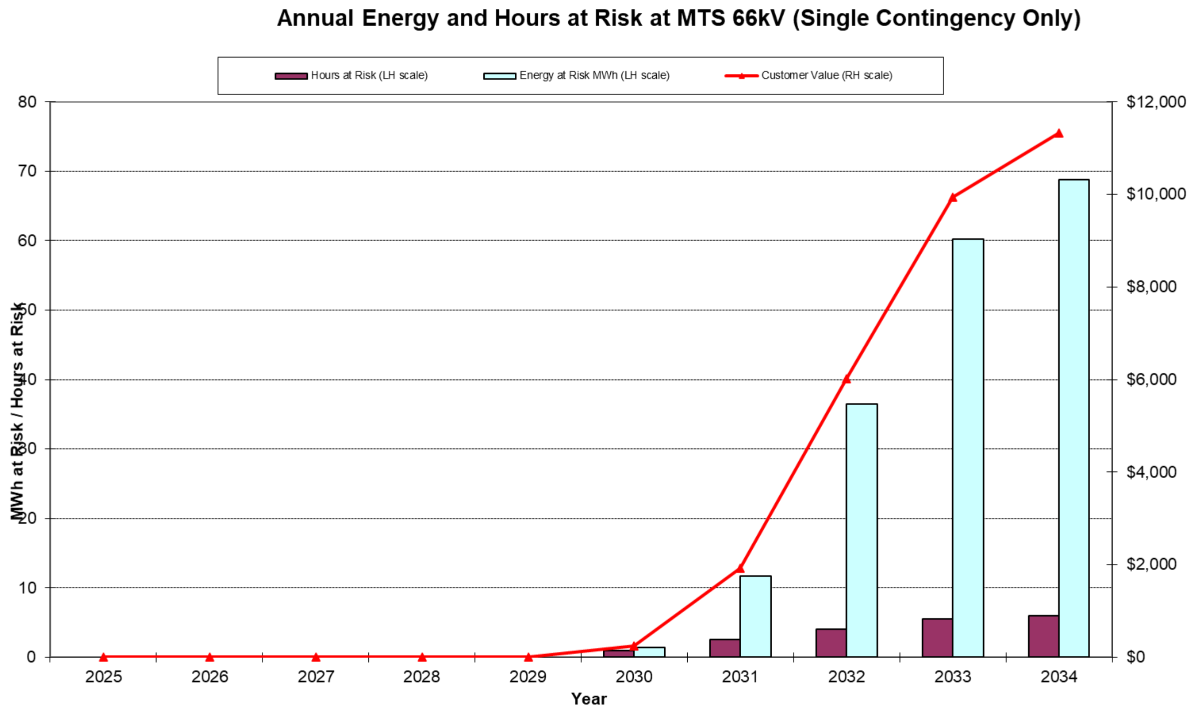
The graph shows that with one transformer out of service, the maximum demand at MTS is expected to remain within the (N-1) station import rating until summer 2030.

The station load is forecast to have a power factor of 0.99 at times of peak demand. The demand at MTS is expected to exceed 95% peak demand for approximately 16 hours per annum.

The station load is forecast to have a power factor of 0.89 at times of minimum demand. The demand at MTS is expected to reach 95% minimum demand for approximately 2 hours per annum.

The bar chart below depicts the energy at risk with one transformer out of service for the 10th percentile demand forecast, and the hours per year that the 10th percentile demand forecast is expected to exceed the (N-1) capability rating. The line graph shows the value to consumers of the expected unserved energy in each year for the 10th percentile demand forecast, valued at the VCR for this terminal station, which is $37,482 per MWh.

Government-led investment in infrastructure projects within the station's supply area is expected to further increase demand at MTS. 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 2034 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile demand forecast	0	$0
Expected unserved energy at 50th percentile demand	0	$0
Energy at risk, at 10th percentile demand forecast	69	$2.6 million
Expected unserved energy at 10th percentile demand	0.3	$11,328
70/30 weighted expected unserved energy value (see below)	**0.1**	**$3,400**

Under the probabilistic planning approach[92], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[93]. 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)[94]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $3,400.

On the basis of the current forecasts, the need for augmentation of MTS 66 kV to alleviate import constraints is not expected to arise over the next ten years.

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.

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, import and export constraints.

92 See section 3.1.

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

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

MALVERN TERMINAL STATION 66 kV

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

Distribution Businesses supplied by this station: United Energy Distribution (100%)
Station operational rating (N elements in service): 564 MVA via 2 transformers (Summer peaking)
Summer N-1 Station Import Rating: 282 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 322 MVA
Summer N-1 Station Export Rating: 225 MVA [See Note 7]
Winter N-1 Station Export Rating: 225 MVA [See Note 7]

Station: MTS 66kV import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	229	237	242	246	251	256	260	268	274	277
50th percentile Winter Maximum Demand (MVA)	188	197	206	217	226	236	242	247	254	259
10th percentile Summer Maximum Demand (MVA)	252	261	266	269	273	279	285	293	299	300
10th percentile Winter Maximum Demand (MVA)	197	207	216	227	236	246	252	259	266	270
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	1	12	36	60	69
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	1	3	4	6	6
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	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value at 10th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.2k	$1.9k	$6.0k	$9.9k	$11.3k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile vale + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.1k	$0.6k	$1.8k	$3.0k	$3.398k
Hours per year that 95% of 10th percentile demand is expected to be reached	16	17	16	14	13	13	14	14	13	14
Station load power factor at the time of 10th percentile demand	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98

Station: MTS 66kV export	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
10th percentile minimum demand (MVA)	38.44	33.51	29.66	25.72	23.71	22.87	-21.97	-22.08	-23.93	-26.82
Maximum generation at risk during N-1 (MVA)	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

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.65 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 2019 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.
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.

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 548 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
- 260.9 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.

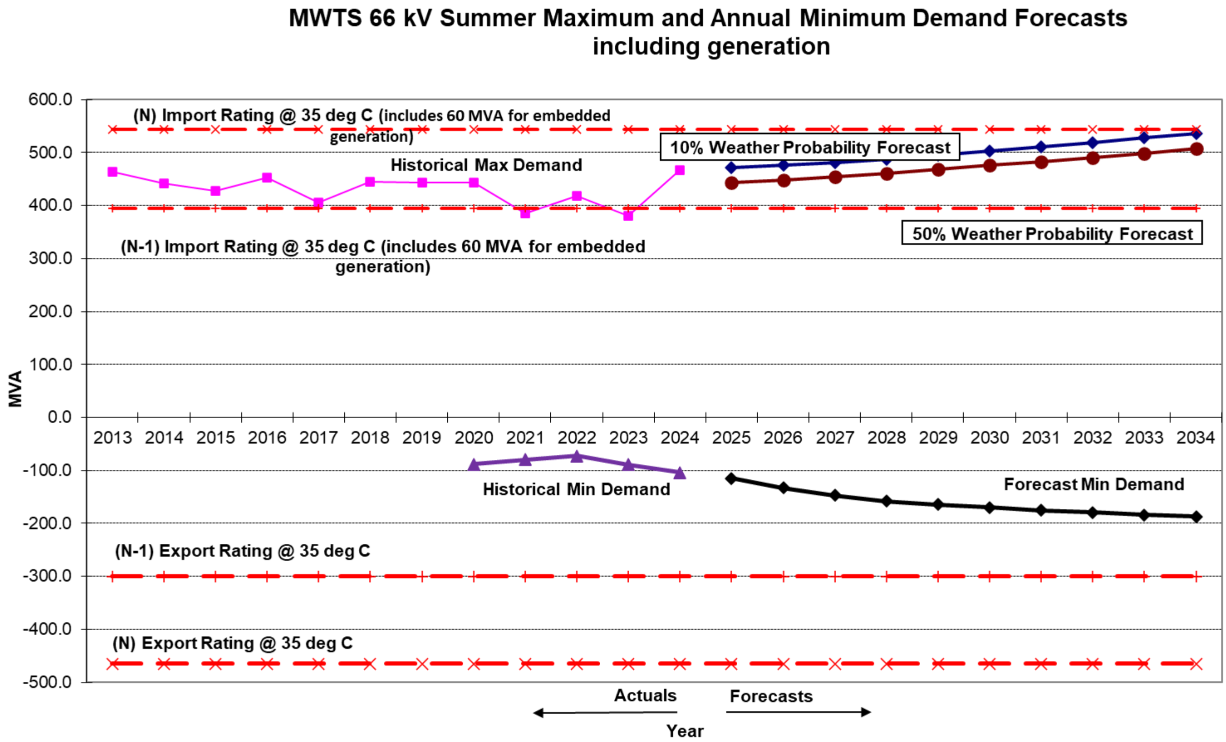
Maximum demand at MWTS 66 kV typically occurs in summer. The station reached a maximum demand of 461.9 MW (467.3 MVA) in summer 2023/24 which is the highest annual maximum demand recorded to date. The maximum demand period is usually quite short and coincides with a few weeks of peak tourism from Christmas 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 take into account 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 395 MVA "N–1" import rating includes the 335 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 35°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.



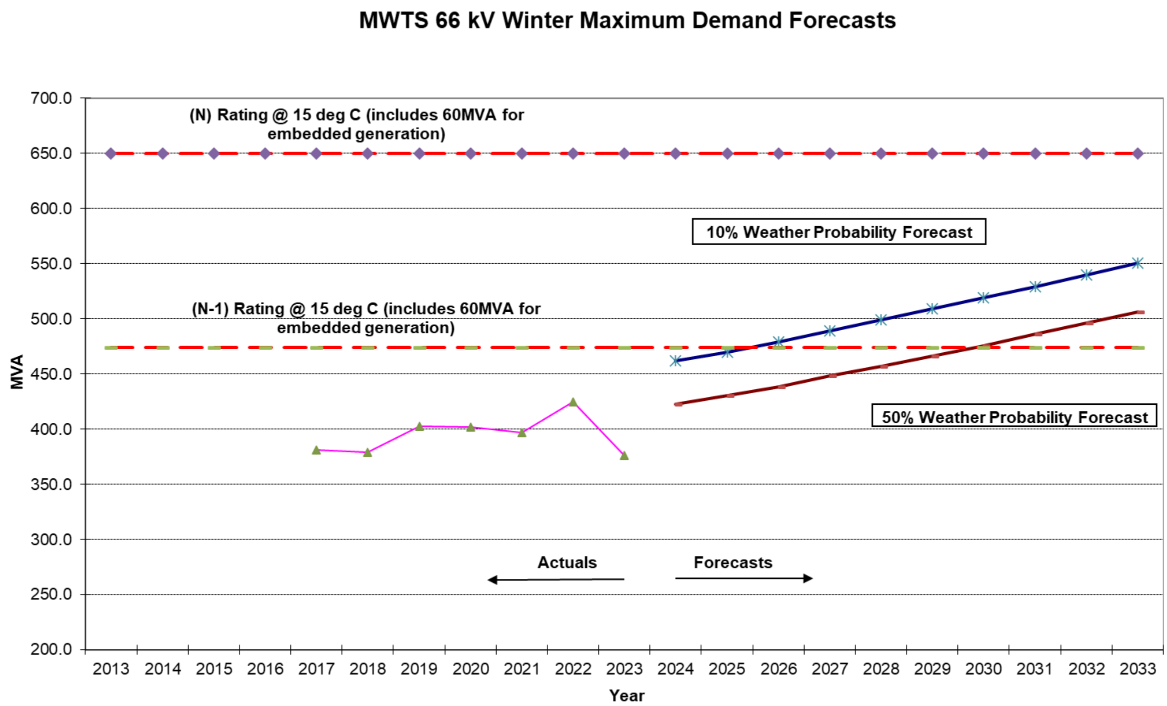
The station load has a power factor of 0.99 at maximum demand. MWTS 66 kV demand is expected to exceed 95% of the 50th percentile peak demand for 5 hours per annum.

In relation to minimum demand, it is estimated that:

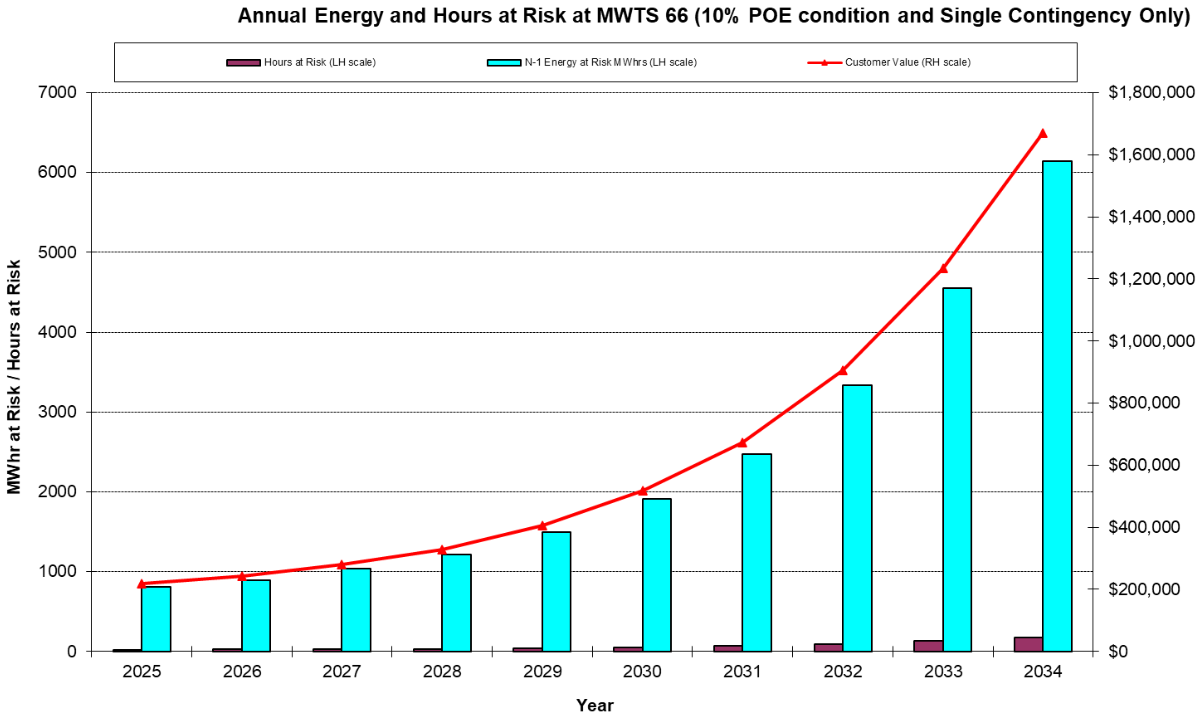
- For 33.75 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.90 at the time of minimum demand.

Minimum demand levels remained well within the station's operational "N" and "N-1" export ratings. This trend is expected to continue into the future 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 and is expected to remain well below its "N" rating under both 50th percentile and 10th percentile winter maximum demand forecasts for the 10-year 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 $41,799 per MWh.



Key statistics relating to energy at risk and expected unserved energy for the year 2034 under "N-1" outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	2,008	$83.4 million
Expected unserved energy at 50th percentile maximum demand	13.3	$0.56 million
Energy at risk, at 10th percentile maximum demand forecast	6,146	$257 million
Expected unserved energy at 10th maximum percentile demand	40.7	$1.7 million
70/30 weighted expected unserved energy value (see below)	**21.5**	**$0.9 million**

Under the probabilistic planning approach[95], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[96]. 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

95 See section 3.1.

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

0.3 to the 50th and 10th percentile expected unserved energy estimates (respectively)[97]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $0.9 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[98] to protect the connection assets from overloading[99], 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: Bairnsdale Power Station is not currently contracted to provide network support services to AusNet Services. A feasible option would be to recontract network support services from Bairnsdale or another network support service provider in the area. AusNet Services published Stage 1, the non-network options report, of a regulatory investment test for distribution (RIT-D) to address sub-transmission limitations in the East Gippsland area. Subsequently, AusNet decided not to proceed with the RIT-D project given the rapidly changing generation proposals in the region. AusNet will re-evaluate the network constraints, and may publish another RIT-D in future. Continued availability of Bairnsdale or other embedded generation network support over the ten year planning horizon will lessen the need for network augmentation.

2. Subject to availability, an AusNet Transmission Services spare 220/66 kV transformer for rural areas (refer section 4.7) can be used to temporarily replace a failed transformer.

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

4. Installation of Power Factor Correction Capacitors: As the station is currently running with a power factor of around 0.99 at the summer peak, the use of additional capacitors to

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

98 Transmission Operation Centre.

99 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.

further improve the power factor and to reduce the MVA loading on the transformers will provide only marginal benefits.

5. Load transfers: Only 5.9 MVA of load can be shifted away from MWTS using the existing 22 kV distribution network, so this option does not make a material contribution to managing the risk at MWTS.

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 to exceed the expected value of unserved energy in 2034. In view of this, and the possible availability of network support in the area, it is unlikely that implementing a network solution to alleviate import constraints will be economic over 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 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	544	MVA via 3 transformers and embedded generation
Summer import N-1 Station Rating	395	MVA via 2 transformers and embedded generation
Winter import N-1 Station Rating	474	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	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
50th percentile Summer Maximum Demand (MVA)	443.5	448.3	454.5	461.1	468.4	475.8	483.5	490.5	499.0	507.4
50th percentile Winter Maximum Demand (MVA)	430.2	438.7	448.0	457.0	466.4	475.8	486.0	496.1	506.3	516.7
10th percentile Summer Maximum Demand (MVA)	472.4	476.5	481.9	487.9	494.9	502.7	510.8	519.1	527.5	536.2
10th percentile Winter Maximum Demand (MVA)	470.2	479.4	489.4	499.1	509.2	519.1	529.4	540.0	550.7	561.5
N - 1 energy at risk at 50th percentile demand (MWh)	304	374	472	586	723	880	1,069	1,276	1,574	2,008
N - 1 hours at risk at 50th percentile demand (hours)	15.0	16.2	17.8	19.4	21.7	25.0	29.6	33.2	46.1	62.7
N - 1 energy at risk at 10th percentile demand (MWh)	805	895	1,034	1,213	1,491	1,907	2,476	3,339	4,547	6,146
N - 1 hours at risk at 10th percentile demand (hours)	23.2	24.7	27.5	31.4	36.4	52.8	68.6	90.4	128.5	170.8
N and N-1 Expected Unserved Energy at 50th percentile demand (MWh)	2.0	2.5	3.1	3.9	4.8	5.8	7.1	8.5	10.4	13.3
N and N-1 Expected Unserved Energy at 10th percentile demand (MWh)	5.3	5.9	6.8	8.0	9.9	12.6	16.4	22.1	30.1	40.7
N and N-1 Expected Unserved Energy value at 50th percentile demand	$0.08M	$0.10M	$0.13M	$0.16M	$0.20M	$0.24M	$0.30M	$0.35M	$0.44M	$0.56M
N and N-1 Expected Unserved Energy value at 10th percentile demand	$0.22M	$0.25M	$0.29M	$0.34M	$0.41M	$0.53M	$0.69M	$0.92M	$1.26M	$1.70M
N and N-1 Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.13M	$0.15M	$0.18M	$0.21M	$0.26M	$0.33M	$0.41M	$0.52M	$0.68M	$0.90M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum demand (MVA)	-115.1	-133.1	-147.2	-157.9	-164.5	-169.5	-175.0	-179.6	-184.1	-187.3
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 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 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 2019 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.

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.

