

# TRANSMISSION CONNECTION PLANNING REPORT

Produced jointly by the  
Victorian Electricity Distribution Businesses

2018



# TRANSMISSION CONNECTION PLANNING REPORT

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## EXECUTIVE SUMMARY

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

Under their Electricity Distribution Licences, the DBs have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the shared transmission network<sup>2</sup>. 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 which are owned, operated, and maintained by the transmission asset owner, AusNet Transmission Group.

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

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

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

The DBs’ approach is consistent with the probabilistic approach applied by the Australian Energy Market Operator (AEMO) in planning the Victorian shared transmission network<sup>3</sup>. An important point to note about the use of a probabilistic approach is that it involves customers accepting the risk that there may be circumstances when the available terminal station capacity will be insufficient to meet demand, and significant load shedding could be required.

An estimate of the value that customers place on supply reliability (“VCR”) is a key input to probabilistic network planning. Estimating the VCR is inherently uncertain, and AEMO’s

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

<sup>2</sup> 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.

<sup>3</sup> See: [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf)

current estimate (published in its September 2014 VCR Final Report<sup>4</sup>) is substantially lower than its previous estimate. In the 2017 Transmission Connection Planning Report, we highlighted the impact of AEMO's lower VCR estimate by reporting the investment signals using both the current and previous estimates where the change in VCR has a material impact on the timing of augmentation over the next 5 years. We adopt the same approach in this report.

AEMO's 2014 VCR estimate has been escalated to 2018 values using the escalation adjustment set out in AEMO's VCR Application Guide. The 2018 VCR and AEMO's previous VCR estimate (also escalated to 2018 dollars) are used to calculate expected unserved energy, and to provide an indication of the timing of remedial action to address an emerging constraint.

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

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

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

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

The assessment presented in this report, and summarised in the table on the following pages sets out the DBs' Transmission Connection Planning Report for 2018. It is emphasised that this report does not present the detailed investment decision analysis that is required under the RIT-T. Rather, the report presents a high-level indication of the expected balance between capacity and demand at each terminal station over the forecast period and the likely investment requirements.

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

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<sup>4</sup> See: <http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review>

The DBs are required by clause 3.4 of the Victorian Electricity Distribution Code to provide, among other things, an indication of the magnitude, and potential impact of loss of load for each transmission connection.

This information is summarised in the table on the following pages, in the form of estimates of “expected unserved energy”<sup>5</sup> for each terminal station in the year in which augmentation of the terminal station is likely to be required. Expected unserved energy estimates are provided for two forecasts of demand: the first forecast has a 10% probability of being exceeded, while the second forecast has a 50% probability of being exceeded. The demand forecasts used in the preparation of this report are set out in the 2018 Terminal Station Demand Forecasts, which is prepared by the DBs and published alongside this report.

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

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

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

- Adam Ryan, Network Optimisation Manager, CitiPower / Powercor, phone 9683 4380.
- Jason Pollock, Lead Engineer, Strategic Network Planning, AusNet Electricity Services, phone 9695 6490.
- Rodney Bray, Manager Network Planning and Strategy, United Energy, phone 8846 9745.
- Ashley Lloyd, Network Capacity Planning and Assessment Manager, Jemena, phone 9173 8279.

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

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

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

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

## Summary of risk assessment and options for alleviation of constraints

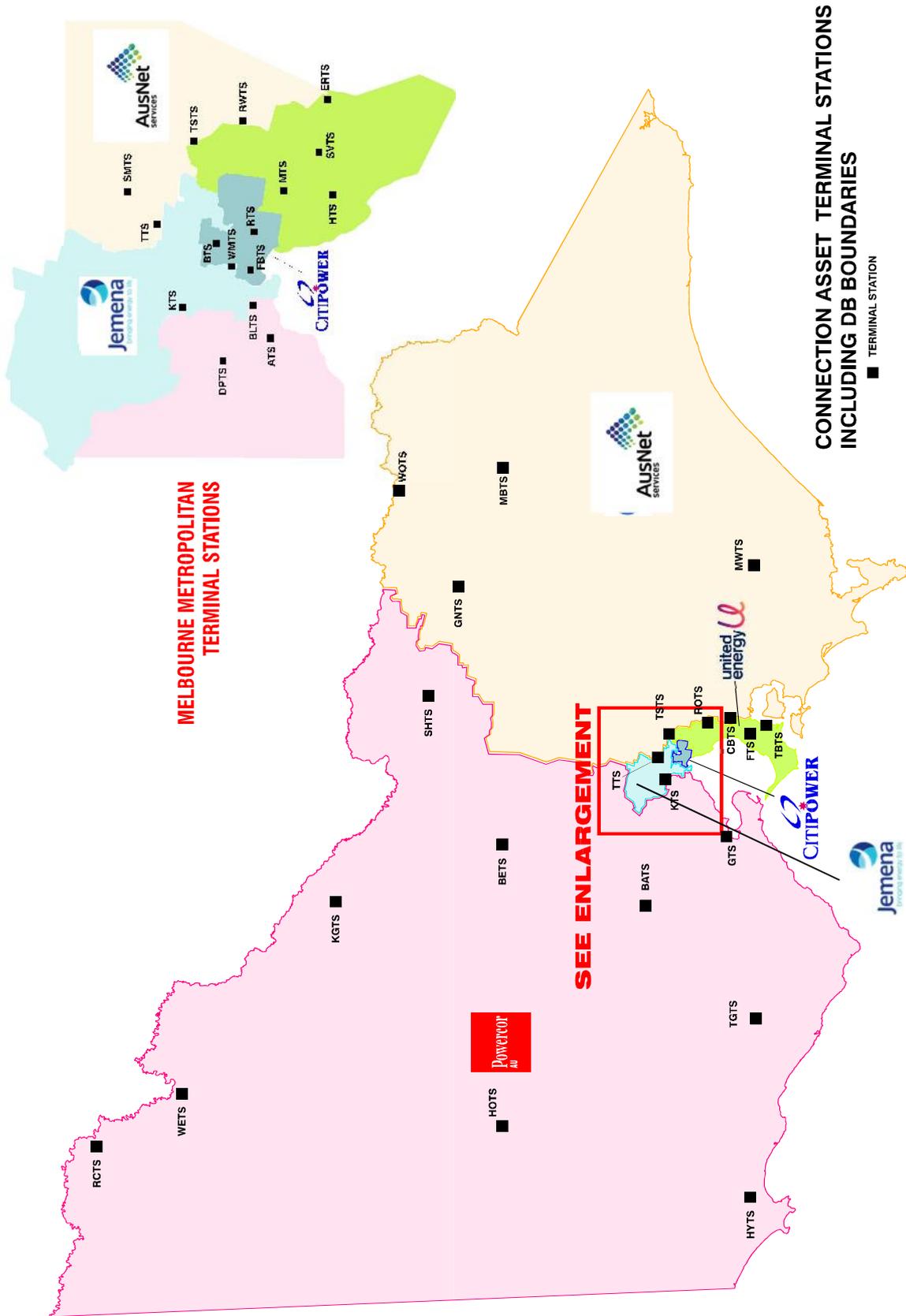
Terminal Station	Indicative timing for completion of preferred network solution (using 2018 VCR)	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2018 VCR)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10 <sup>th</sup> percentile demand forecast	50 <sup>th</sup> percentile demand forecast			
Altona – Brooklyn (ATS/BLTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Altona no 3 & 4 (ATS West) 66 kV	By 2025 (or 2021 based on AEMO's previous VCR estimate escalated to 2018 dollars)	43.1 MWh in 2025 (\$1.82 million)	23.6 MWh in 2025 (\$1.0 million)	Install additional transformation capacity and reconfigure 66 kV exits at ATS.	\$1.04 million	Demand reduction; Local generation.
Ballarat (BATS)	Not before 2028	2.1 MWh in 2028 (\$79,100)	0.18 MWh in 2028 (\$6,850)	Install a third 150 MVA 220/66 kV transformer. There are presently several large 66 kV wind farm proposals in the area which may drive the need for an additional 220/66 kV transformer at BATS to accommodate the reverse power flow expected at BATS.	\$0.82 million	Demand reduction
Bendigo 22 kV (BETS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Bendigo 66 kV (BETS 66 kV)	Not before 2028	12.1 MWh in 2028 (\$0.41 million)	5.3 MWh in 2028 (\$0.18 million)	Install an additional 150 MVA 220/66 kV transformer.	\$1.04 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.					
Brunswick 22 kV (BTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within 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.					

Terminal Station	Indicative timing for completion of preferred network solution (using 2018 VCR)	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2018 VCR)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10 <sup>th</sup> percentile demand forecast	50 <sup>th</sup> percentile demand forecast			
Cranbourne 66 kV (CBTS 66 kV)	2018/19 (or earlier based on AEMO's previous VCR estimate escalated to 2018 dollars. See comments on the preferred network solution.)	70 MWh in 2018/19 (\$2.63 million)	17.6 MWh in 2018/19 (\$0.67 million)	Install a fourth transformer.  The maximum demand forecasts used in this 2018 report are significantly higher than last year's forecasts. As a consequence, a fourth transformer could be economically justified as soon as 2018/19. However, after load transfers and emergency ties are taken into account, the optimal economic timing of augmentation would be deferred by approximately 2 years (to 2020/21).	\$1.2 million	Demand reduction; Local generation.
Deer Park (DPTS)	Not before 2028	6.5 MWh in 2028 (\$0.28 million)	1.5 MWh in 2028 (\$62,400)	Install a third transformer	\$1.04 million	Demand reduction; Local generation.
East Rowville (ERTS)	No demand-driven augmentation of capacity is expected to be required within 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					
Frankston (FTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Geelong (GTS)	Not before 2028	5.3 MWh (\$213,700)	0.6 MWh (\$25,300)	Install a fifth transformer.	\$1.04 million	Demand reduction; Local generation
Glenrowan (GNTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Heatherton (HTS)	Not before 2028	0.4 MWh (\$16,600)	Nil	Establish a new 220/66 kV terminal station in Dandenong. This option alleviates a number of emerging transmission, connection asset and sub-transmission limitations including at HTS.	\$4.1 million	Demand reduction; Local generation
Horsham (HOTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					