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

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

Embedded generation

A total of 49.7 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
- 20.7 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 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

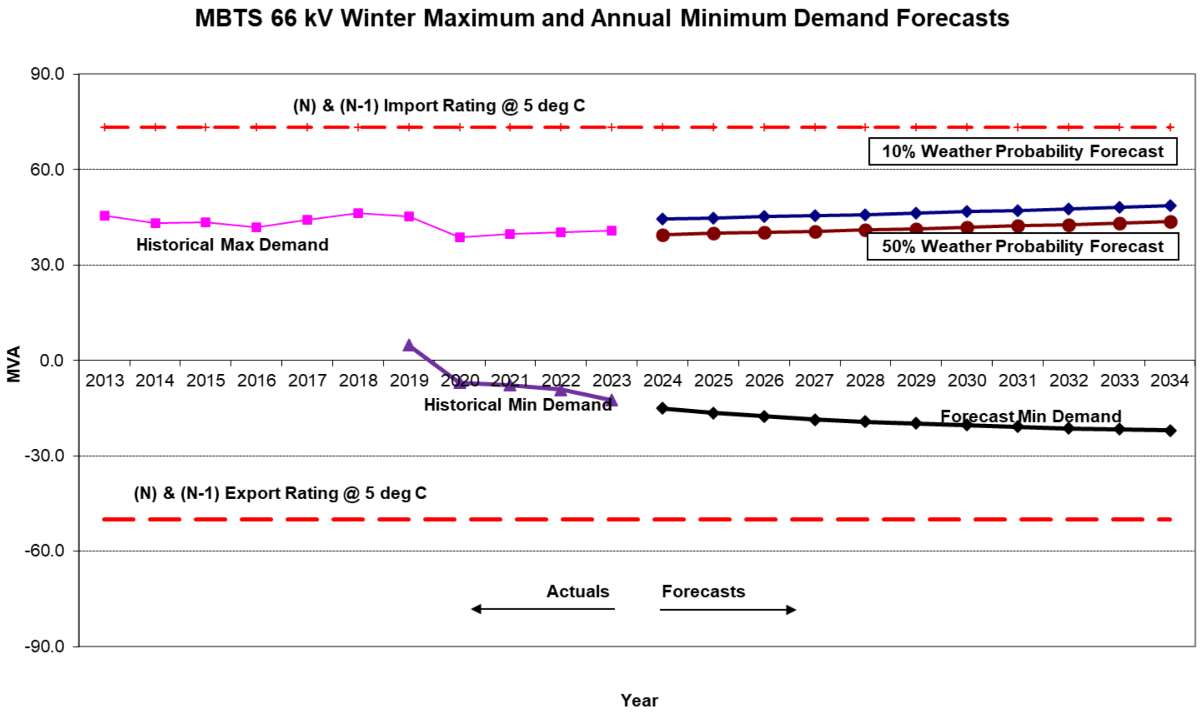
Magnitude, probability and impact of constraints

Maximum demand at MBTS occurs in Winter, and is forecast to remain flat for the next 10 years. Maximum demand at the station reached 47.9 MVA in winter 2012. The recorded maximum demand in winter 2023 was 40.9 MW (40.9 MVA), which remains lower than the 2012 maximum demand. The summer peak demand is around 20% 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. With maximum demand forecast to increase 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 4 hours per annum.

In relation to minimum demand, it is estimated that:

- For 35.5 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.93 at the time of minimum demand.

The above analysis does not include the possibility of loss of load for the short period of about 4 hours that it takes to change over from the in-service transformer to the hot spare transformer. The 66 kV tie line to Glenrowan Terminal Station can support about 25 MW of MBTS load and this tie line is operated normally closed so if the load is below this limit there will not be any loss of customer load during a transformer outage. Clover Power Station can generate around 26 MW and so any generation would also minimise the likelihood of the loss of customer load during a transformer outage.

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

The energy at risk for a major transformer outage[100] in this situation (taking account of the limited 66 kV tie line capability) is significant at around 1,329 MWh in winter 2024. However, given that the hot spare transformer can be made available within 4 hours, the expected outage duration in the case of a major transformer failure at MBTS is 4 hours (rather than 2.65 months). Accordingly, the probability of the transformer being unavailable in this particular case is only 0.000457%. The expected unserved energy at MBTS is therefore approximately 0.00627 MWh in 2024 and this is estimated to have a value to consumers of approximately $234 (based on a value of customer reliability of $38,657/MWh).

Full switching of the hot spare transformer with new 220 kV and 66 kV circuit breakers would eliminate this risk but this is estimated to cost around $4 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.

100 In this report, “major transformer outage” means an outage that has a mean duration of 2.65 months.

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 5,683 customers in Red Cliffs and the surrounding area. The station supply area includes Red Cliffs, Colignan and Werrimull.

Embedded generation

A total of 26 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
- 18.6 MW of rooftop solar PV, including all the residential and small-scale commercial rooftop PV systems that are smaller than 1 MW.

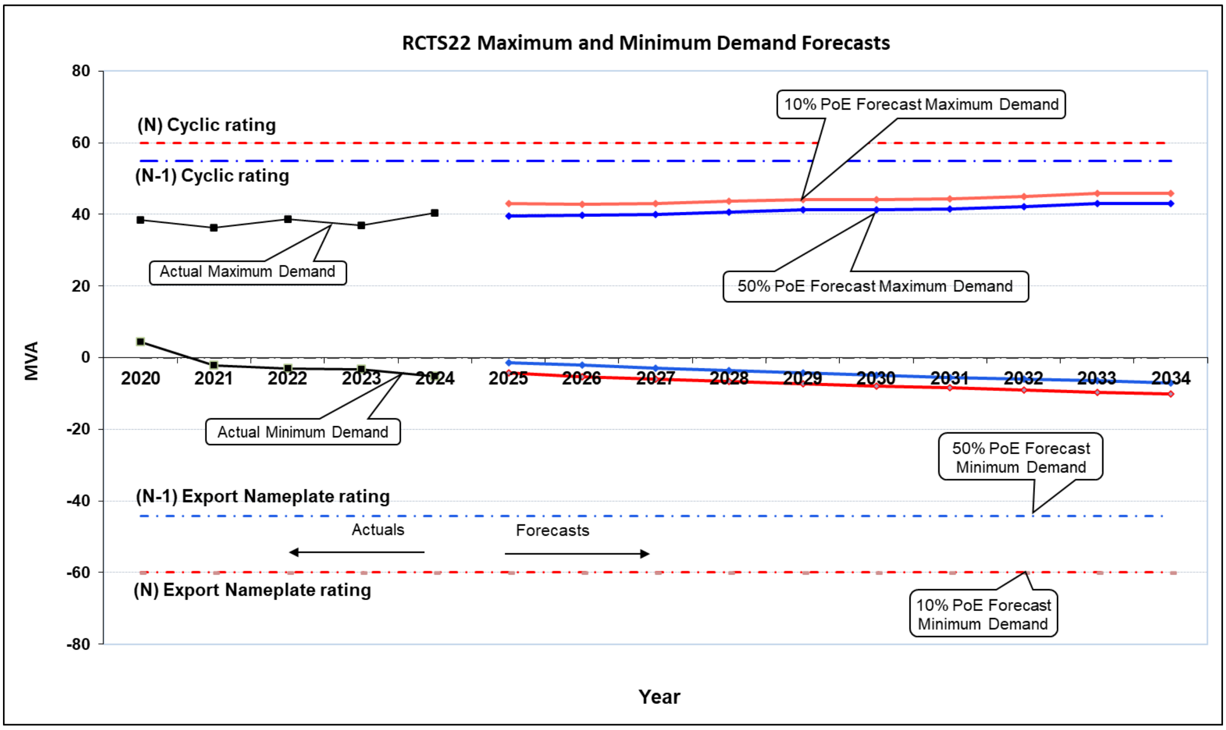
Magnitude, probability and impact of constraints

The maximum demand for the RCTS 22 kV network reached 40.52 MVA in summer 2024. The minimum demand at the station was -5.12 MVA in October 2023.

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 35°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 7 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station transformer power factor at the 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 0.68.

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 26,503 customers in Red Cliffs and the surrounding area. The station supply area includes Merbein, Mildura and Robinvale.

Embedded generation

A total of 239.1 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
- 47.6 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 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 PV	90
Yatpool Solar Farm	Existing Plant	Solar PV	94
Robinvale Solar Farm	Existing Plant	Solar PV	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 104.6 MW (108.9 MVA) in summer 2024. 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 -163.4 MW (-171.6 MVA) in November 2023.

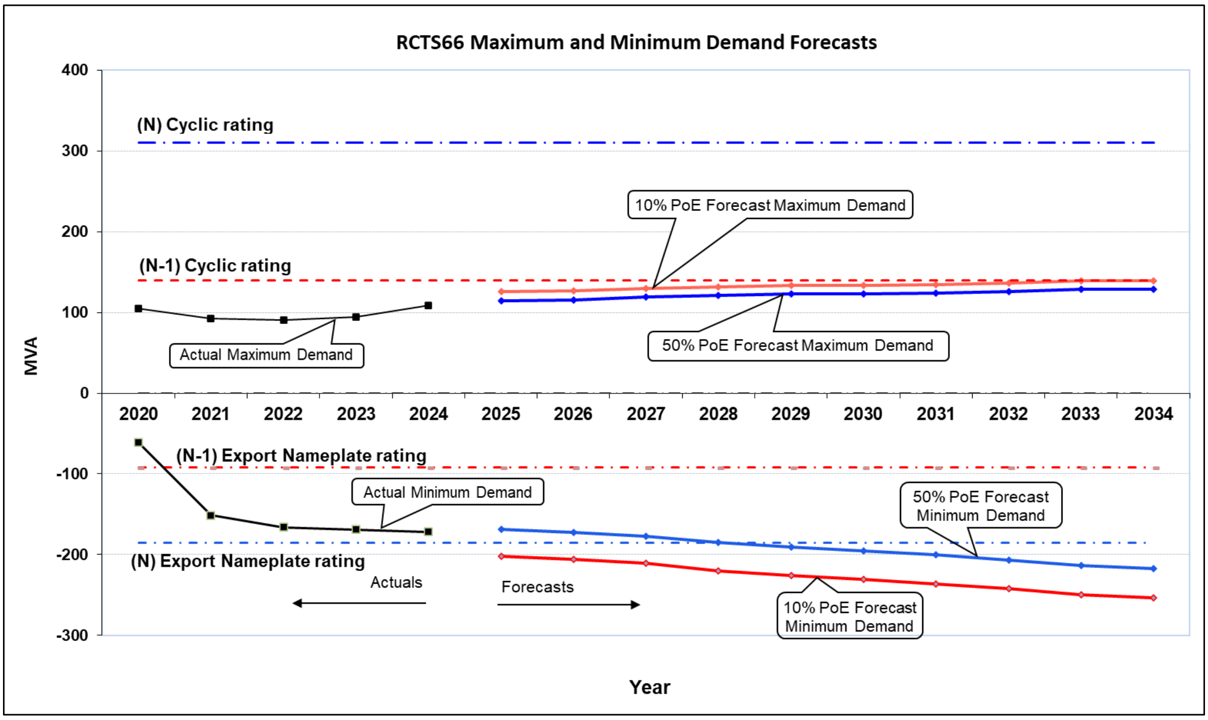
As noted in section 5.2 of this report, the connection of significant embedded generation to networks supplied from some terminal stations is expected to lead to reverse power flows that may necessitate a reduction in the ratings of some stations. RCTS 66 kV is one such station. In 2021 the station rating 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 35°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 7 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 0.96

In relation to minimum demand, it is estimated that:

- For 16 hours per year, 95% of the minimum demand is expected to be reached.
- The station power factor at the time of minimum demand is 0.95

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, there is a small amount of load at risk towards the end of the ten-year forecast period. A contingency plan to transfer RVL zone substation from RCTS to WETS (~25 MVA) will be implemented in the event of the loss of one of the RCTS 220/66 kV transformers. Generation output from the solar farms may also help supply the loads at RCTS if required.

In addition, as part of its asset renewal plan, AusNet Transmission Group is proposing to replace the existing aging transformers, which will provide additional capacity at the station in

2027. It is expected that implementation of the asset renewal plan will mitigate the 10th percentile load at risk over the ten-year planning horizon at RCTS 66 kV.

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 2034, 162 MVA of embedded generation is at risk of curtailment for the loss of one transformer at RCTS 66 kV. This equates to 77,705 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 7,546 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
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:	280	
Summer N-1 Station Export Rating:	92	[See Note 7]
Winter N-1 Station Export Rating:	92	[See Note 7]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	114.0	115.8	119.2	121.2	122.8	123.3	124.1	126.0	128.4	129.0
50th percentile Winter Maximum Demand (MVA)	84.0	87.3	89.0	90.6	91.3	91.5	92.5	94.3	95.8	95.5
10th percentile Summer Maximum Demand (MVA)	126.0	126.5	129.8	131.8	133.1	133.4	134.3	136.3	138.8	139.0
10th percentile Winter Maximum Demand (MVA)	99.7	102.2	104.2	106.1	107.1	107.4	108.6	110.6	112.4	112.0
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	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	201.9	205.9	211.1	219.9	226.1	230.7	235.9	242.3	249.7	253.9
Maximum generation at risk under N-1 (MVA)	109.9	113.9	119.1	127.9	134.1	138.7	143.9	150.3	157.7	161.9
N-1 energy curtailment (MWh)	41016.6	43510.9	47497.3	53506.0	57691.3	61075.5	64941.2	69799.9	75083.2	77705.0
Expected volume of export energy constrained (MWh)	406.9	557.3	841.4	1573.5	2294.6	2956.2	3793.6	4988.2	6586.2	7546.4

Notes:

1. “N-1” means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 6,585 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

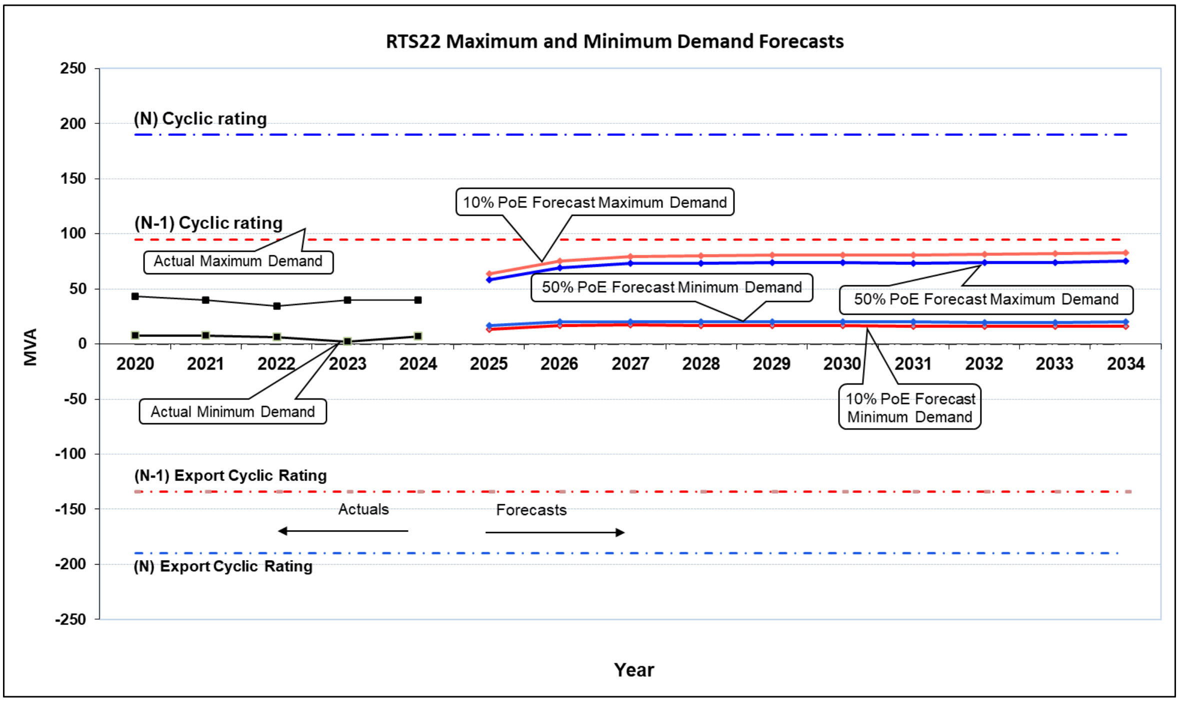
About 1.5 MW of solar PV is installed on the CitiPower distribution system connected to RTS 22. This includes all the residential and small-commercial rooftop solar PV systems (<1 MW).

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 shows the 10% and 50% probability 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 7 hours per year, 95% of peak demand is expected to be reached under the 50^{th} percentile summer forecast.
- The station load power factor at time of peak demand is 0.99.

In relation to minimum demand, it is estimated that:

- For 12 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 0.89.

The graph shows there is sufficient station import capacity to meet anticipated maximum demand, and that no customers would be at risk if a forced transformer outage occurred at RTS 22 kV over the forecast period. Accordingly, no capacity augmentation is planned at RTS 22 kV to alleviate import constraints 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.

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 149,251 customers in the Eastern Central Business District and widespread inner suburban areas in the east and south-east of Melbourne.

Embedded generation

About 27 MW of solar PV is installed on the CitiPower distribution system and 14.9 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 462.2 MW (476.8) in summer 2024. Anticipated additional loads between 2023 and 2025 are expected to lead to an increase in maximum demand, as indicated by the forecast.

RTS 66 is one of the terminal stations supplying 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 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 current forecast, this reservation is only possible for the next 12 months.