Terminal Station	Indicative timing for completion of preferred network solution (using 2018 VCR)	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2018 VCR)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10 <sup>th</sup> percentile demand forecast	50 <sup>th</sup> percentile demand forecast			
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 capacity at the station to supply all expected 22 kV load over the forecast period, even with one transformer out of service.					
Keilor (KTS)	Not before 2028	2.3 MWh (\$91,200)	Nil	No augmentation of capacity is expected to be required within the ten year planning horizon. Over the forecast period, the risk to supply reliability will be mitigated through contingency plans to transfer load quickly, where possible, to adjacent terminal stations.	N/A	Demand reduction; Local generation
Kerang (KGTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Malvern 22 kV (MTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within 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.					
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.					
Morwell (MWTS)	Not before 2028 (assuming a total contribution of 60 MVA from existing embedded generators)	2.5 MWh in 2018/19 (\$0.1 million)	0.05 MWh in 2018/19 (\$2,200)	Demand at MWTS is forecast to remain flat over the ten year planning period. In view of the current and forecast level of expected unserved energy at MWTS, implementation of a network solution is unlikely to be economic over the ten year planning horizon.	N/A	Continued availability of Bairnsdale and other embedded generation over the ten year planning horizon will obviate the need for network augmentation.
Red Cliffs 22 kV (RCTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					

Terminal Station	Indicative timing for completion of preferred network solution (using 2018 VCR)	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2018 VCR)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10 <sup>th</sup> percentile demand forecast	50 <sup>th</sup> percentile demand forecast			
Red Cliffs 66 kV (RCTS 66 kV)	Not before 2028	1.67 MWh (\$57,500)	0.16 MWh (\$5,500)	The current and forecast level of expected unserved energy at RCTS 66 indicates that implementation of a network solution is unlikely to be economic over the ten year planning horizon. A contingency plan to transfer approximately 42 MVA from RCTS 66 to WETS will be implemented in the event of the loss of one of the RCTS 220/66 kV transformers.	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.					
Richmond 66 kV (RTS 66 kV)	<p>AusNet Transmission Group has completed its asset replacement project at RTS 66 kV, which has involved the replacement of five aging 150 MVA transformers with three 225 MVA transformers.</p> <p>Over the first two years (2019 and 2020) of the ten year planning horizon there is some load at risk at the station. This will be managed through the use of a fourth temporary 150 MVA transformer. After the 2020 summer, MP zone substation will be transferred from RTS to BTS and this removes the load at risk until 2028 when the 10<sup>th</sup> percentile demand forecast will reach the N-1 rating and at this point load transfers will be used to manage any load at risk. Therefore, the need for augmentation of capacity at RTS 66 kV is not expected to arise over the next ten years.</p>					
Ringwood 22 kV (RWTS 22 kV)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Ringwood 66 kV (RWTS 66 kV)	To be determined, but estimated to be around 2023	"N" and "N-1" expected unserved energy is 549 MWh in 2027/28 (\$23 million)	Nil	Rebalancing loads across the two bus groups at the station could be implemented to manage the "N" risk on bus group 1-3. AusNet Electricity Services and United Energy will jointly identify the works required to rebalance loads in the most efficient manner, following which the cost and optimal timing of the required works will be established.	To be determined	Demand reduction; Local generation
Shepparton (SHTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					

Terminal Station	Indicative timing for completion of preferred network solution (using 2018 VCR)	Expected unserved energy for the year shown in the column to the left (in MWh, and valued at 2018 VCR)		Preferred network solution	Indicative annual cost of preferred network solution	Potentially feasible non-network solutions
		10 <sup>th</sup> percentile demand forecast	50 <sup>th</sup> percentile demand forecast			
South Morang (SMTS)	Not before 2028	48 MWh in 2027/28, assuming no generation from Somerton PS (\$1.66 million)	20 MWh in 2027/28, assuming no generation from Somerton PS (\$0.69 million)	Install a third 225 MVA 220/66 kV transformer at SMTS.	\$1.3 million (including the cost of fault limiting reactors)	Demand Reduction Embedded generation
Springvale (SVTS)	Not before 2028	0.17 MWh (\$7,000)	Nil	Establish a new terminal station in the Dandenong area to off-load SVTS.	\$4.1 million	Demand reduction; Local generation
Templestowe (TSTS)	Not before 2028	1.1 MWh (\$39,000)	0.03 MWh (\$1,100)	Install a fourth 150 MVA 220/66 kV transformer at TSTS.	\$1.2 million	Demand reduction; Local generation
Terang (TGTS)	Not before 2028	29.6 MWh (\$1.14 million)	4.2 MWh (\$0.16 million)	Install a third 220/66 kV transformer (150 MVA) at TGTS	\$1.04 million	Demand reduction; Local generation
Thomastown (TTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Tyabb (TBTS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
Wemen (WETS)	No demand-driven augmentation of capacity is expected to be required within the ten year planning horizon.					
West Melb 22 kV (WMTS 22 kV)	No augmentation of capacity is expected to be required within the ten year planning horizon. Under joint plans developed by CitiPower and AusNet Transmission Group, existing load supplied from WMTS 22 kV will be transferred to adjacent stations over the next six years, to enable the retirement of all of the existing WMTS 22 kV systems by the end of 2025.					
West Melb 66 kV (WMTS 66 kV)	Following the transfer of load to the new BTS in late 2016, there is sufficient capacity at WMTS 66 kV to supply the forecast 10th percentile and 50th percentile demand over the planning period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.					
Wodonga (WOTS)	Not before 2028	5.6 MWh in 2028 (\$0.23 million) excluding generation from Hume PS or any other source	1.4 MWh in 2028 (\$59,000) excluding generation from Hume PS or any other source	In view of the forecast level of expected unserved energy, there are currently no plans to implement a network solution within the ten year planning horizon.	N/A	Demand management; Local generation



# 1 INTRODUCTION AND BACKGROUND

## 1.1 Purpose of this report

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

It is emphasised that this report does not present detailed investment decision analyses. Rather, the report presents a high-level indication of the expected balance between capacity and demand at each terminal station<sup>9</sup> over the forecast period and the likely investment requirements.

Data presented in this report may indicate an emerging major constraint. Therefore, this report provides a means of identifying those terminal stations where further consultation and detailed analysis - in accordance with the Regulatory Investment Test for Transmission - is required. This report also provides preliminary information on potential opportunities to prospective proponents of alternatives to network augmentations at terminal stations where remedial action may be required. Providing this information to the market should facilitate the efficient development of network and non-network solutions to best meet the needs of load 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 have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the Victorian shared transmission network;<sup>10</sup> and
- the Australian Energy Market Operator (AEMO) is responsible for planning and directing the augmentation of the shared transmission network.

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

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

<sup>7</sup> Version 9, effective from December 2015.

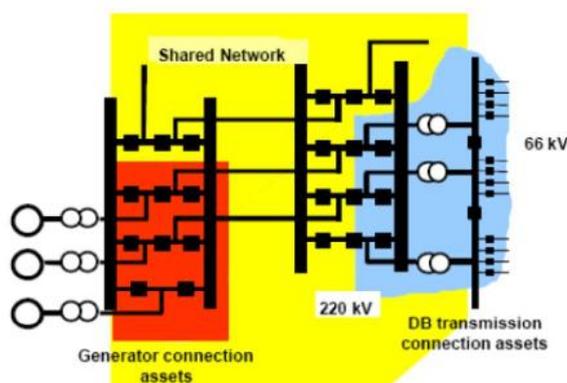
<sup>8</sup> Version 115 of the Rules was in force at the time of preparing this report.

<sup>9</sup> A terminal station is a facility that connects a distribution network to the shared transmission network.

<sup>10</sup> The shared transmission network is the main extra high voltage network that provides or potentially provides supply to more than a single point. This network includes all lines rated above 66 kV and main system tie transformers that operate at two or three voltage levels above 66 kV.

Figure 1 below provides an example to illustrate the distinction between the shared transmission network and transmission connection assets in a notional network. The delineation between shared network assets 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.

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



In regions other than Victoria, the Rules<sup>11</sup> set out arrangements to promote contestability in the provision of connection services for identified user groups other than networks (such as generators or large directly connected customers). Specifically, the Rules distinguish between:

- a) Identified user shared assets, which broadly describe the collection of components that are required to facilitate the connection of a connecting party to the shared transmission network and which, once commissioned, form part of the shared transmission network; and
- b) Dedicated connection assets, which describe the collection of components that are used to connect a connecting party to the shared transmission network and which, once commissioned, are able to be isolated from electricity flows on the transmission network.

In Victoria, however, the framework under which connections to the transmission network occur is fundamentally different to the processes and principles underlying the connection framework used in the rest of the NEM. This is because AEMO is authorised to exercise declared shared network functions in Victoria. In that role, AEMO determines whether works are 'contestable' and so are procured through a competitive tender process, or 'non-contestable' and so provided by the incumbent declared transmission system operator. As such, the Rules definitions noted above do not apply in Victoria.

In relation to the development of transmission connection facilities and the downstream sub-transmission and distribution systems, the planning arrangements in Victoria are aimed at fostering efficient and coordinated outcomes for electricity consumers. The Victorian framework recognises that the DBs are best placed to determine the optimum level of investment in, and configuration of, distribution system capacity and transmission connection capacity, having regard to:

- the needs and preferences of the end consumers of electricity;

<sup>11</sup> National Electricity Amendment, (Transmission Connection and Planning Arrangements) Rule 2017 No.4, 30 May 2017.

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

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

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

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

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

The DBs also liaise regularly with AusNet Transmission Group to coordinate their transmission connection augmentation plans with AusNet Transmission Group's asset renewal and replacement plans<sup>12</sup>.