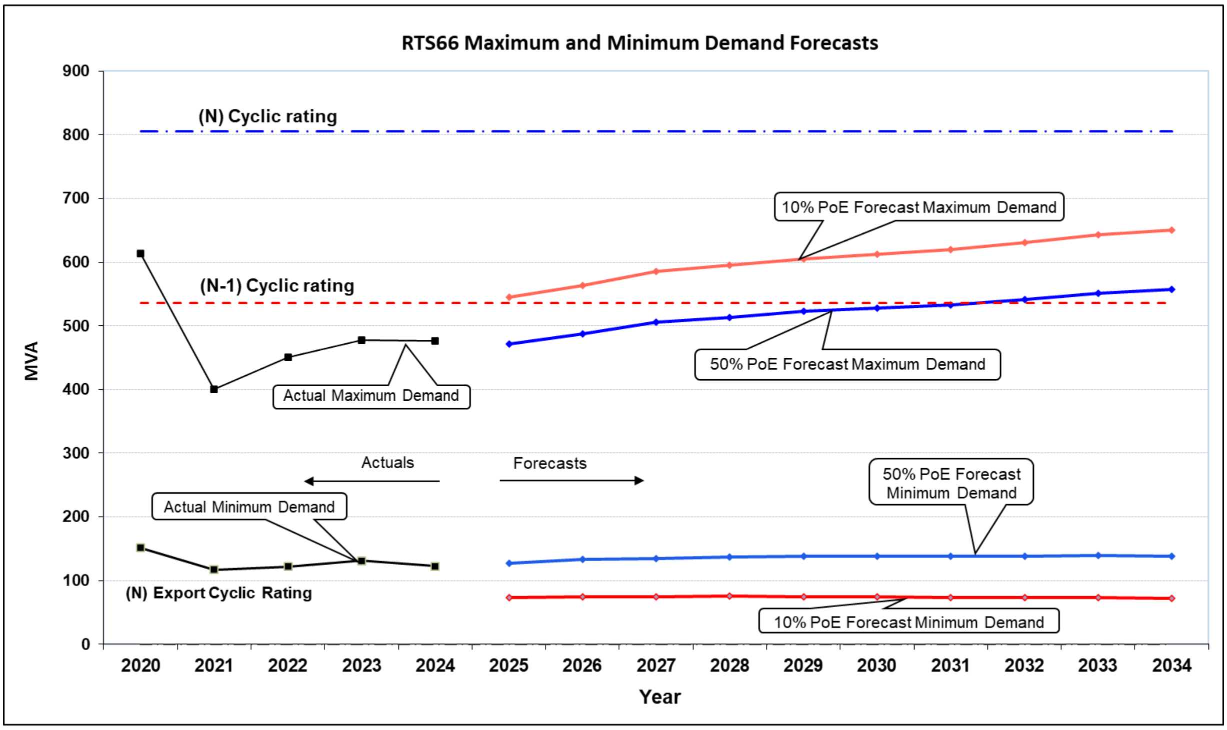
The following graph shows recent actual and forecast maximum and minimum demand at the station. The station's (N) and (N-1) import cyclic ratings at 35 degrees C are also shown. It should be noted that the ratings shown below are thermal ratings only. For some stations, export ratings (to accommodate 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:

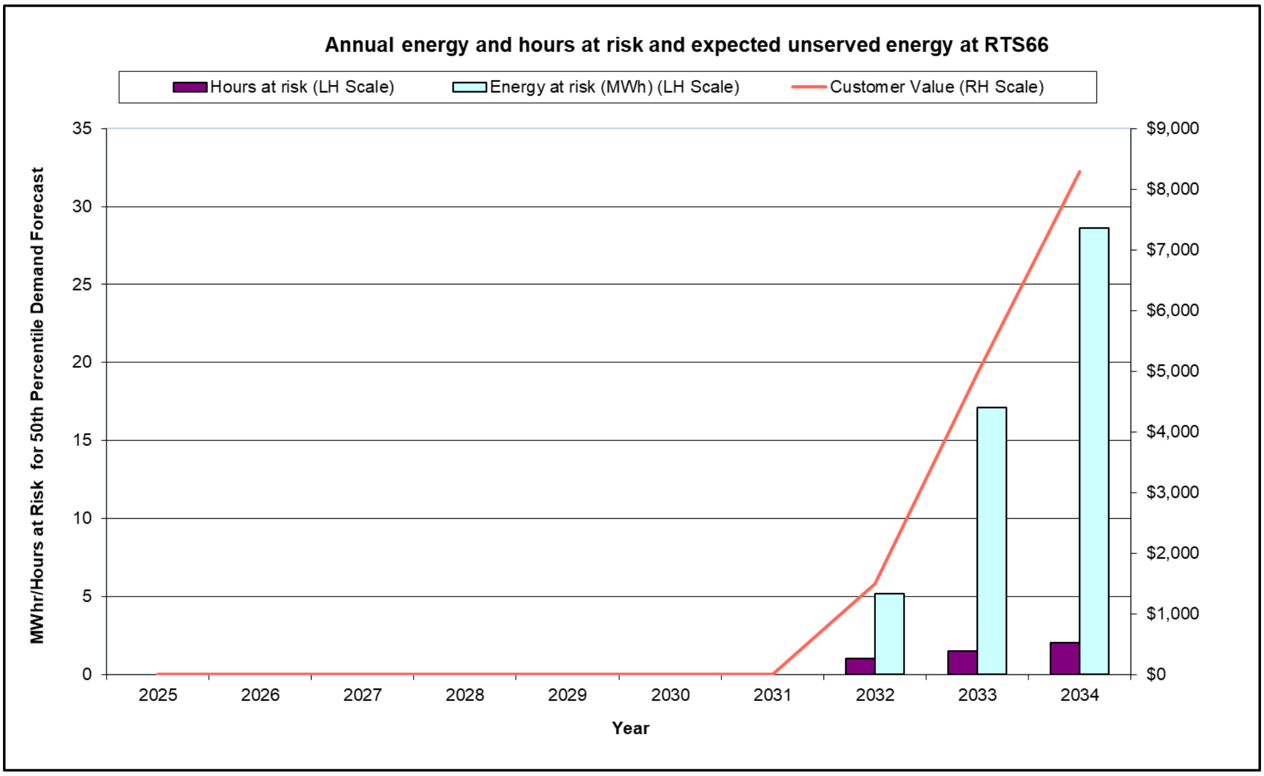
- For 15 hours per year, 95% of peak demand is expected to be reached in a 50th percentile summer.
- The station load power factor at time of peak demand is 0.97.

In relation to minimum demand, it is estimated that:

- For 46 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.



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.



Key statistics relating to energy at risk and expected unserved energy for 2034 under N-1 outage conditions are summarised in the table below. The VCR at RTS 66 kV is $44,623 per MWh.

	MWh	**Valued at VCR**
Energy at risk, at 50th percentile maximum demand forecast under N-1 outage condition	28.6	$1 million
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	0.19	$8,296
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	956	$43 million
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	6.2	$277,255
70/30 weighted expected unserved energy value (see below)	**2.0**	**$89,000**

Under the probabilistic planning approach[101], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[102]. 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)[103]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $89,000.

Possible Impact on Customers

System Normal Condition (Both transformers in service)

Applying the 50th percentile and 10th percentile maximum demand forecasts, there is sufficient import capacity at RTS66 to meet all demand when both transformers are in service.

N-1 System Condition

If one of the 225 MVA transformers at RTS66 is taken offline during times of maximum demand and the N-1 station import rating is exceeded, the OSSCA[104] automatic load shedding scheme which is operated by AusNet Transmission Group's TOC[105] 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

101 See section 3.1.

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

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

104 Overload Shedding Scheme of Connection Asset.

105 Transmission Operation Centre

load to the rated import capability of the station would be restored at zone substation feeder level in accordance with CitiPower'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. Install a fourth transformer at RTS 66kV. This option would involve the installation of 220 kV transformer 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 RTS 66 kV 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. Transfer some RTS 66 kV load to BTS 66 kV.

Preferred network option(s) for alleviation of constraints

On the basis of the present demand forecasts, the installation of an additional transformer and the 66 kV exit reconfiguration works at RTS 66 kV is unlikely to be economically justified in the forecast period. Prior to any augmentation of the import capacity at RTS 66 kV, any load at risk will be managed by load transfers to BTS 66 kV.

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.

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

Distribution Businesses supplied by this station: CitiPower (95%) and United Energy (5%)

	MVA	
Nameplate rating with all plant in service	805	via 3 transformers (summer)
Summer N-1 Station Import Rating:	536	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating:	536	
Summer N-1 Station Export Rating:	450	[See Note 7]
Winter N-1 Station Export Rating:	450	[See Note 7]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	471.3	487.9	506.1	513.4	522.6	528.0	533.2	541.7	551.1	557.3
50th percentile Winter Maximum Demand (MVA)	400.8	430.7	438.5	448.0	454.9	460.9	468.9	481.2	491.2	496.8
10th percentile Summer Maximum Demand (MVA)	545.0	563.9	585.7	595.5	605.3	612.5	619.8	630.7	643.2	650.7
10th percentile Winter Maximum Demand (MVA)	461.6	493.8	502.5	512.6	520.9	527.0	535.6	547.4	558.5	564.8
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	17.1	28.6
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.5	2.0
N-1 energy at risk at 10% percentile demand (MWh)	8.4	43.2	115.1	170.3	239.2	304.9	383.6	529.1	767.6	955.9
N-1 hours at risk at 10th percentile demand (hours)	1.0	2.5	4.5	6.5	7.5	9.5	11.0	16.0	24.5	31.5
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.11	0.19
Expected Unserved Energy at 10th percentile demand (MWh)	0.05	0.28	0.75	1.11	1.55	1.98	2.49	3.44	4.99	6.21
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	$0.01M
Expected Unserved Energy value at 10th percentile demand	$0.00M	$0.01M	$0.03M	$0.05M	$0.07M	$0.09M	$0.11M	$0.15M	$0.22M	$0.28M
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	$0.02M	$0.03M	$0.03M	$0.05M	$0.07M	$0.09M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	68.6	73.0	75.7	76.8	78.1	79.4	80.8	82.6	83.4	81.1
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 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 35 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. “Expected unserved energy” means “N-1 energy at risk” for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 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 16.6 MW of rooftop solar PV is installed on the AusNet distribution system and about 18.2 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.

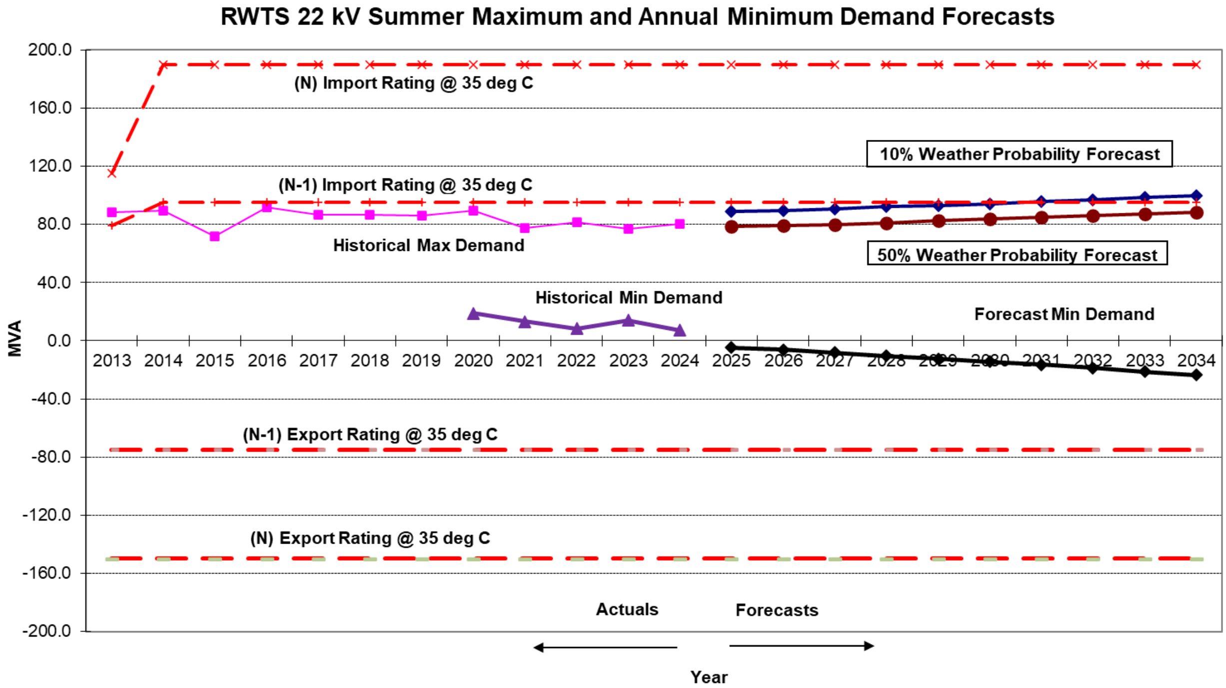
Magnitude, probability and impact of constraints

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 2023/24 summer maximum demand reached 80.1 MW (80.4 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 35°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 3 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 5.5 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.

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 2030/31.

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 2033/34 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	4	$0.19 million
Expected unserved energy at 10th percentile maximum demand	0.02	$831
70/30 weighted expected unserved energy value (see below)	**0.01**	**$249**

Under the probabilistic planning approach[106], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[107]. 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)[108]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2033/34 is $249.

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.

106 See section 3.1.

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

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

RINGWOOD TERMINAL STATION 22kV Loading (RWTS 22)
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	190 MVA via 2 transformers (Summer peaking)
Summer import N-1 Station Rating	95 MVA [See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating	95 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	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	78.6	79.2	80.0	81.2	82.4	83.5	84.6	85.9	87.3	88.5
50th percentile Winter Maximum Demand (MVA)	68.0	69.3	70.8	72.6	74.1	75.5	77.1	78.9	80.5	82.0
10th percentile Summer Maximum Demand (MVA)	88.6	89.7	90.8	92.1	93.1	94.3	95.5	96.9	98.5	99.8
10th percentile Winter Maximum Demand (MVA)	73.4	74.9	76.6	78.2	79.8	81.1	82.6	84.5	86.1	87.7
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)	0	0	0	0	0	0	0	1	2	4
N - 1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	1	1	2
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	0.0	0.0	0.0	0.02
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	$0.000249M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	-4.7	-6.1	-8.3	-10.6	-12.5	-14.4	-16.6	-18.8	-21.2	-23.5
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 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 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 2019 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.

RINGWOOD TERMINAL STATION 66 kV (RWTS 66 kV)

Ringwood Terminal Station is the main source of supply for a major part of the outer eastern metropolitan area. The geographic coverage of the station's supply area spans from Lilydale and Woori Yallock in the north east; to Croydon, Bayswater and Boronia in the east; and Box Hill, Nunawading and Ringwood to the west.

The electricity supply distribution networks for this region are the responsibility of both AusNet Electricity Services (73%) and United Energy (27%).

Embedded generation

About 171 MW of rooftop solar PV is installed on the AusNet distribution system and about 39.9 MW of rooftop solar PV is installed on the UE distribution system connected to RWTS 66 kV. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

A total of 6.2 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.

In March 2016 the B2 transformer at RWTS failed. It was replaced in August 2016 by one of the metropolitan spare transformers. AusNet Transmission Group also replaced the No. 4 220/66 kV transformer with a new 150 MVA unit in July 2018.

The existing four transformers are operated in two separate bus groups to limit the maximum fault currents on the 66 kV buses to 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 kept within the capabilities of their respective two transformers at all times otherwise load shedding may occur. For an unplanned transformer outage in any of the two RWTS bus groups, an auto close scheme will operate resulting in parallel operation of the three remaining transformers.

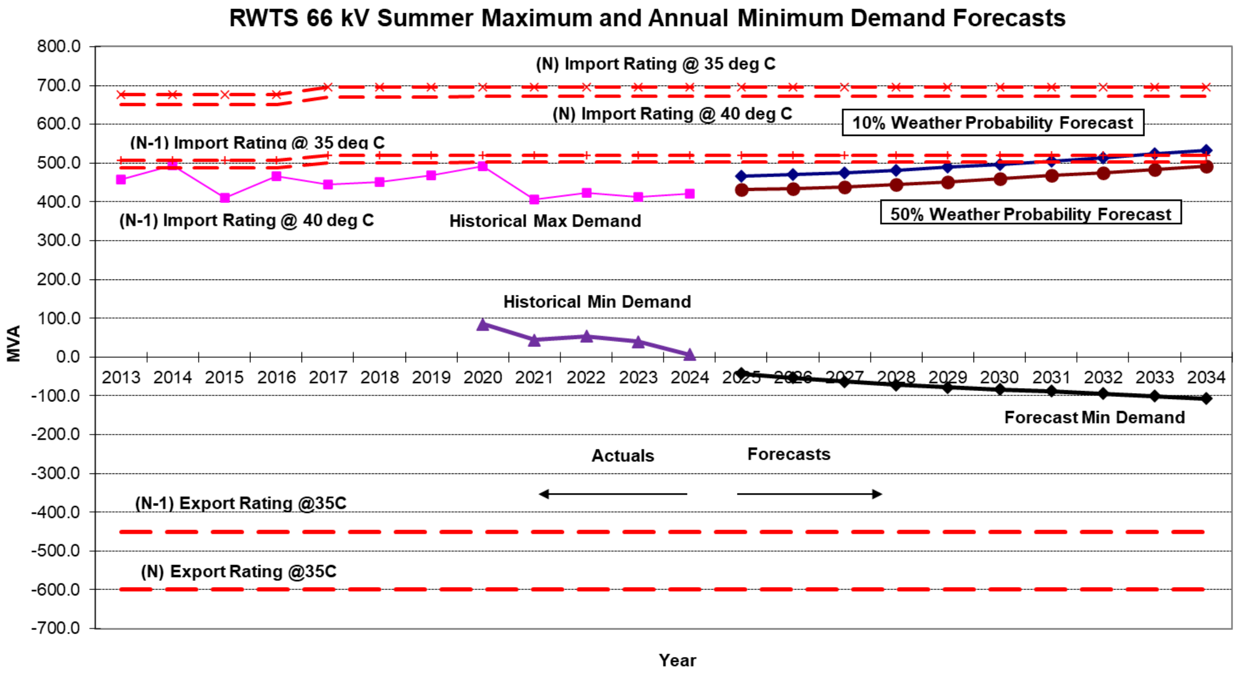
Combined Demand forecasts for RWTS 66 kV - Total Station Demand

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 2023/24 was 415.9 MW (421.1 MVA), which was lower than the summer 2008/09 station maximum demand.

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 35°C as well as 40°C ambient temperatures.

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.



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, however the 10th percentile summer maximum demand is expected to exceed the station's N-1 import rating from the summer of 2032/33.

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 0.99 at maximum demand but the load on the transformers has a power factor of 1 due to installed 66 kV capacitor banks. RWTS 66 kV demand is expected to exceed 95% of the 50th percentile peak demand for 7 hours per annum.

In relation to minimum demand, it is estimated that:

- For 17.5 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.88 at the time of minimum demand.

Key statistics relating to energy at risk and expected unserved energy for the year 2033/34 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	121	$5.1 million
Expected unserved energy at 10th percentile maximum demand	1.1	$44,937
70/30 weighted expected unserved energy value (see below)	**0.36**	**$13,481**

Under the probabilistic planning approach[109], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[110]. 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)[111]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2033/34 is $13,481.

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 on this bus group is forecast to remain within the 10th and 50th percentile demands. When required, such as if 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.

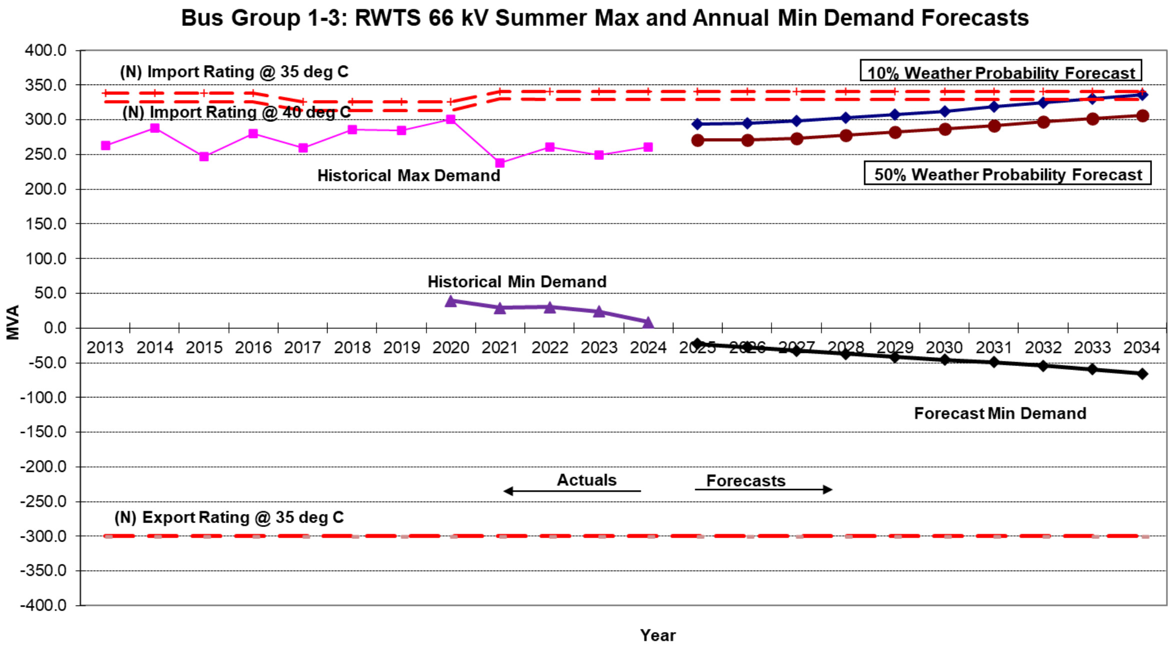
This bus group supplies United Energy's zone substations Nunawading (NW) and Box Hill (BH), and AusNet Electricity Services' zone substations Ringwood North (RWN), Lilydale (LDL), Chirnside Park (CPK) and Woori Yallock (WYK).