## 1.3 DBs' obligations as transmission connection planners

### 1.3.1 Victorian regulatory instruments

Clause 14 of each DB's Distribution Licence states:

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

<sup>12</sup> Chapter 4 of AEMO's 2018 Victorian Annual Planning Report provides information on AusNet Transmission Group's plans regarding asset retirement, replacement and deratings. The report is available from: [https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/VAPR/2018/2018-Victorian-Annual-Planning-Report.pdf](https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2018/2018-Victorian-Annual-Planning-Report.pdf).

AusNet Transmission Services' asset renewal plan is available from: [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/VAPR/2018/AusNet-Services-asset-renewal-plan-2018.pdf](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2018/AusNet-Services-asset-renewal-plan-2018.pdf)

The licence defines “transmission connection assets” as:

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

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

Clause 3.4 of the Victorian Electricity Distribution Code states:

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

3.4.2 The report must include the following information:

- (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.

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

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

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

- specify the capital and other works proposed by the *Melbourne CBD distributor* in order to achieve the security of supply objectives for the Melbourne CBD that are specified in the plan; and
- meet the regulatory test (which is discussed in further detail in section 1.3.2 below).

This provision establishes a separate planning process that applies to the network supplying the Melbourne CBD only. Details of the CBD security of supply upgrade plan are available from CitiPower's website at the following address:

<https://www.powercor.com.au/about-us/electricity-networks/metro-and-cbd-security-of-supply/>

The upgrade will protect Melbourne's electricity supply from a prolonged blackout should there be major failures (i.e. the loss of two or more 66 kV subtransmission elements) within the electricity networks supplying the CBD and inner Melbourne area.

### **1.3.2 National Electricity Rules**

Part D of Chapter 5 of the Rules<sup>13</sup> sets out provisions governing the planning and development of networks. These provisions require, amongst other things, Transmission and Distribution Network Service Providers to:

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

Clause 5.13.2 of the Rules requires Distribution Network Service Providers to publish a Distribution Annual Planning Report (DAPR). The DAPR must contain the information specified in schedule 5.8 of the Rules, unless that information is provided in accordance with jurisdictional electricity legislation<sup>14</sup>.

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

<sup>13</sup> Version 115 of the Rules was in force at the time of preparing this report.

<sup>14</sup> 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."

**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.	Section 2.
S5.8(b)(2)(i), (iv), (v), (vi), (vii), (viii), and (ix)	Load forecasts and forecasts of capacity.	Section 4, Section 5.6 and 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(h)	The results of joint planning undertaken with Transmission Network Service Providers.	Section 1.2 describes joint planning arrangements. The Executive Summary and individual risk assessments for each terminal station describe the results of joint planning.
S5.8(i)(1)	The results of joint planning undertaken with other Distribution Network Service Providers (DNSPs)	As above

Each DB also publishes the information required by the DAPR, including the above information where applicable, in accordance with the AER's Distribution System Limitation Template. The purpose of the template is to facilitate the publication of information on system limitations required by the DAPR in a useable, consistent, accessible format to assist third parties to propose alternative options to address system limitations.

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

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

The operation of the s-factor relates to the distribution network, and therefore is not directly relevant to the reliability of the transmission system. However, under clause 3.3(a)(6) of the STPIS<sup>15</sup>, the DBs are exposed to financial penalties if load interruptions are caused by a failure of transmission connection assets, where the interruptions are due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.

<sup>15</sup> AER, *Electricity Distribution Network Service Providers - Service Target Performance Incentive Scheme*, November 2009. It is noted that on 14 December 2017, the AER issued a draft amended Service Target Performance Incentive Scheme (Version 2), which continues to include this provision. At the time of writing (August 2018) the AER had not issued a final amended Version 2 of the Scheme.

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

#### **1.3.4 Role of transmission connection asset owners in delivering connection services**

With the exception of the connection assets at the Deer Park Terminal Station, the transmission assets that provide DB connection services are located within terminal stations which are owned, operated, and maintained by AusNet Transmission Group<sup>16</sup>. Connection services are provided by the owners of the transmission connection assets in accordance with their connection agreements with the relevant DBs. These agreements set out, amongst other things, the standard of connection services to be provided.

In addition, the revenue caps applying to AusNet Transmission Group and TransGrid contain a Service Target Performance Incentive Scheme (STPIS), in accordance with clause 6A.7.4 of the National Electricity Rules. The STPIS aims to balance the incentive to minimise expenditure against the benefits of improving reliability for customers, by providing the transmission connection asset owners with a financial incentive to improve service performance.

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

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

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

- (a) proponent name and contact details;
- (b) a detailed description of the proposal;
- (c) electrical layout schematics;
- (d) a firm nominated site;

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<sup>16</sup> The connection assets at Deer Park Terminal Station were commissioned in September 2017, and are owned, operated and maintained by TransGrid.

- (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.

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

## 1.5 Implementing Transmission Connection Projects

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

### 1.5.1 Land Acquisition

Network solutions may require land acquisition. The process of land acquisition for new terminal stations may be complex especially in metropolitan areas. 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. DBs would need to seek AusNet Transmission Group's consent to use any reserved land for transmission connection development.<sup>17</sup>

<sup>17</sup> Electricity Industry Guideline No. 18 (*Augmentation and Land Access Guidelines*) issued by the ESC on 1 April 2005 may govern access to such sites, in some circumstances. See: <https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-codes-guidelines-policies-and-manuals>

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

### **1.5.2 Connection Application to AEMO**

Where a network solution requires new connection points with the shared transmission network to be established, a connection agreement with AEMO is required in accordance with clause 5.3 (Establishing or Modifying Connection) of the National Electricity Rules. As noted in section 1.2, the 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. It is also noted that AEMO's requirements regarding new connections must be finalised through a joint planning process involving AEMO and the relevant DBs. These activities can increase the lead time for delivery of projects by some months.

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

A more detailed overview of the Victorian transmission connections process is available from AEMO's web page at: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/~/link.aspx?id=8F98AAFA209C481E96617AFFCC30C88B&z=z>.

### **1.5.3 Connection Application to AusNet Transmission Group**

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

### **1.5.4 Town Planning Permit**

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

- flora and fauna study;
- archaeological and cultural assessment;
- noise study;
- electromagnetic field (EMF) assessment;
- traffic analysis;

- layouts and elevation plans; and
- landscaping and fencing plans.

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

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

### **1.5.5 Public Consultation Strategy**

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

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

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

### **1.5.6 Project Implementation**

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

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

### **1.5.7 Project lead times**

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

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

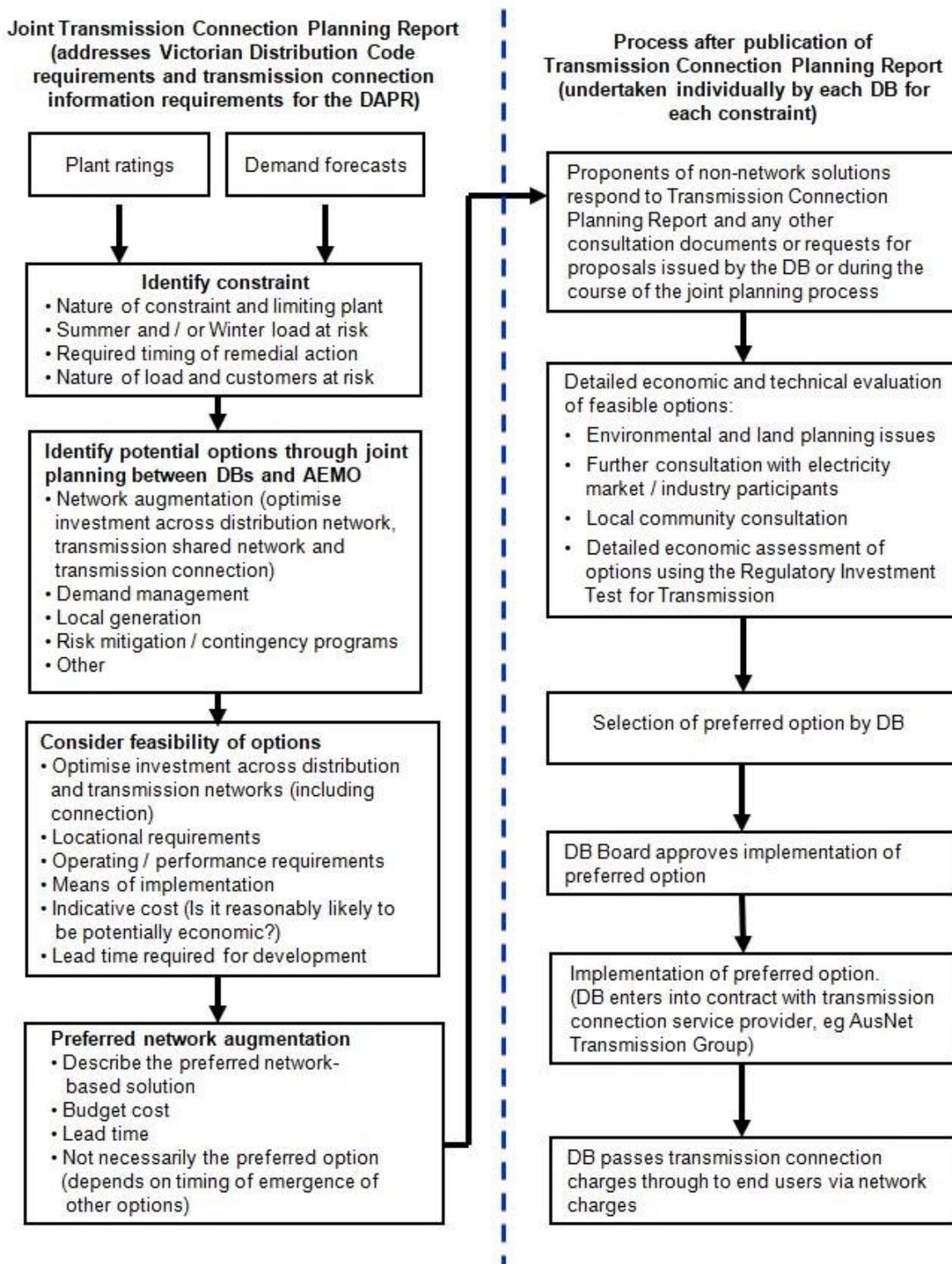
- Finalisation of any requirements for shared network augmentation due to planned connection asset augmentation works. These requirements are assessed through the joint planning process, which involves AEMO, AusNet Transmission Group and the DBs in Victoria.
- Procurement of a planning permit in relation to the proposed works. In order to obtain planning consent for proposed works, the statutory planning requirements of the local council(s) must be met, and community expectations must be addressed. For connection asset augmentations involving either major augmentations on an established site or the development of new terminal station(s) on new site(s), a period of at least 24 to 36 months is required for land planning and associated community issues to be resolved. The timely completion of this task requires effective coordination and cooperation between AEMO, AusNet Transmission Group and the DBs through the joint planning process in Victoria.
- After completing the above two tasks successfully, the next important tasks are:
  - finalisation of the scope of works;
  - preparation of cost estimates (including invitation to tender if the project is contestable); and
  - finalisation and execution of all contracts and agreements between distribution and transmission network service providers after obtaining all the necessary internal business approvals.