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 35°C and 40°C.

109 See section 3.1.

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

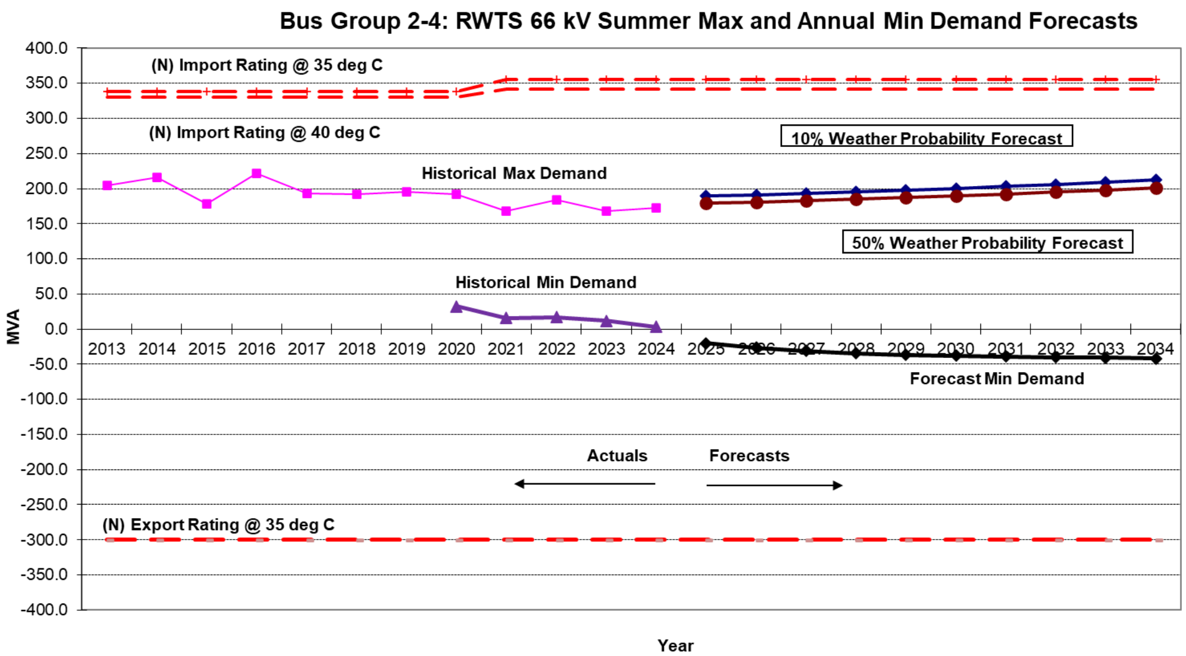
111 AEMO, *Victorian Electricity Planning Approach*, June 2016, page 12 (see Victorian-Electricity-Planning-Approach.ashx (aemo.com.au))



RWTS Bus group 2-4: Similar to 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 35°C and 40°C.



Based on the latest maximum demand forecast bus group No.1-3 has no pre-contingent energy at risk over the 10-year period.

For an outage of one 220/66 kV transformer at RWTS, the No. 1-3 and No. 2-4 bus groups will be tied and supplied by the three remaining in-service transformers. With a transformer out of service there will be sufficient capacity at the station to supply all demand at the 50^{th} percentile temperature for the ten-year forecast period. At the 10^{th} percentile temperature, for an outage of one 220/66 kV transformer at RWTS, there will be a minor amount of load at risk from 2031/32. 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.

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

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 (73%), United Energy (27%)
Normal import cyclic rating with all plant in service	696 MVA via 4 transformers (Summer peaking)
Summer import N-1 Station Rating (MVA):	520 MVA [See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating (MVA):	588 MVA
Normal export rating with all plant in service	600 MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	450 MVA [See Note 7 below for interpretation of Export rating]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	432.4	434.2	438.7	445.4	452.2	459.4	467.5	475.3	484.0	491.9
50th percentile Winter Maximum Demand (MVA)	353.2	361.7	372.5	382.5	392.6	402.8	413.5	424.6	435.1	444.3
10th percentile Summer Maximum Demand (MVA)	466.5	469.6	475.0	481.9	489.0	496.7	505.3	514.3	524.4	532.8
10th percentile Winter Maximum Demand (MVA)	371.6	380.4	390.9	401.5	412.0	422.6	433.7	445.3	456.5	465.9
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	17	60	121
N - 1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	0	4	6	9
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	0.0	0.1	0.5	1.1
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	$0.01M	$0.02M	$0.04M
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	$0.01M	$0.01M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	-42.6	-54.0	-63.6	-71.9	-78.1	-83.1	-88.2	-93.9	-100.4	-107.1
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 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 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 2019 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.

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 76,312 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 494.5 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
- 142 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
Girgarree Solar Farm	Approved project	Solar PV	75
Wunghnu Solar Farm	Approved project	Solar PV	76
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 Services is planning to replace two transformers (B2 and B3) at SHTS. The replacement project will be completed in 2026. During the replacement of a transformer the maximum reverse power flow for SHTS has to be limited to less than 225 MVA (pre-contingent) to avoid overloading the transformers should a transformer contingency occur during the planned transformer outage.

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 thermal ratings of some stations. SHTS is considered one such station and the station thermal ratings will be reviewed upon completion of the transformer replacement works.

Magnitude, probability and impact of constraints

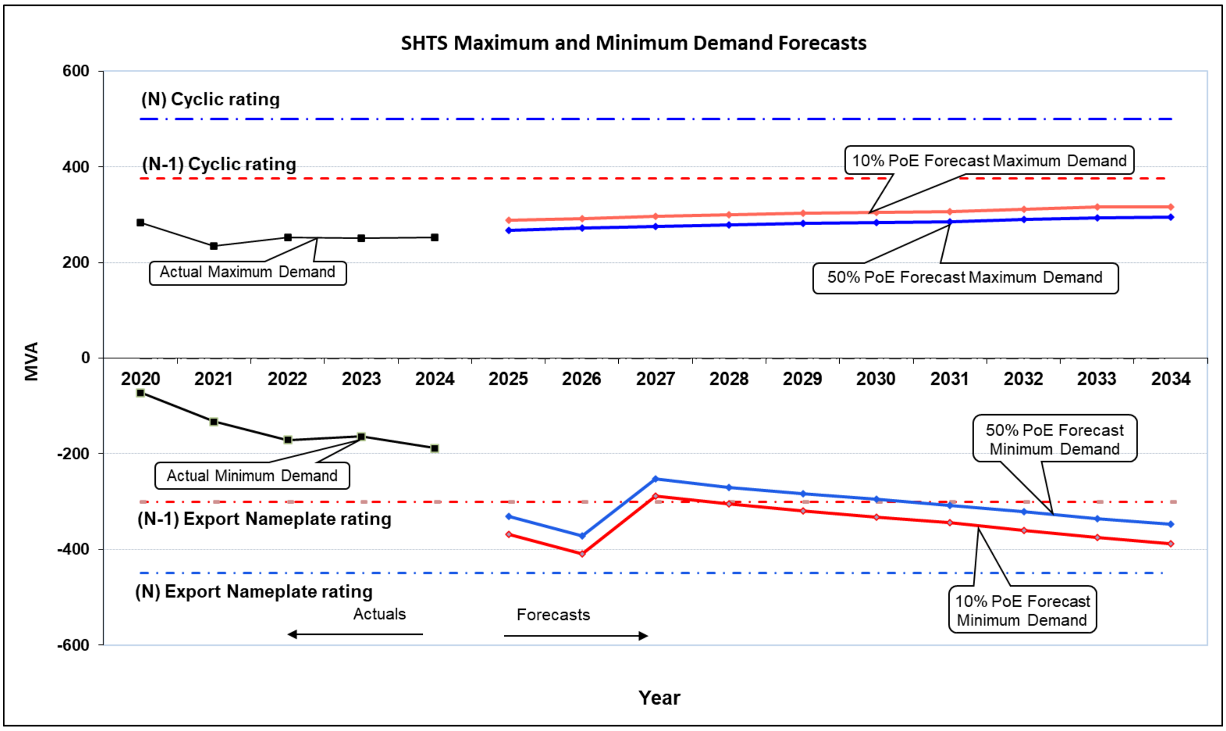
The following observations and risk assessment are based on actual readings of power flow at the Terminal Station Connection points. It therefore accounts for the present load and generation combination.

Maximum demand at SHTS occurs in summer. The maximum demand on the station reached 246.6 MW (252.3 MVA) in summer 2024. Due to the input of generation connected to the station, reverse power flows occur during low load periods. The minimum demand at SHTS reached -171.6 MW (-188.1 MVA) in October 2023.

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 35°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 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 0.91

The chart shows there is sufficient capacity at the station to meet all expected maximum demand at the 50th and 10th percentile temperature, over the forecast period even with one transformer out of service. Therefore, the need for augmentation or other corrective action 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 2034, approximately 87 MVA of embedded generation is at risk of curtailment for the loss of one transformer at SHTS. This equates to 517 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 3.4 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 (72%) and Jemena Electricity Networks (28%).

Maximum demand at SMTS 66 kV occurs in summer. In 2023/24 the summer maximum demand reached 384.9 MW (389.1 MVA), which is the historical maximum for the station.

Embedded generation

About 180 MW of rooftop solar PV is installed on the AusNet distribution system and about 68 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:

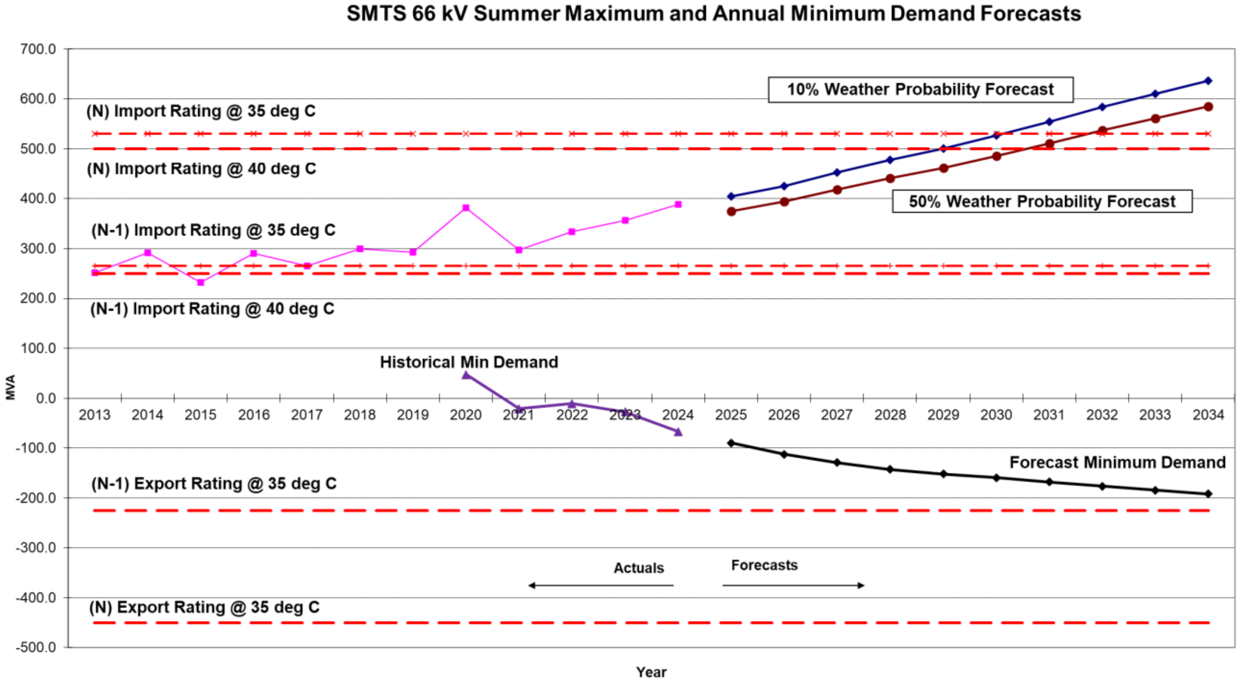
Site name	Status	Technology Type	Nameplate capacity (MW)
Somerton Power Station	Existing Plant	Gas	150
Cherry Tree Wind Farm	Existing Plant	Wind	57.5
Wollert Power Station	Existing Plant	Landfill Gas	7.7
Rubicon Power Station	Existing Plant	Hydro	14.6

Magnitude, probability and impact of constraints

The graph below depicts the 10th and 50th percentile maximum and minimum demand 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 35°C as well as 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.



The station load has a power factor of 0.99 at maximum demand. Demand is expected to exceed 95% of the 50th percentile peak demand for 4 hours per annum.

In relation to minimum demand, it is estimated that:

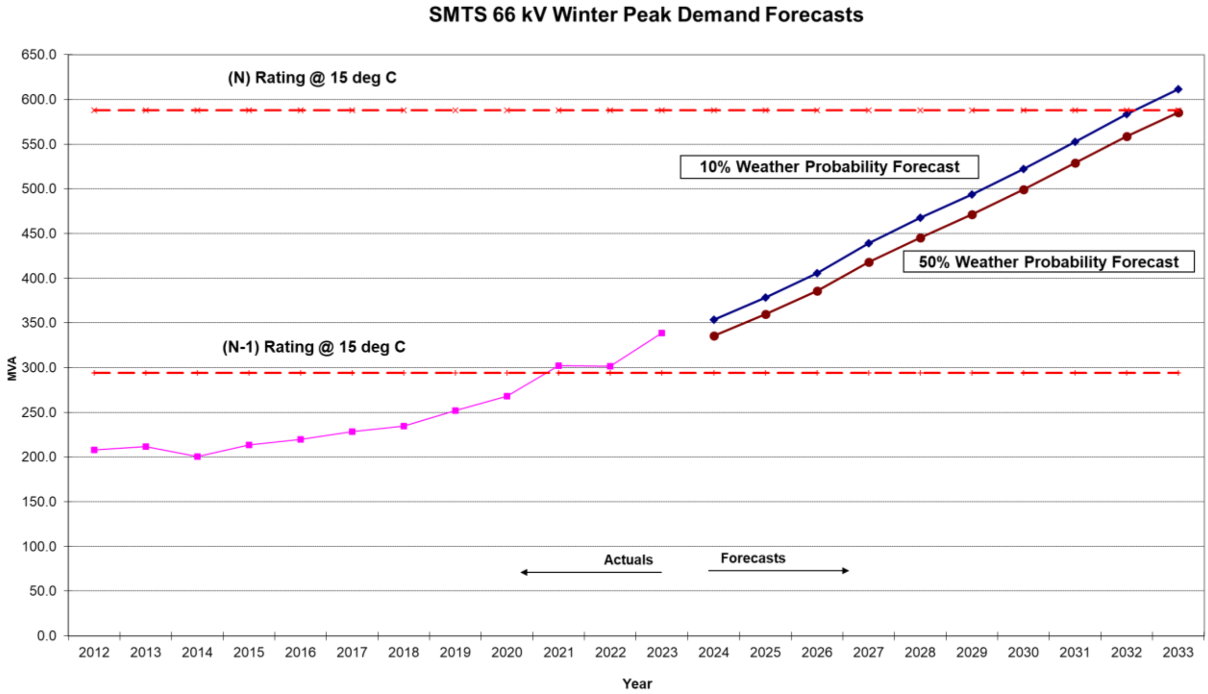
- For 54 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.94 at the time of minimum demand.

The "N" import rating on the above chart indicates the maximum demand that can be supplied from SMTS with both transformers in service.

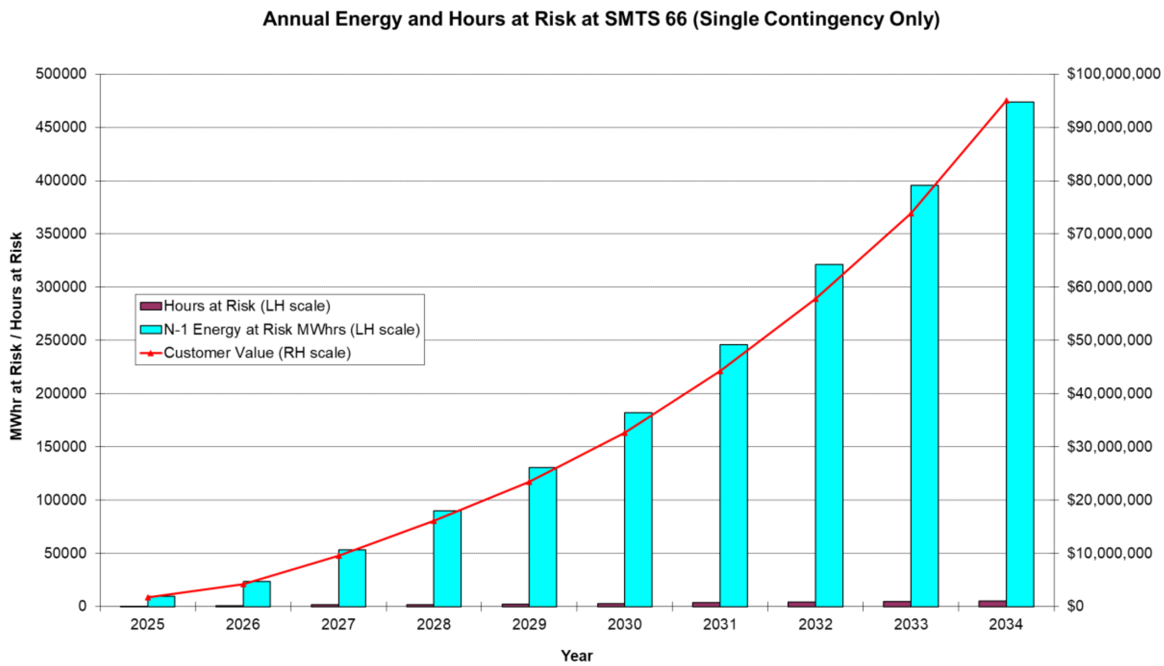
With the projected growth in customer demand in the area, it is expected that maximum demand at SMTS will continue to exceed its "N-1" import rating in summer at the 10th and 50th percentile temperatures, as shown in the graph above.

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.

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. SMTS exceeded its winter "N-1 " import rating this year and is expected to exceed its "N" import rating under 10th percentile winter maximum demand forecasts from winter 2032/33 but remain within its 50th percentile "N" rating for the 10-year planning horizon.



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-1" station import capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.



As already noted, 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 relating to energy at risk and expected unserved energy - assuming that Somerton Power Station is unavailable - for the year of 2025/26 under "N-1" outage conditions are summarised in the table below. The VCR at SMTS is $41,449 per MWh.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	23,502	$974 million
Expected unserved energy at 50th percentile maximum demand	104	$4.3 million
Energy at risk, at 10th percentile demand maximum forecast	43,279	$1794 million
Expected unserved energy at 10th percentile maximum demand	191	$7.9 million
70/30 weighted expected unserved energy value (see below)	**130**	**$5.4 million**

Under the probabilistic planning approach[112], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[113]. 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)[114]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2025/26 is $5.4 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[115] to protect the connection assets from overloading[116], 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, affecting approximately 44,600 customers in 2024/25. 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.

112 See section 3.1.

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

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

115 Transmission Operation Centre.

116 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.

Comments on Energy at Risk assuming Somerton Power Station is available

The previous comments on energy at risk are based on the assumption that there is no embedded generation available to offset the 220/66 kV transformer loading. The Somerton Power Station (SPS) is capable of generating up to 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. If SPS is generating to its full capacity there would be significantly reduced energy at risk at SMTS over the ten year planning horizon for the 10th percentile summer maximum demand forecast.

Feasible options for alleviation of constraints

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

1. Implement contingency plans to transfer load to adjacent terminal stations. AusNet Electricity Services has established and implemented the necessary plans that enable up to 23 MVA of load transfers via existing 22 kV feeders to adjoining zone substations. Jemena has plans and the capability to transfer an additional 12.6 MVA. This option is able to partly reduce the interruption duration and load at risk resulting from a major transformer failure.

2. Install a third 225 MVA 220/66 kV transformer at South Morang Terminal Station (SMTS), which would also require the installation of fault limiting reactors.

3. Demand Management. AusNet Electricity Services is currently using an MVA tariff to encourage large customers to improve their power factor as well as a critical peak pricing tariff to encourage them to reduce load at peak demand times and thus reduce the station loading. Up to 50% of the maximum demand at SMTS 66 kV is expected to be summer residential load, consisting largely of air conditioning load. With the existing load mix it is likely that demand reduction initiatives can play a limited role in reducing the peak summer load at SMTS 66 kV.

4. Embedded Generation. As mentioned above, the Somerton power station is connected to SMTS. A network support agreement with SPS or other 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. In the event that there are no firm commitments by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce future load at SMTS 66 kV to alleviate import constraints, it will be proposed to install a new third 220/66 kV transformer at SMTS 66 kV. The capital cost of this option is estimated at $43.6 million, which includes the cost of installing two fault limiting reactors. This equates to a total annual cost of approximately $3.4 million per annum. Under the latest demand forecast, the installation of the third transformer at SMTS may be economically justified by 2026. AusNet Services and Jemena plan to commence a RIT-T for SMTS in 2024/25.

2. Implement the following temporary measures to cater for an unplanned outage of one transformer at SMTS under critical loading conditions until the new 220/66 kV transformer is commissioned:

- maintain contingency plans to transfer load quickly to adjacent terminal stations;
- rely on Somerton Power Station (SPS) generation to reduce loading at SMTS 66 kV, and investigate the option of formalising a network support agreement with SPS; 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 (72%) Jemena Electricity Networks (28%)

Normal cyclic rating with all plant in service	530	MVA via 2 transformers (Summer peaking)
Summer N-1 Station Rating	265	MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating	294	MVA
Normal export rating with all plant in service	450	MVA [See Note 7 below for interpretation of Export rating]
Export N-1 Station Rating	225	MVA [See Note 7 below for interpretation of Export rating]

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	375.0	393.8	418.1	440.6	461.4	485.1	510.6	537.2	561.4	585.1
50th percentile Winter Maximum Demand (MVA)	359.6	385.8	418.0	445.5	471.4	499.2	528.8	558.7	585.5	611.8
10th percentile Summer Maximum Demand (MVA)	404.9	425.5	452.7	477.8	500.8	526.7	554.5	583.3	610.3	636.2
10th percentile Winter Maximum Demand (MVA)	378.7	405.8	439.0	467.5	493.9	522.2	552.7	583.6	611.3	638.6
N - 1 energy at risk at 50th percentile demand (MWh)	9,887	23,502	53,465	89,703	130,630	182,053	246,222	321,045	395,658	473,893
N - 1 hours at risk at 50th percentile demand (hours)	474	933	1,564	2,012	2,439	2,909	3,557	4,166	4,637	5,008
N - 1 energy at risk at 10th percentile demand (MWh)	20,883	43,279	84,842	131,156	181,227	243,276	317,941	401,742	483,103	566,759
N - 1 hours at risk at 10th percentile demand (hours)	840	1,396	2,028	2,533	2,987	3,497	3,989	4,452	4,803	5,112
Expected Unserved Energy at 50th percentile demand (MWh)	44	104	236	396	577	804	1,087	1,418	1,747	2,093
Expected Unserved Energy at 10th percentile demand (MWh)	92	191	375	579	800	1,074	1,404	1,774	2,134	2,503
Expected Unserved Energy value at 50th percentile demand	$1.81M	$4.30M	$9.79M	$16.42M	$23.91M	$33.33M	$45.07M	$58.77M	$72.43M	$86.75M
Expected Unserved Energy value at 10th percentile demand	$3.82M	$7.92M	$15.53M	$24.01M	$33.18M	$44.54M	$58.20M	$73.54M	$88.44M	$103.75M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$2.41M	$5.39M	$11.51M	$18.70M	$26.69M	$36.69M	$49.01M	$63.20M	$77.23M	$91.85M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum demand (MVA)	-89.9	-112.3	-129.2	-142.8	-152.0	-159.5	-168.3	-176.3	-184.6	-192.1
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

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The summer rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.65 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 sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50th and 10th percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx)
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 located in the south-east of greater Melbourne. The geographic coverage of the station's supply area spans from Blackburn in the north to Noble Park in the south and from Wantirna South in the east to Riversdale in the west. The electricity supply network for this large region is split between United Energy (UE) and CitiPower (CP).

Embedded generation

A total of 198 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to SVTS. It consists of:

- 167.6 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 & No.2 transformers (B1 & B2) are operated in parallel as one group (SVTS 1266) and supply the No.1 & No.2 buses. The No.3 & No.4 transformers (B3 & B4) are operated in parallel as a separate group (SVTS 3466) and supply the No.3 & No.4 buses. Connection between No.1 & No.4 buses is maintained via transfer buses No.5 & No.6. The 66 kV bus 2-3 and bus 4-5 tie circuit breakers are operated normally open to limit the fault levels on the 66 kV buses to within switchgear ratings. For an unplanned outage of any one of the four transformers, 66 kV bus 2-3 and bus 4-5 tie circuit breakers will close automatically and maintain the station in a 3-transformer closed loop arrangement. Given this configuration, the demand on the station will therefore need to be controlled as follows:

- Load demand on the SVTS 1266 group should be kept within the import capabilities of the two transformers B1 & B2 at all times.
- Load demand on the SVTS 3466 group should be kept within the import capabilities of the two transformers B3 & 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.

SVTS 66 kV is a summer critical terminal station. The maximum demand in summer 2024 was 384.2 MW (392.2 MVA). This was 47.6 MW higher than the maximum demand recorded in summer 2023.

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

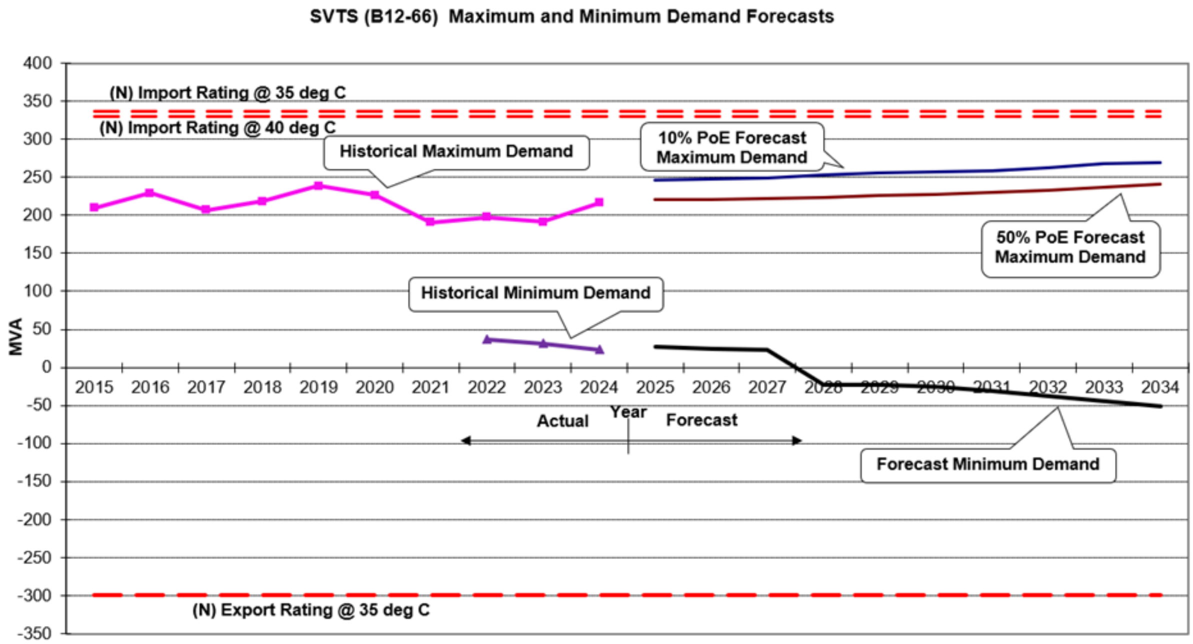
Transformer group SVTS 1266 (B12): Summer maximum demand forecasts

This bus group supplies Noble Park, Springvale South, Clarinda, Oakleigh East, Springvale, and Springvale West zone substations owned by United Energy. Four embedded generation sites over 1 MW with a total capacity of 25.8 MW are connected at SVTS 1266 (B12) bus group.

The maximum demand in summer 2024 for the SVTS 1266 group was 209.9 MW (216.2 MVA).

The graph below shows the 10th and 50th percentile maximum and minimum demand forecasts for SVTS 1266 and the corresponding import and export ratings at 35°C as well as 40°C ambient temperature with both transformers in service.

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 bus group.

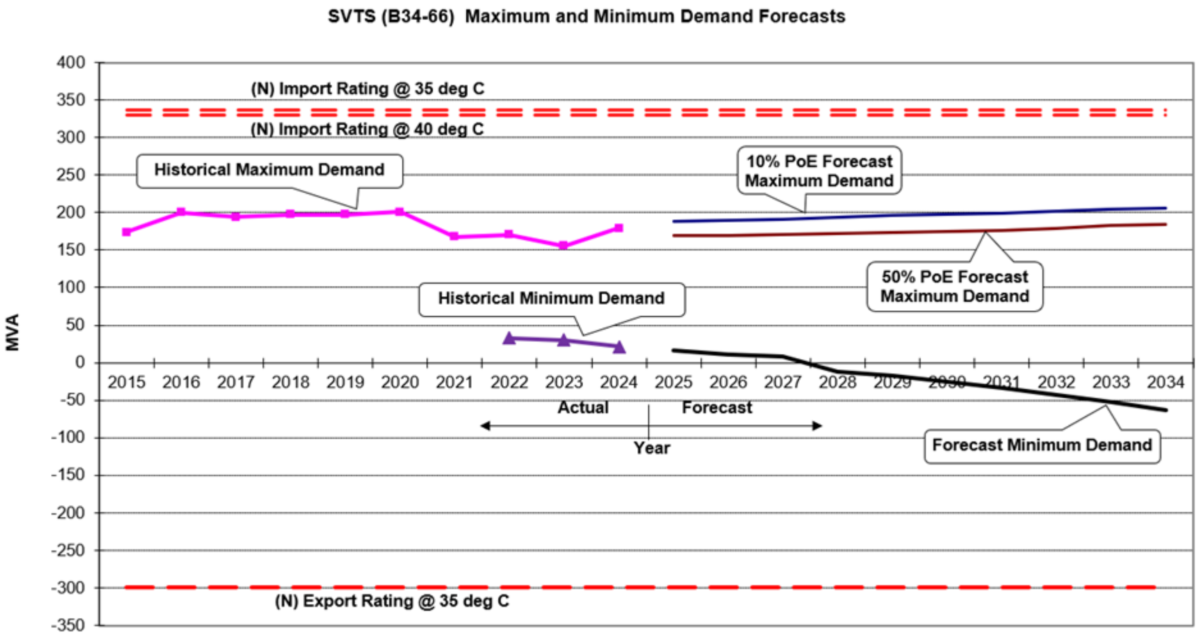
The graph above shows that with both transformers in service, there is adequate import/export capacity to meet the anticipated maximum/minimum demand for the entire planning period.

Transformer group SVTS 3466 (B34): 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 2024 for the SVTS 3466 group was 177.1 MW (179.4 MVA).

The graph below depicts the 10th and 50th percentile maximum and minimum demand forecasts for SVTS3466 and the corresponding import and export ratings at 35°C as well as 40°C ambient temperature with both transformers in 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 bus group.

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.

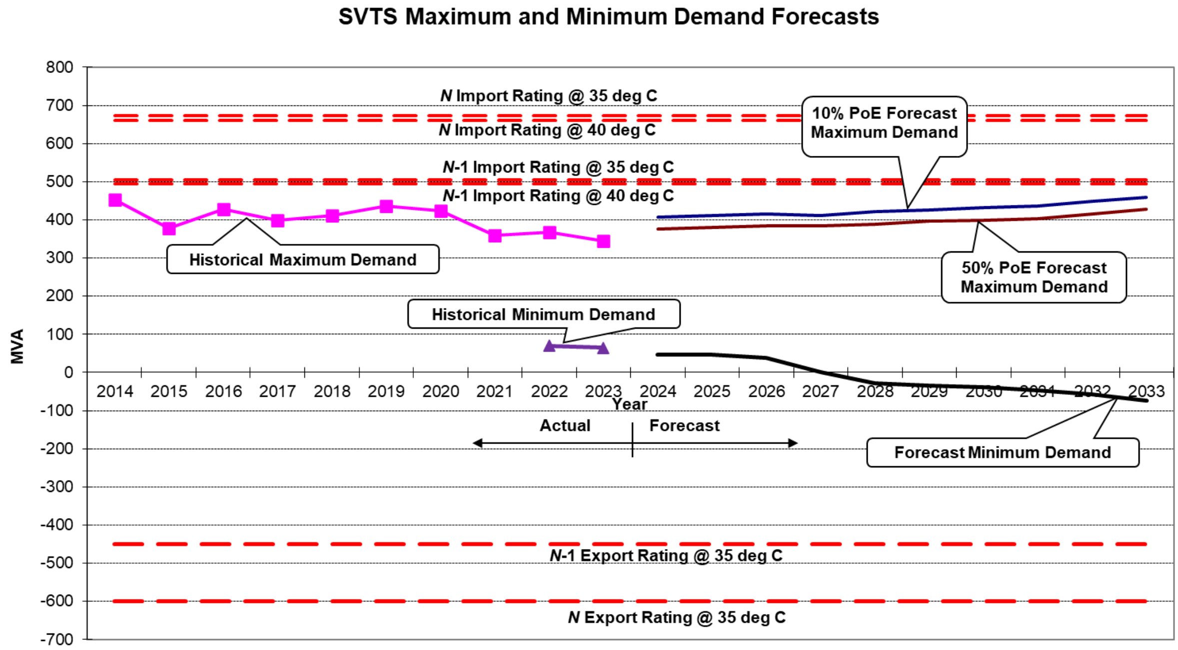
SVTS total demand forecasts

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 35°C as well as 40°C ambient temperature.

If one of the 220/66 kV transformers at SVTS is taken offline during times of maximum demand and the (N-1) station import rating is exceeded, the OSSCA[117] load shedding scheme, which is operated by AusNet Transmission Group's NOC[118], 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 CitiPower's operational procedures after the operation of the OSSCA scheme.

117 Overload Shedding Scheme of Connection Asset.

118 Network Operations Centre.



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 meet by SVTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

There is approximately 50 MVA of load transfer available at SVTS 66 kV for summer 2024/25.

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 35°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.

The station load is forecast to have a power factor of 0.99 at times of peak demand. The demand at SVTS is expected to exceed 95% peak demand for approximately 28 hour per annum.

The station load is forecast to have a power factor of 0.79 at times of minimum demand. The demand at SVTS is expected to reach 95% minimum demand for approximately 1 hour per annum.

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

SPRINGVALE TERMINAL STATION 66 kV

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

Distribution Businesses supplied by this station: United Energy (95%) and CitiPower (5%)
Station operational rating (N elements in service): 672 MVA via 4 transformers (Summer peaking)
Summer N-1 Station Import Rating: 504 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 562 MVA
Summer N-1 Station Export Rating: 450 MVA [See Note 7]
Winter N-1 Station Export Rating: 450 MVA [See Note 7]

Station: SVTS 66kV import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	387	387	389	393	396	399	403	408	416	421
50th percentile Winter Maximum Demand (MVA)	327	329	333	337	340	343	347	353	358	361
10th percentile Summer Maximum Demand (MVA)	431	434	437	443	447	450	453	459	467	469
10th percentile Winter Maximum Demand (MVA)	349	351	356	360	364	365	369	376	380	385
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	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	0.0	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	0.0	0.0	0.0	0.0
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value at 10th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Hours per year that 95% of maximum demand is expected to be reached	28	30	31	31	31	31	31	31	31	28
Station load power factor at the time of maximum demand	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98

Station: SVTS 66kV export	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
10th percentile minimum demand (MVA)	41	35	30	-33	-39	-49	-63	-79	-96	-113
Maximum generation at risk under N-1 (MVA)	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

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.65 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 2019 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.
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.

TEMPLESTOWE TERMINAL STATION (TSTS)

TSTS consists of three 150 MVA 220/66 kV transformers, and it is the main source of supply for a major part of the north-eastern metropolitan area. The geographic coverage of the supply area spans from Eltham in the north to Canterbury in the south, and from Donvale in the east to Kew in the west. The electricity supply network for this large region is split between United Energy, CitiPower, AusNet Electricity Services, and Jemena Electricity Networks.

Embedded generation

A total of 125.4 of embedded generation capacity is installed on the distribution system connected to TSTS, including:

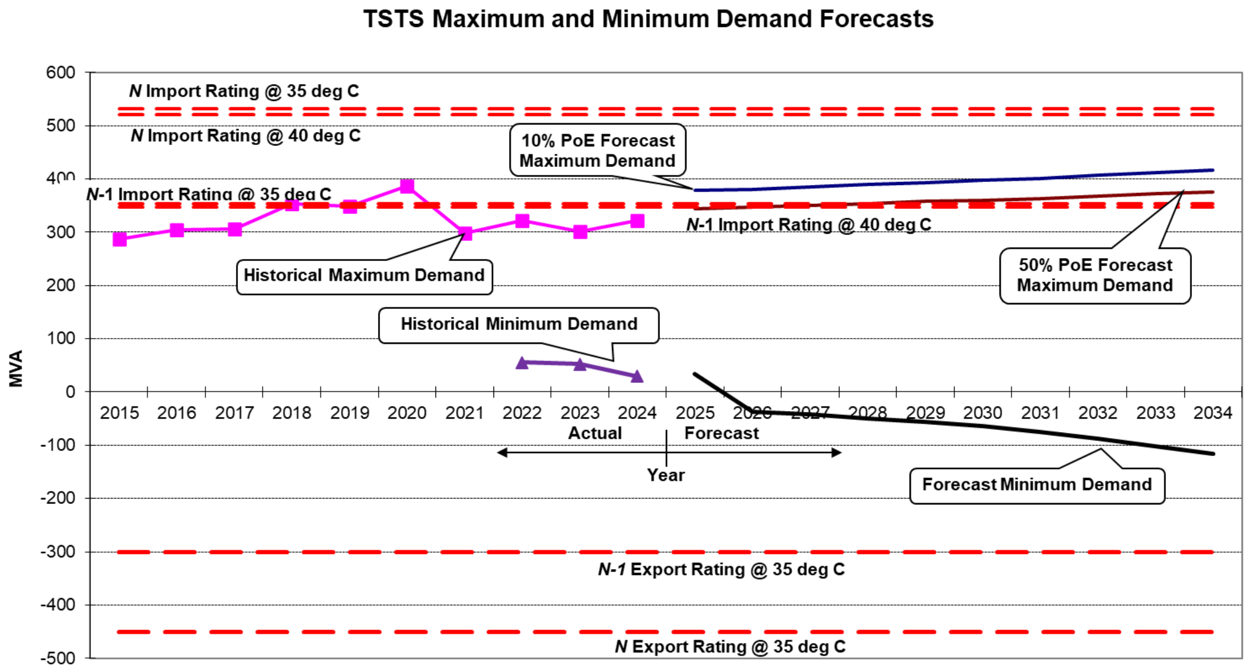
- About 123.9 MW of rooftop solar PV is installed within the distribution system connected to TSTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW.