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

## 1.6 Overview of Transmission Connection Planning Process

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

### PROCESS FLOW CHART: TRANSMISSION CONNECTION PLANNING



## 2 PLANNING STANDARDS

### 2.1 Planning standard applying to transmission connection assets

Clause 3.4.2(c) of the Victorian Electricity Distribution Code requires this report to set out the planning standards applying to transmission connection assets. The planning standard applied by the DBs is the Regulatory Investment Test for Transmission (RIT-T), the purpose of which is set out in clause 5.16.1(b) 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 to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action or the provision of inertia network services required under clause 5.20B.4 or the provision of system strength services required under clause 5.20C.3.”

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

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

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

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

Under the definition contained in the Rules, “applicable regulatory instruments” in Victoria include:

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

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

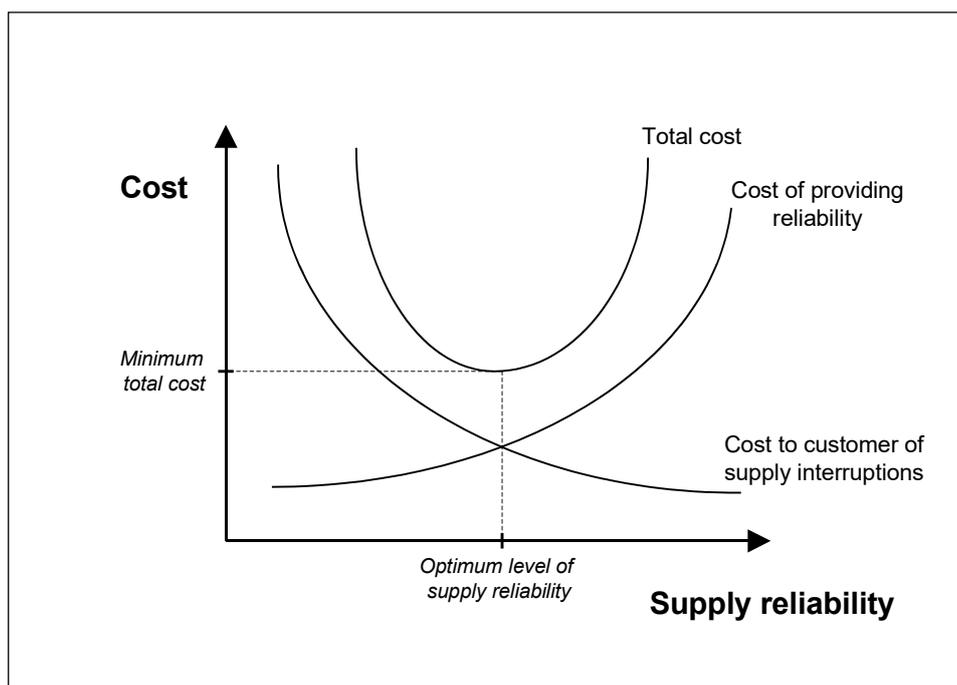
## 2.2 Overall objective of transmission connection planning

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

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

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

**Figure 2: Balancing the direct cost of service and the indirect cost of interruption**



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

## 2.3 Overall approach to transmission planning and investment evaluation

In Victoria, pursuant to section 50C of the National Electricity Law, AEMO applies a probabilistic approach<sup>18</sup> to planning the shared transmission network<sup>19</sup>.

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

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

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

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

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

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

## 2.4 VCR: Valuing supply reliability from the customers’ perspective

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

<sup>18</sup> 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](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf)

<sup>19</sup> As explained in section 1, the “shared transmission network” is the Victorian transmission system, excluding the transmission facilities that connect the distribution networks (and the generators) to the high voltage network. The distribution businesses are responsible for the planning and development of the transmission facilities that connect their distribution networks to the shared transmission network. These arrangements are set out in the distribution licences issued by the ESC.