- 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 314 MW (321.7 MVA) in summer 2024. This is 19.8 MW higher than the maximum demand recorded in summer 2023.

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 35°C as well as 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.

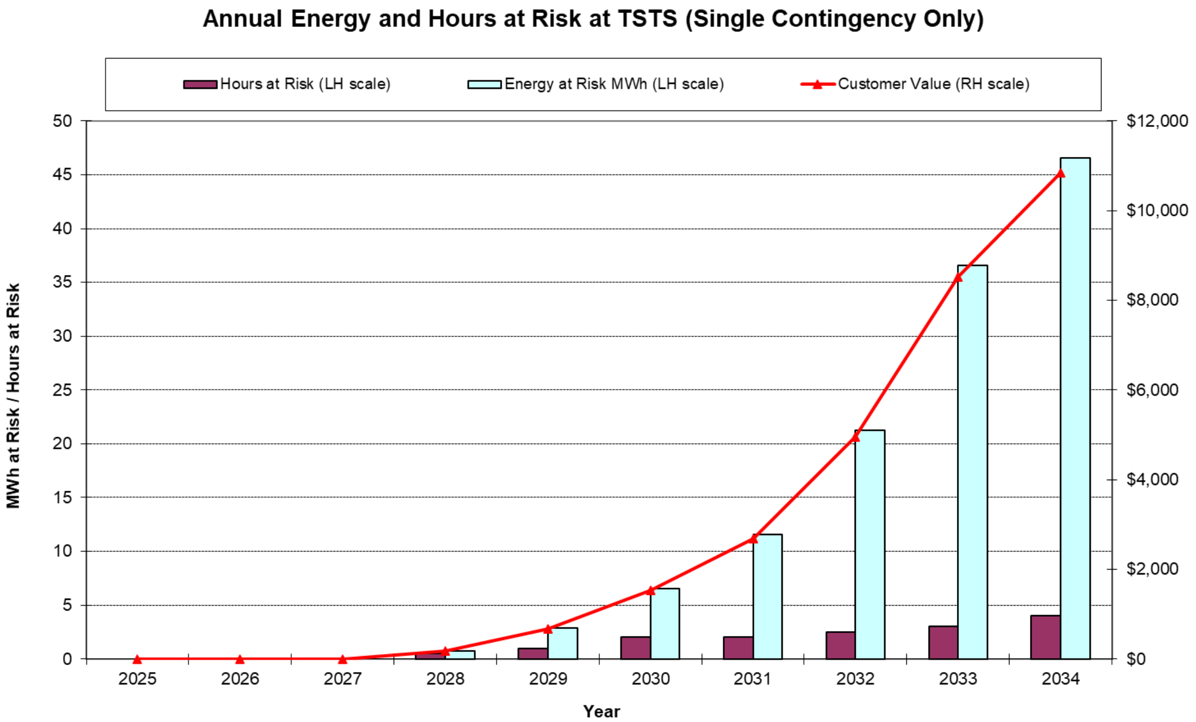
The export ratings on the chart reflect thermal ratings as advised by the asset owner. For some stations, the effective export ratings may be further limited once specific details of proposed embedded generator connection(s) are known. The actual availability of export capacity (which may be lower than 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 demand is forecast to exceed the station's (N-1) import rating at 35°C and 40°C from summer 2026 and summer 2031 respectively.

The station load is forecast to have a power factor of 0.97 at times of peak demand. The demand at TSTS is expected to exceed 95% peak demand for approximately 3 hours per annum.

The station load is forecast to have a power factor of 0.26 at times of minimum demand. The demand at TSTS is expected to reach 95% minimum demand for approximately 3 hours per annum.



Key statistics relating to energy at risk and expected unserved energy for 2034 under N-1 outage conditions are summarised in the table below. The VCR for TSTS is $35,409 per MWh.

	MWh	Valued at VCR
Energy at risk, at 50^{th} percentile demand forecast	47	$1.65 million
Expected unserved energy at 50^{th} percentile demand	0.3	$10,854
Energy at risk, at 10^{th} percentile demand forecast	533	$18.8 million
Expected unserved energy at 10^{th} percentile demand	3.5	$124,274
70/30 weighted expected unserved energy value (see below)	**1.3**	**$44,880**

AusNet Transmission Group indicated that two of the three transformers at TSTS have failure rates that are above average due to their condition. Therefore, the expected unserved energy calculated above may under-estimate the risk at this station. 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 with the earliest delivery timing in 2026. The transformers will be replaced with 150 MVA transformers with no expected change to the station ratings. Given that AusNet Transmission Group plans to replace these transformers as part of its asset replacement program, the elevated failure rates are unlikely to advance any augmentation works at this terminal station.[119]

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 4.6) 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 10^{th} and 50^{th} 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 50^{th} and 10^{th} percentile expected unserved energy estimates (respectively)[122]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2034 is $44,880.

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[123] load shedding scheme which is operated by AusNet Transmission Group's TOC[124] 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

119 See link below for more details on Templestowe Terminal Station RIT-T:
https://www.ausnetservices.com/en/About/Projects-and-Innovation/Regulatory-Investment-Test

120 See section 3.1.

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.

124 Transmission Operations Centre.

accordance with each distribution company'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 import constraint:

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy, CitiPower, AusNet Electricity Services and Jemena Electricity Networks have established and implemented the necessary plans that enable load transfers under contingency conditions. These plans are reviewed annually prior to the summer season. The total transfer capability away from TSTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 53 MVA for summer 2024-25.

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 tables on the following pages provide 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 Electricity Services (20%), Jemena (8%)
Station operational rating (N elements in service): 531 MVA via 3 transformers (Summer peaking)
Summer N-1 Station Import Rating: 353 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Import Rating: 391 MVA
Summer N-1 Station Export Rating: 300 MVA [See Note 7]
Winter N-1 Station Export Rating: 300 MVA [See Note 7]

Station: TSTS 66kV import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	344	347	350	354	358	360	363	367	373	376
50th percentile Winter Maximum Demand (MVA)	259	263	268	272	276	279	283	289	294	297
10th percentile Summer Maximum Demand (MVA)	379	381	384	389	394	397	401	407	412	416
10th percentile Winter Maximum Demand (MVA)	277	281	285	291	295	298	302	307	313	317
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	1	3	7	12	21	37	47
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	1	1	2	2	3	3	4
N-1 energy at risk at 10th percentile demand (MWh)	88	100	121	155	193	227	274	349	454	533
N-1 hours at risk at 10th percentile demand (hours)	7	7	8	9	11	12	15	18	24	26
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3
Expected Unserved Energy at 10th percentile demand (MWh)	0.6	0.7	0.8	1.0	1.3	1.5	1.8	2.3	3.0	3.5
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.2k	$0.7k	$1.5k	$2.7k	$5.0k	$8.5k	$10.9k
Expected Unserved Energy value at 10th percentile demand	$20.4k	$23.2k	$28.1k	$36.2k	$45.0k	$52.9k	$63.8k	$81.3k	$105.9k	$124.3k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	$6.1k	$7.0k	$8.4k	$11.0k	$14.0k	$16.9k	$21.0k	$27.9k	$37.7k	$44.9k
Hours per year that 95% of maximum demand is expected to be reached	3	3	3	3	3	3	3	3	3	3
Station load power factor at the time of maximum demand	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96

Station: TSTS 66kV export	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
10th percentile minimum demand (MVA)	34	-37	-43	-49	-56	-64	-75	-87	-102	-117
Maximum generation at risk under N-1 (MVA)	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

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. For 50th percentile value, the rating is at an ambient temperature of 35 degrees Centigrade. For 10th percentile value, the rating is at an ambient temperature of 40 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.65 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 2019 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.
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 64,342 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 417 MW of embedded generation capacity is installed on the Powercor sub-transmission and distribution systems connected to TGTS. It consists of:

- 346 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[125]	Existing Plant	Wind turbine	138
Woolsthorpe Wind Farm	Proposed	Wind turbine	72

Magnitude, probability and impact of constraints

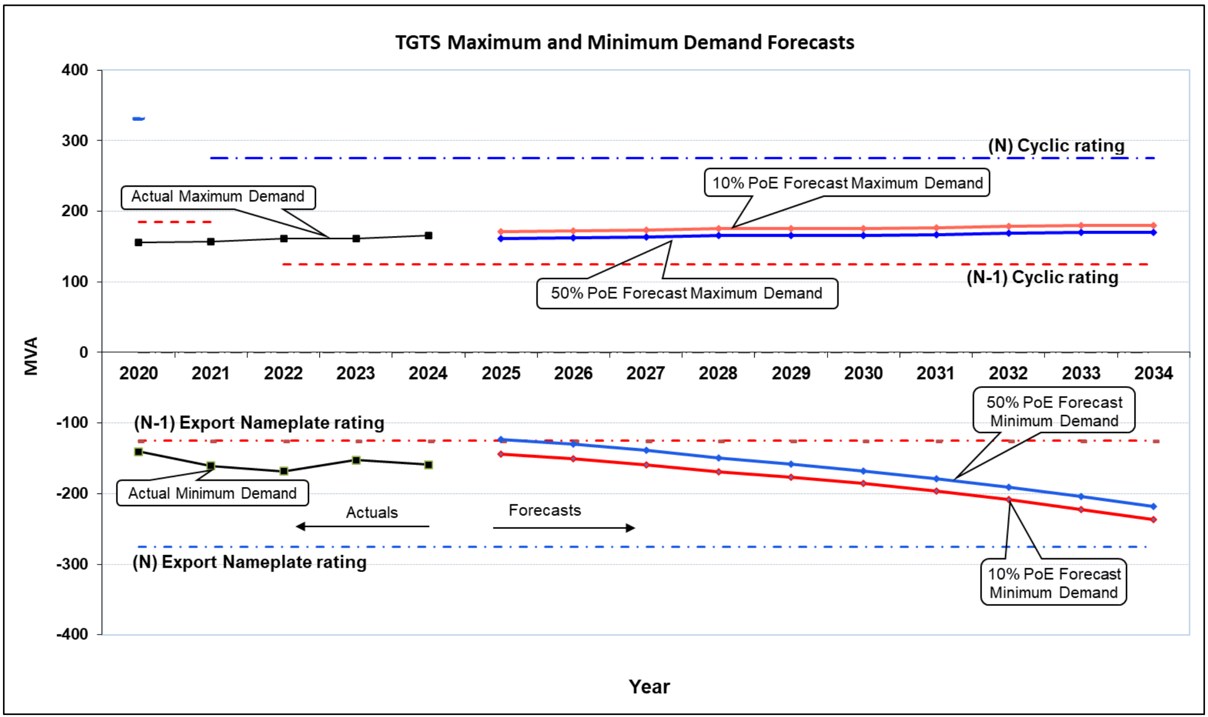
TGTS maximum demand for the past 5 years has been winter peaking but peaks can occur in summer or spring (depending upon the dairy industry load and the impact of wind farms connected to the 66 kV network).

The graph below shows:

[125] 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 35°C ambient temperature;
- actual station maximum demand reached 164.57 MW (166 MVA) in winter 2023; and
- actual minimum demand reached -127.1 MW (-158.8 MVA) in October 2023.

The graph also shows a reduction in the station rating of TGTS from cyclic to nameplate in 2021. As explained in section 4.2 of this report, the connection of significant embedded generation to networks supplied from some terminal stations has led to reverse power flows that necessitate a reduction in the ratings of some stations, including TGTS.



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.

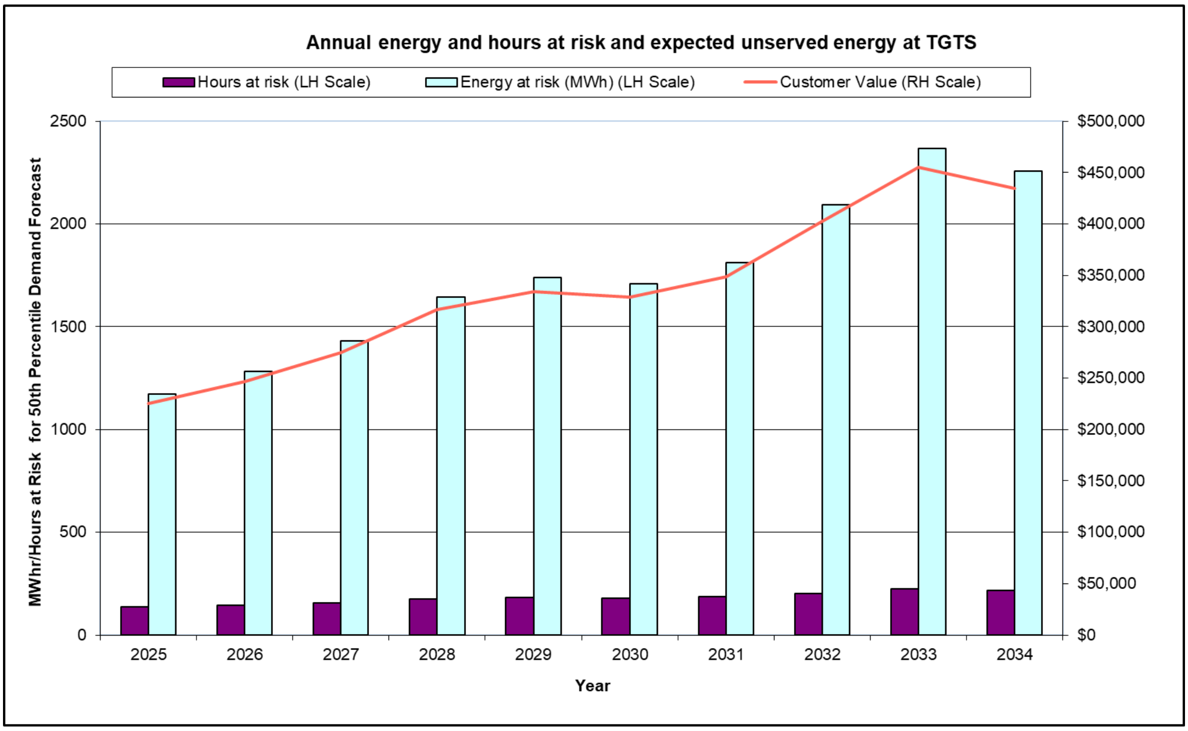
In relation to minimum demand, it is estimated that:

- For 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 0.80.

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 $41,443 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 2034 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at VCR
Energy at risk, at 50th percentile maximum demand forecast	2,258	$100 million
Expected unserved energy at 50th percentile maximum demand	9.79	$0.4 million
Energy at risk, at 10th percentile maximum demand forecast	5,136	$228 million
Expected unserved energy at 10th percentile maximum demand	22.26	$1 million
70/30 weighted expected unserved energy value (see below)	**13.5**	**$0.6 million**

Under the probabilistic planning approach[126], the cost of energy at risk is weighted by the expected unavailability per transformer per annum (0.221%, as explained in section 4.6) to determine the expected unserved energy cost in a year due to a major transformer outage[127]. 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)[128]. 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 2034, 112 MVA of embedded generation is at risk of curtailment for the loss of one transformer at TGTS. This equates to 1,078 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 5 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).

126 See section 3.1.

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

128 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) by the use of the 66 kV tie lines between TGTS and GTS in the event of an unplanned outage of one transformer at TGTS under critical loading conditions. This load transfer is in the order of 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	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	154.8	154.6	155.5	156.3	157.1	156.9	156.9	157.9	159.3	159.0
50th percentile Winter Maximum Demand (MVA)	161.1	162.4	163.7	165.5	166.1	165.9	166.8	168.8	170.4	169.7
10th percentile Summer Maximum Demand (MVA)	170.1	169.6	170.5	171.6	172.5	172.3	172.2	173.3	175.0	174.8
10th percentile Winter Maximum Demand (MVA)	170.8	172.1	173.5	175.3	175.7	175.6	176.6	178.9	180.3	179.6
N-1 energy at risk at 50% percentile demand (MWh)	1173.3	1282.6	1429.8	1645.3	1738.0	1708.3	1812.6	2092.9	2368.2	2258.4
N-1 hours at risk at 50th percentile demand (hours)	138.0	144.5	156.8	174.0	181.0	178.5	185.8	202.8	224.8	217.5
N-1 energy at risk at 10% percentile demand (MWh)	3188.2	3324.8	3616.7	4016.4	4176.2	4143.4	4291.0	4830.0	5306.8	5136.4
N-1 hours at risk at 10th percentile demand (hours)	287.5	294.8	310.5	334.0	345.5	343.3	350.5	381.8	405.0	398.8
Expected Unserved Energy at 50th percentile demand (MWh)	5.08	5.56	6.20	7.13	7.53	7.40	7.85	9.07	10.26	9.79
Expected Unserved Energy at 10th percentile demand (MWh)	13.82	14.41	15.67	17.40	18.10	17.95	18.59	20.93	23.00	22.26
Expected Unserved Energy value at 50th percentile demand	$0.23M	$0.25M	$0.27M	$0.32M	$0.33M	$0.33M	$0.35M	$0.40M	$0.46M	$0.43M
Expected Unserved Energy value at 10th percentile demand	$0.61M	$0.64M	$0.70M	$0.77M	$0.80M	$0.80M	$0.83M	$0.93M	$1.02M	$0.99M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.34M	$0.36M	$0.40M	$0.45M	$0.47M	$0.47M	$0.49M	$0.56M	$0.63M	$0.60M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	143.5	150.5	159.4	169.4	177.0	185.9	196.7	208.3	222.8	237.0
Maximum generation at risk under N-1 (MVA)	18.5	25.5	34.4	44.4	52.0	60.9	71.7	83.3	97.8	112.0
N-1 energy curtailment (MWh)	42.6	71.2	110.9	63.4	27.5	99.5	197.8	452.5	514.1	1077.8
Expected volume of export energy constrained (MWh)	0.2	0.3	0.5	0.3	0.1	0.4	0.9	2.0	2.2	4.7

Notes:

1. “N-1” means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. “N-1 energy at risk” is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. “N-1 hours at risk” is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. “Expected unserved energy” means “N-1 energy at risk” for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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 177,460 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.

Embedded Generation

A total of 183.6 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to TTS 66 kV. It consists of:

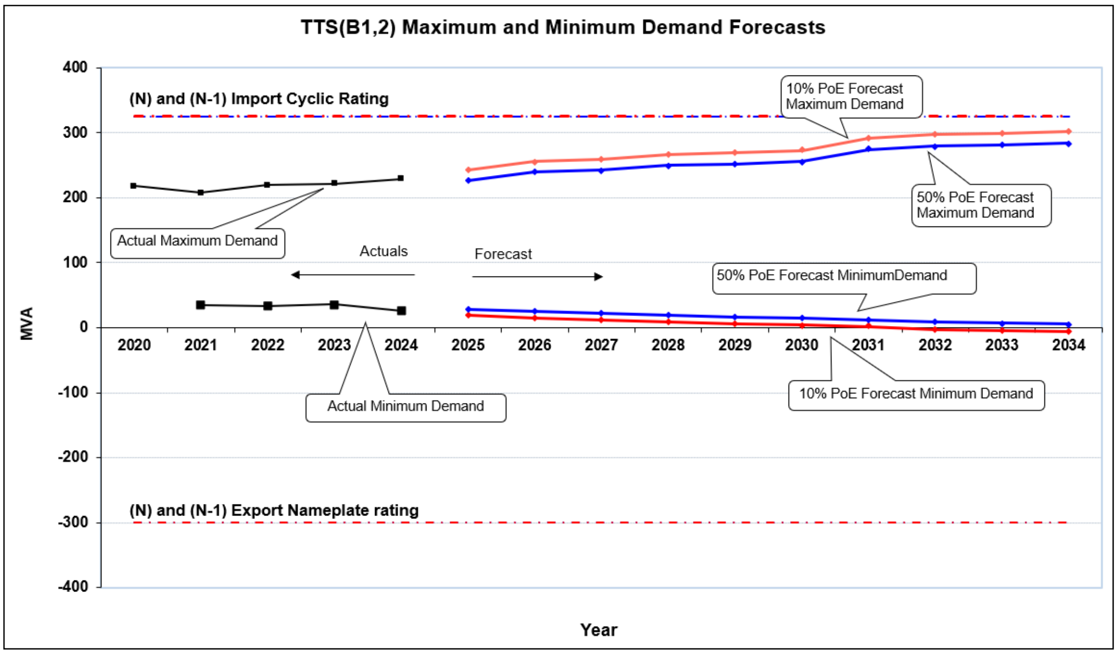
- 172.5 MW of solar PV, which includes 37.9 MW in the AusNet distribution system and 134.6 MW in the Jemena distribution system. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW; and

- 11.1 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 35°C ambient temperature;
- actual station TTS (B12) maximum demand reached 224.32 MW (228.9 MVA) in February 2024; and
- actual station TTS (B12) minimum demand reached 24.4 MW (25.2 MVA) in December 2023.



It is estimated that:

- For 8 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 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 0.95.

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.

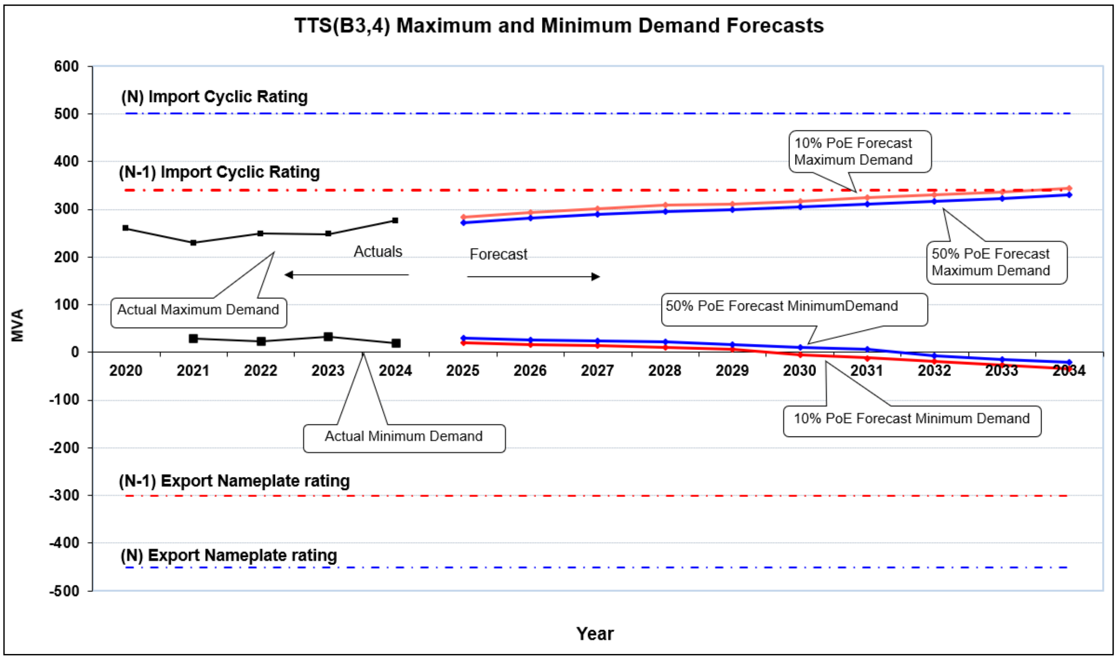
In effect then, the N-1 and N import ratings of the TTS(B12) group are equivalent. Thus there is sufficient import capacity provided by the TTS(B12) group to meet the anticipated maximum demand for the entire forecast period, even under a transformer outage condition.

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 35°C ambient temperature;
- actual station TTS (B34) maximum demand reached 261.3 MW (276.3 MVA) in February 2024; and
- actual station TTS (B34) minimum demand reached 16.5 MW (18.5 MVA) in December 2023.



It is estimated that:

- For 21 hours per year, 95% of peak demand is expected to be reached under the 50th percentile demand forecast.
- The station load power factor at the time of peak demand is 0.95.

In relation to minimum demand, it is estimated that:

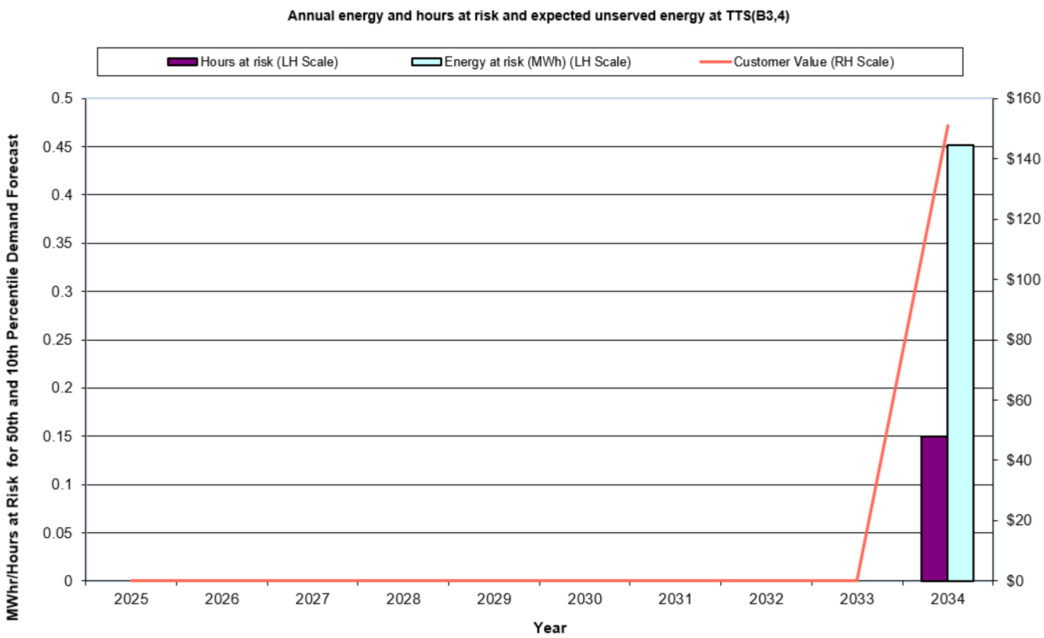
- For 2 hours per year, 95% of the minimum demand is expected to be reached.
- The station load power factor at the time of minimum demand is 0.89.

The above graph shows that from 2034 there is insufficient import capacity at the station to meet maximum demand at the 10th percentile temperature over the forecast period for N-1 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.

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

The bar chart below depicts the energy at risk 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 and N import capability rating. 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 KTS is $51,489 per MWh.



Key statistics relating to energy at risk and expected unserved energy for 2034 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	-	-
Expected unserved energy at 50th percentile maximum demand under N-1 outage condition	-	-
Energy at risk, at 10th percentile maximum demand forecast under N-1 outage condition	1.5	$77,454
Expected unserved energy at 10th percentile maximum demand under N-1 outage condition	0.01	$503
70/30 weighted expected unserved energy value (see below)	**0.5**	**$23,588**

Under the probabilistic planning approach[129], 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[130].

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)[131]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2030 is $23,588.

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 2034 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[132] load shedding

129 See sections 2.3 and 2.4.

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

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

132 Overload Shedding Scheme of Connection Asset.

scheme which is operated by AusNet Transmission Group's TOC[133] 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.

Network Augmentation for alleviation of constraints

On the basis of the medium economic growth scenario and both 50th and 10th percentile weather probability, and the low value of expected unserved energy, terminal station augmentation is unlikely to be economically justified 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.

133 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): 325 MVA

Summer N-1 Station Import Rating: 325 MVA

N-1 Station Export Rating: 300 MVA

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	226.9	239.5	242.4	249.6	252.2	255.6	274.4	279.2	281.3	283.5
50th percentile Winter Maximum Demand (MVA)	205.9	221.2	228.0	237.0	242.5	247.5	265.4	270.8	274.2	277.5
10th percentile Summer Maximum Demand (MVA)	243.3	255.5	258.9	265.9	268.8	272.6	292.0	296.9	299.4	301.9
10th percentile Winter Maximum Demand (MVA)	195.9	211.1	217.7	226.6	231.9	236.6	254.4	259.9	263.2	266.3
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	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	27.8	24.5	21.7	19.0	16.8	14.9	12.2	9.5	7.0	5.4
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 an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.65 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 2019 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): 500 MVA

Summer N-1 Station Import Rating: 340 MVA

N-1 Station Export Rating: 300 MVA

Import	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	271.1	280.7	289.0	295.7	299.0	304.4	310.4	317.1	323.3	329.5
50th percentile Winter Maximum Demand (MVA)	247.8	264.4	279.0	289.2	296.5	304.0	311.1	318.1	325.2	332.2
10th percentile Summer Maximum Demand (MVA)	283.7	293.1	301.8	308.0	311.5	317.3	323.9	330.5	336.9	343.4
10th percentile Winter Maximum Demand (MVA)	238.4	254.8	269.2	279.3	286.5	293.8	300.7	307.6	314.6	321.5
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	1.5
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	0.5
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	0.00
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	0.01
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	$0.00M	$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	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	30.6	26.7	24.8	21.8	16.7	10.7	5.6	-7.8	-14.8	-21.8
Maximum generation at risk under N-1 (MVA)	2.8	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 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 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 2019 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 125,000 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 221.1 MW of embedded generation capacity is installed on the sub transmission and distribution systems connected to TBTS. It consists of:

- About 178.1 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.

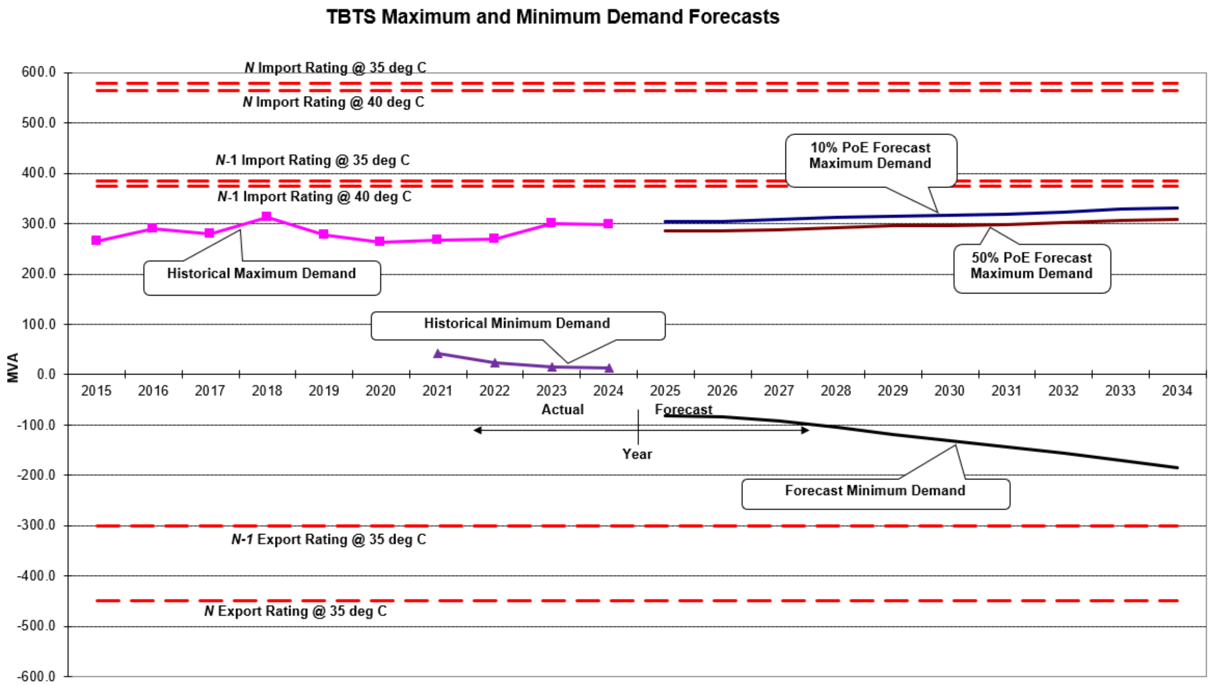
Magnitude, probability, and impact of constraints

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 290.8 MW (298.6 MVA) in summer 2024, which was 1.8 MW lower than the summer 2023 maximum demand.

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 35°C as well as 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 22 MVA of load transfer available at TBTS for summer 2024-25.

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

The station load is forecast to have a power factor of 0.97 at times of peak demand. The demand at TBTS is expected to exceed 95% peak demand for approximately 8 hours per annum.

The station load is forecast to have a power factor of 0.99 at times of minimum demand. The demand at TBTS is expected to reach 95% minimum demand for approximately 1 hour per annum.

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

TYABB TERMINAL STATION 66 kV

Detailed data: Magnitude and probability of loss of load

Distribution Businesses supplied by this station: United Energy Distribution (100%)
Station operational rating (N elements in service): 579 MVA via 2 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: 443 MVA
Summer N-1 Station Export Rating: 300 MVA [See Note 7]
Winter N-1 Station Export Rating: 300 MVA [See Note 7]

Station: TBTS 66kV import	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
50th percentile Summer Maximum Demand (MVA)	287	286	289	292	295	297	298	302	307	309
50th percentile Winter Maximum Demand (MVA)	224	225	227	231	233	234	236	240	244	245
10th percentile Summer Maximum Demand (MVA)	305	305	308	312	315	317	319	323	328	332
10th percentile Winter Maximum Demand (MVA)	236	237	239	243	245	246	248	252	257	258
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	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	0.0	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	0.0	0.0	0.0	0.0
Expected Unserved Energy value at 50th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value at 10th percentile demand	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile vale + 0.3 x 10th percentile value	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k	$0.0k
Hours per year that 95% of maximum demand is expected to be reached	8	8	8	8	8	8	8	9	8	9
Station load power factor at the time of maximum demand	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97

Station: TBTS 66kV export	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
10th percentile minimum demand (MVA)	-80.74	-84.26	-91.65	-105.19	-119.63	-131.94	-144.30	-156.79	-171.23	-184.61
Maximum generation at risk under N-1 (MVA)	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
Expected volume of export energy curtailed (MWh)	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 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 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 2019 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.
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.

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 182.2 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
- 6.4 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.

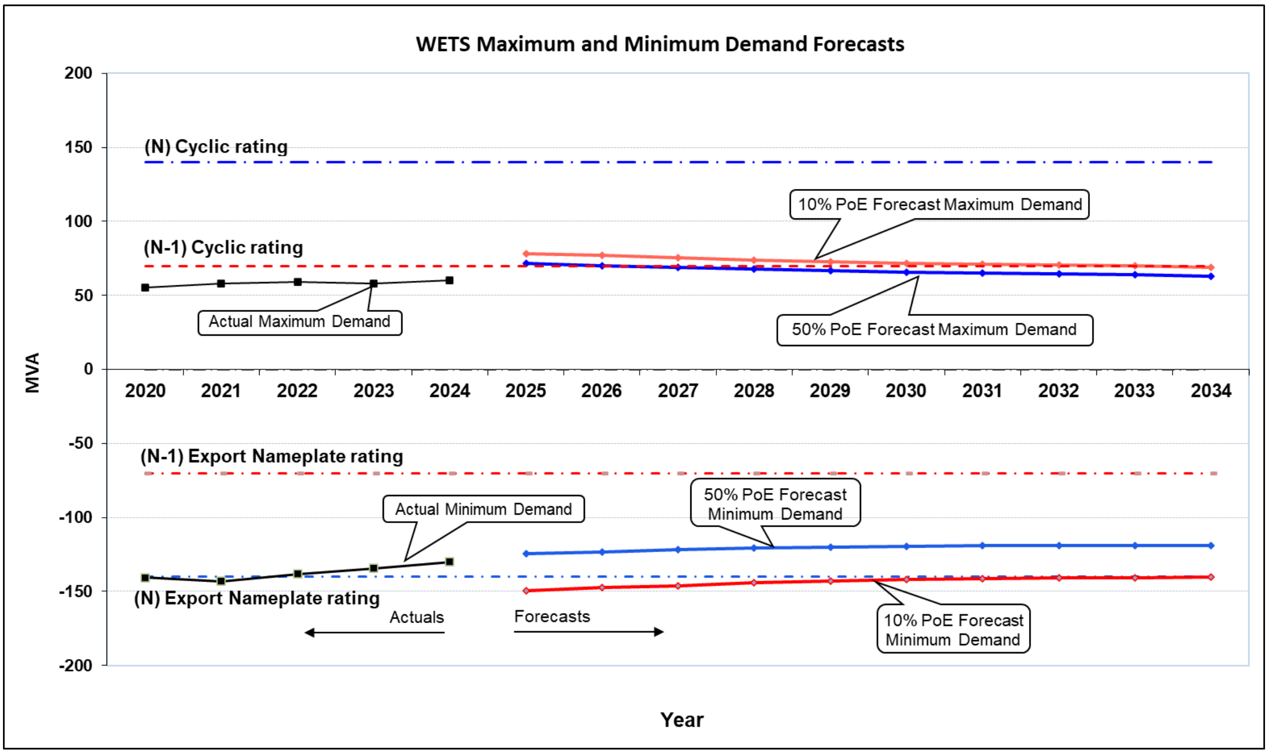
WETS maximum demand occurs in summer. The maximum demand on the station reached 59 MW (60.2 MVA) in summer 2024. Due to the input of generation connected to the station, reverse power flows occur during low load periods. The minimum demand at WETS reached -129 MW (-129.9 MVA) in April 2023.

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 35°C ambient temperature.

In order 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 3 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 0.98.

In relation to minimum demand, it is estimated that:

- For 36 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.

There is a small amount of load at risk under 50th and 10th percentile forecast conditions from 2025 onwards, which is forecast to decline slightly over the ten-year planning horizon. This risk can be managed by utilising load transfers away to adjacent zone substations. There is a potential transfer capacity of 8 MVA from WETS. Therefore, the need for load-driven augmentation is not expected to arise over the next ten years.

The above graph also shows that by 2034, 75 MVA of embedded generation is at risk of curtailment for the loss of one transformer at WETS. This equates to 40,359 MWh of energy at risk of curtailment. Weighting this value by the expected transformer unavailability implies an expected volume of curtailed energy of approximately 200 MWh, which is unlikely to economically justify transmission connection augmentation.

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	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	72.2	70.6	69.4	68.1	66.9	65.9	65.2	64.5	64.0	63.1
50th percentile Winter Maximum Demand (MVA)	47.4	46.1	44.3	42.9	42.2	41.4	40.9	40.2	39.8	38.8
10th percentile Summer Maximum Demand (MVA)	93.0	90.9	88.1	86.0	83.8	82.0	80.9	79.6	79.0	77.6
10th percentile Winter Maximum Demand (MVA)	75.4	73.4	70.4	67.5	66.0	64.9	63.9	62.8	61.8	59.8
N-1 energy at risk at 50% percentile demand (MWh)	1.7	0.3	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)	1.0	0.5	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)	342.6	252.7	158.7	106.9	67.9	47.5	38.0	29.0	25.3	16.6
N-1 hours at risk at 10th percentile demand (hours)	68.0	54.0	37.5	27.0	19.0	13.5	10.5	8.0	7.5	6.5
Expected Unserved Energy at 50th percentile demand (MWh)	0.01	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)	1.48	1.09	0.69	0.46	0.29	0.21	0.16	0.13	0.11	0.07
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	$0.08M	$0.06M	$0.04M	$0.02M	$0.02M	$0.01M	$0.01M	$0.01M	$0.01M	$0.00M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th precentile value + 0.3 X 10th percentile value	$0.02M	$0.02M	$0.01M	$0.01M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	157.5	155.5	152.9	151.5	149.7	148.7	147.8	146.7	146.0	145.2
Maximum generation at risk under N-1 (MVA)	87.5	85.5	82.9	81.5	79.7	78.7	77.8	76.7	76.0	75.2
N-1 energy curtailment (MWh)	53539.7	51178.3	49059.1	47184.7	45533.7	44553.7	43568.7	42765.4	41875.4	40359.4
Expected volume of export energy constrained (MWh)	1220.5	920.7	699.0	537.9	417.8	356.9	308.2	274.3	243.2	200.2

Notes:

1. "N-1" means station output capability rating with outage of one transformer. The winter rating is at an ambient temperature of 5 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which specified demand forecast exceeds the N-1 capability rating.
3. "N-1 hours at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating.

4. "Expected unserved energy" means "N-1 energy at risk" for the specified demand forecast multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with a duration of 2.65 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 relevant climate zone and sector VCR values given in the AER VCR December 2019 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:

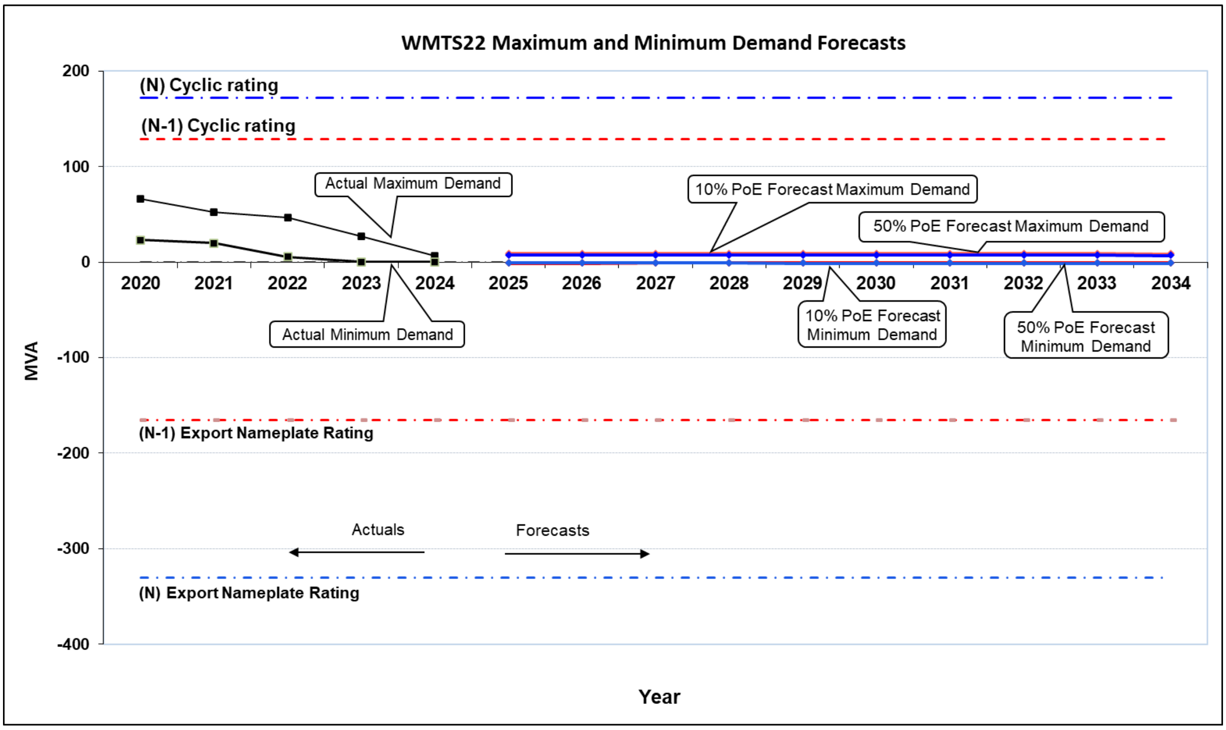
- For 5 hours per year, 95% of peak demand is expected to be reached under the 50th percentile summer demand forecast.
- The station load power factor at the time of peak demand is 0.98.

In relation to minimum demand, it is estimated that:

- For 5 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 0.8.

Magnitude, probability and impact of loss of load

The graph below depicts the station's operational N rating for all transformers in service and the N-1 rating (at 35 degrees ambient temperature), and the latest 10th and 50th percentile maximum demand forecasts for the next ten years. The N-1 ratings are restricted by over-voltage limits on transformer tapping.



The graph shows that there is sufficient capacity at the station to supply the forecast 50th and 10th percentile demands over the forecast period, even with one transformer out of service. 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 of 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 48,330 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 34 MW of solar PV is installed on WMTS 66 which includes 20.8 MW in the CitiPower distribution system and 13 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 MW (263.1 MVA) in summer 2024 which was 32 MW lower than summer 2023.

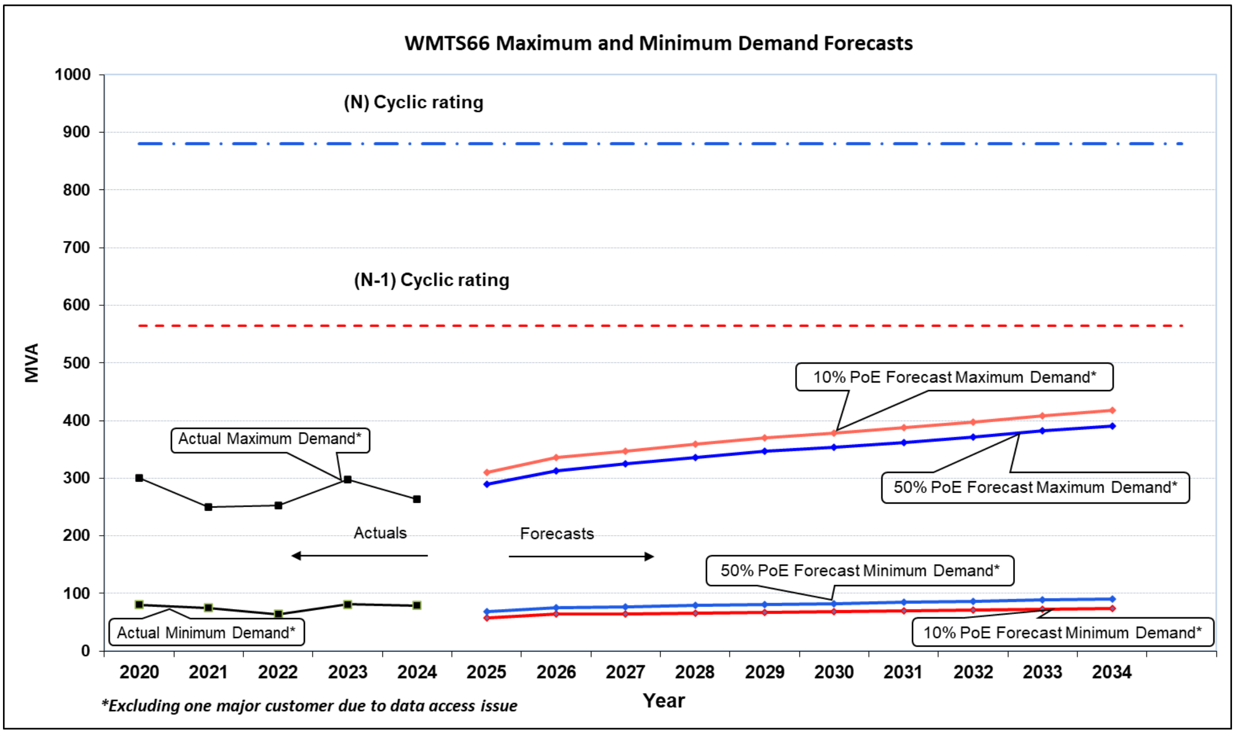
The graph below shows:

- the station's N and N-1 import cyclic ratings at 35ºC 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. 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 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 11 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 180 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 0.97.

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 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.

Embedded generation

A total of 123.4 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
- 58.4 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

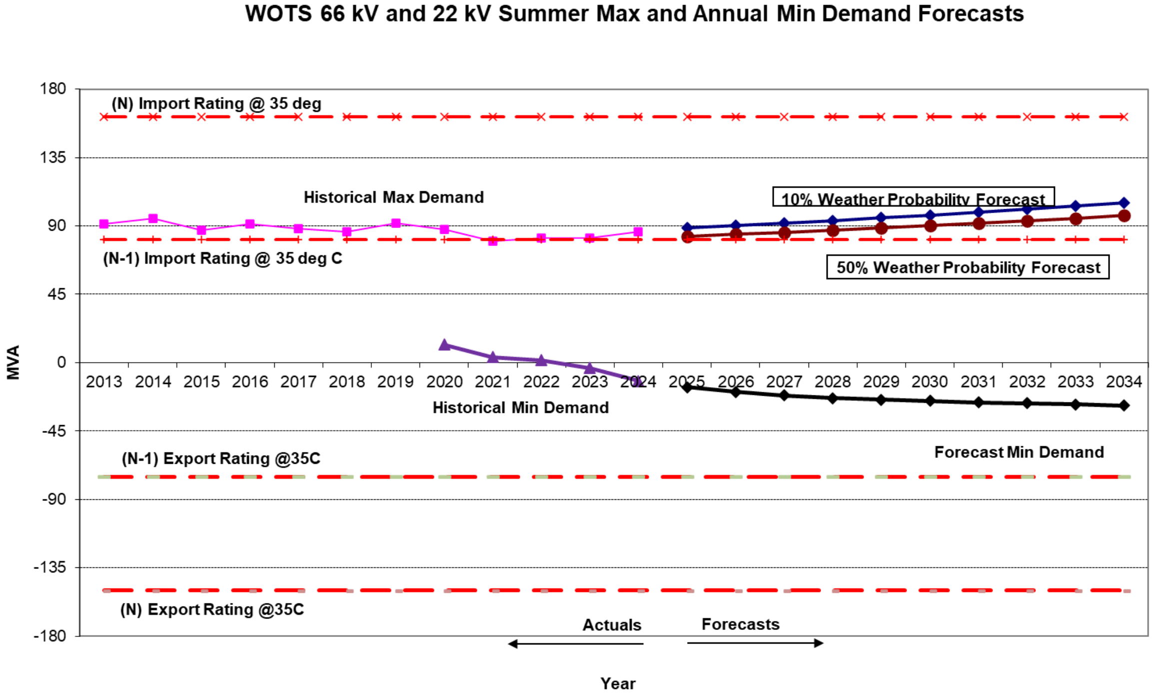
Maximum demand at WOTS occurs in summer, and the combined 66 kV and 22 kV summer maximum demand is forecast to gradually increase for the next ten years. To accurately assess the transformer loading, the 66 kV and 22 kV loads need to be considered together because of the physical arrangement of the transformer 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 2023/24 was 84.84 MW (86.19 MVA).

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 35°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 maximum demand at WOTS 66 kV and 22 kV is expected to exceed 95% of the 50th percentile peak demand for 4 hours per annum. The station load has a power factor of 0.984 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:

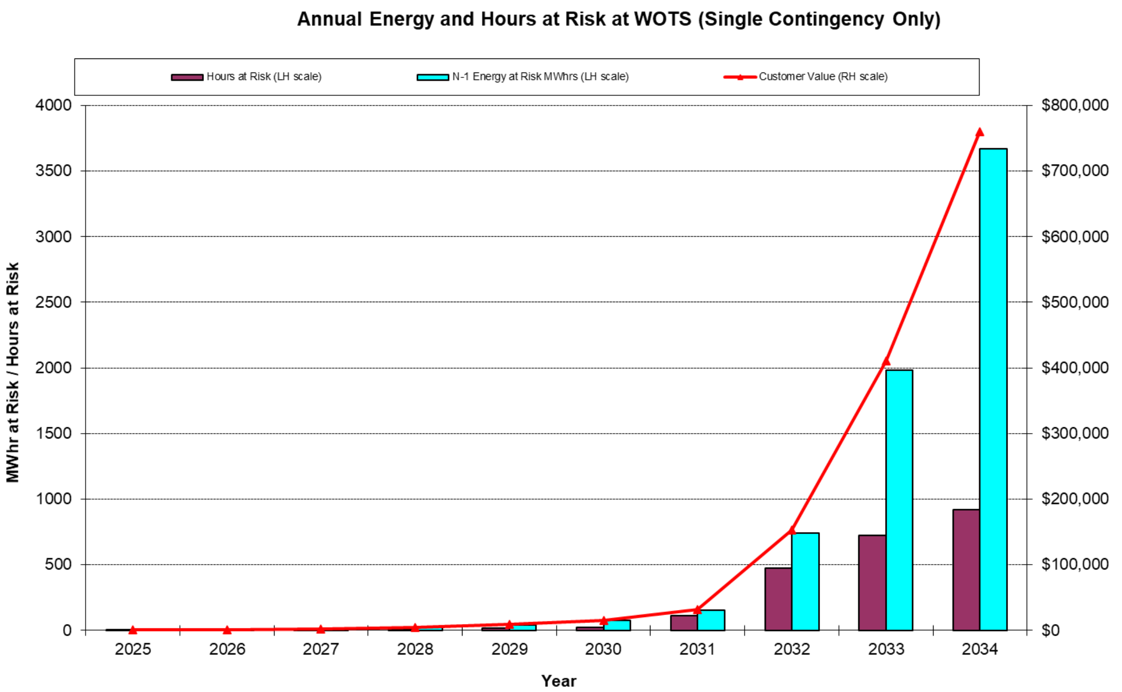
- For 13.75 hours per year, 95% of the minimum demand is expected to be reached.
- The station load has a power factor of -0.995 at the time of minimum demand.

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.

The combined 66 kV and 22 kV winter maximum demand at WOTS is less than the summer maximum demand and the station winter import rating is higher than the summer rating. Forecast 50th and 10th percentile winter maximum demand at WOTS 66 kV and 22 kV are expected to exceed the "N -1" winter station import rating in the next ten years in 2031 and 2027 respectively.

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 ten year planning period.

The bar chart below depicts the energy at risk with one transformer out of service for the 50th percentile summer maximum demand forecast, and the hours each year that the 50th percentile summer 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 50th percentile maximum demand forecast. The VCR at the station is $49,954 per MWh.



Comments on Energy at Risk - Assuming HPS generation is not available

Key statistics for 2033/34 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	401	$20.01 million
Expected unserved energy at 50th percentile maximum demand	0.7	$0.03 million
Energy at risk at 10th percentile maximum demand forecast	1,761	$87.96 million
Expected unserved energy at 10th percentile maximum demand	2.9	$0.15 million
70/30 weighted expected unserved energy value (see below)	**1.4**	**$0.07 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 from 2023. As such, due to the dedicated nature of this spare, the standard 2.65 month "Major Outage" duration (as explained in section 4.6) does not apply. A 1 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[134], 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 outage[135]. 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)[136]. Applying AEMO's approach, the weighted average cost of expected unserved energy in 2033/34 is \$0.07 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[137] to protect the connection assets from overloading[138], 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 ten year planning horizon for the 50th or 10th percentile summer maximum demand forecasts.

134 See section 3.1.

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

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

137 Transmission Operation Centre.

138 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 0.984 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 has initiated a Regulatory Investment Test for Transmission (RIT-T) to address the existing constraints on the sub-transmission and distribution network in north-eastern Victoria (Wodonga - Barnawartha area) to enable more renewable generation to connect to this part of AusNet Services' network. All network options considered in the RIT-T, including the preferred option identified in the Project Assessment Conclusions

Report (PACR)[139], involve the installation and commissioning of the WOTS spare transformer (330/66/22 kV 75 MVA) as the third in-service transformer at WOTS. The RIT-T is expected to be completed in 2025, however current assessments indicate the earliest delivery timing in 2026/27. The estimated annualised cost of the transformer is approximately $2.4 million.

There is expected to be sufficient station export capability to accommodate existing 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, export constraints, energy at risk and expected unserved energy assuming embedded generation is not available.

[139] Connection Enablement: Wodonga – Barnawartha in North-Eastern Victoria PACR (ausnetservices.com.au)

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	162	MVA via 2 transformers (Summer peaking)
Summer import N-1 Station Rating	81	MVA [See Note 1 below for interpretation of N-1]
Winter import N-1 Station Rating	87	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	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
50th percentile Summer Maximum Demand (MVA)	83.2	84.4	85.7	87.1	88.6	90.2	91.7	93.4	95.1	96.9
50th percentile Winter Maximum Demand (MVA)	76.5	78.3	80.4	82.4	84.4	86.3	88.4	90.5	92.6	94.8
10th percentile Summer Maximum Demand (MVA)	88.7	90.2	91.8	93.5	95.3	97.1	99.0	101.0	103.0	105.1
10th percentile Winter Maximum Demand (MVA)	83.8	85.6	87.9	90.1	92.3	94.3	96.4	98.6	100.7	102.9
N - 1 energy at risk at 50th percentile demand (MWh)	3	5	10	22	43	74	120	187	278	401
N - 1 hours at risk at 50th percentile demand (hours)	2	3	5	12	18	25	38	52	66	91
N - 1 energy at risk at 10th percentile demand (MWh)	80	136	219	333	480	660	871	1,128	1,425	1,761
N - 1 hours at risk at 10th percentile demand (hours)	34	46	64	82	100	119	137	156	179	202
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.5	0.7
Expected Unserved Energy at 10th percentile demand (MWh)	0.1	0.2	0.4	0.6	0.8	1.1	1.5	1.9	2.4	2.9
Expected Unserved Energy value at 50th percentile demand	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.01M	$0.01M	$0.02M	$0.02M	$0.03M
Expected Unserved Energy value at 10th percentile demand	$0.01M	$0.01M	$0.02M	$0.03M	$0.04M	$0.05M	$0.07M	$0.09M	$0.12M	$0.15M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	$0.00M	$0.00M	$0.01M	$0.01M	$0.01M	$0.02M	$0.03M	$0.04M	$0.05M	$0.07M
Export	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
10th percentile minimum Demand (MVA)	-16.2	-19.2	-21.6	-23.3	-24.4	-25.2	-26.1	-26.8	-27.5	-28.1
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 summer rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 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 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 2019 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.