Estimating the marginal value to customers of reliability is inherently difficult, and ultimately requires the application of some judgement. Nonetheless, there is information available (principally surveys designed to estimate the costs faced by customers from electricity supply interruptions) that provides a guide to the likely value.

In September 2014, AEMO published its final report on its 2013-2014 review of the Value of Customer Reliability (VCR). AEMO conducted the review at the request of the former Standing Council on Energy and Resources (SCER), now the Council of Australian Governments' (COAG) Energy Council. AEMO's final report explained that<sup>20</sup>:

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

AEMO's final report summarised its findings as follows<sup>21</sup>:

"AEMO's assessment of the survey findings includes the following:

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

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<sup>20</sup> AEMO, Value of Customer Reliability Review Final Report, September 2014, page 6. The report is available from AEMO's website at the following address:  
<http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review>

<sup>21</sup> Ibid, page 1.

In December 2014, AEMO published its final Application Guide on the VCR<sup>22</sup>. Section 5 of the Application Guide explains that:

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

Table 1 below shows the 2018 VCR estimates obtained by applying the annual indexation adjustment (set out in section 5.2 of the VCR Application Guide) to AEMO's sector and composite VCR estimates for 2014 (as set out in AEMO's September 2014 VCR Review Final Report).

**Table 1: VCR estimates by sector for 2018**

<b>Sector</b>	<b>VCR for 2017 (\$/kWh)</b> (Source: AEMO's September 2014 VCR Review Final Report, adjusted for annual indexation in accordance with s.5.2 of AEMO's December 2014 VCR Application Guide)
Residential (Victoria)	26.45
Commercial (NEM)	47.77
Agricultural (NEM)	50.93
Industrial (NEM)	47.07 <sup>23</sup>
<b>Composite- all sectors</b>	<b>42.20</b>

The DBs note that the indexation adjustment results in a 1.9% increase in the VCR from 2017 to 2018

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

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

- AEMO's previous VCR estimate of approximately \$69.30 per kWh (expressed in 2018 dollars), which was based on the 2007-08 VENCORP study<sup>24</sup>;

<sup>22</sup> . The Application Guide is available at: <http://www.aemo.com.au/-/media/Files/PDF/VCR-Application-Guide--Final-report.pdf>

<sup>23</sup> Excludes industrial customers that are directly connected to the transmission network.

- Oakley Greenwood's 2012 estimate of the New South Wales VCR<sup>25</sup>, of approximately \$106 per kWh (expressed in 2018 prices); and
- AEMO's 2018 Victorian VCR estimate of \$42.20 per kWh.

The wide range of VCR estimates produced by these three studies is likely to reflect estimation errors and methodological differences between the studies, rather than changes in the actual value that customers place on reliability<sup>26</sup>. Moreover, the magnitude of the reduction in AEMO's VCR estimates raises concerns that the investment decisions signalled by applying the most recent VCR estimate may fail to meet customers' reasonable expectations of supply reliability.

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

The DBs' approach to the VCR is consistent with the AER's latest guidance on how the VCR should be applied in RIT-Ts, which emphasises the importance of using reliable, trusted VCR values from an independent source, and subjecting those values to scenario and sensitivity analysis<sup>27</sup>. In applying the VCR, it is also important to recognise that VCR is a composite (or weighted average) measure of customer interruption costs:

- for a wide range of different customers; and
- across a wide range of supply interruption attributes including time of day, duration, frequency, and season.

The range of sector VCR values has potentially significant implications for transmission connection investment decisions, especially where the composition of the load supplied from a constrained terminal station is dominated by a particular sector. These considerations suggest there is a case for applying sector-specific VCR values in transmission connection investment analysis, where a constraint affects a readily identifiable group of consumers. It may also be appropriate to calibrate the VCR estimate to take into account the outage scenario, as noted by AEMO<sup>28</sup>:

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

<sup>24</sup> See section 2.4 of the Victorian DB's 2013 Transmission Connection Planning Report.

<sup>25</sup> AEMO, Value of Customer Reliability Review Appendices, Appendix G, September 2014.

<sup>26</sup> A further source of differences in the composite VCR estimates is the estimated composition of load by sector.

<sup>27</sup> AER, Explanatory statement, Draft revisions of the application guidelines for the regulatory investment tests, July 2018, section 6.9, page 36.

<sup>28</sup> AEMO, Value of Customer Reliability - Application Guide, Final Report, December 2014, page 9.

a connection point, customer class VCRs are re-weighted by removing off-peak outage scenarios and changing peak demand scenario probabilities.

For example, consider a 22 kV underground feeder which serves residential customers only. Based on historical data, outages on this part of the network mainly occur during peak demand periods, with few occurring at other times. Further, most outages are restored within three hours. Here it may be appropriate to re-weight the VCR based on revised outage probabilities that reflect actual outage times and durations.

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

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

On 5 July 2017, the AEMC released its final Rule determination on the VCR (following a Rule change request from the COAG Energy Council). Under the new Rule, which came into effect on 13 July 2018:

- The AER will be responsible for developing and publishing a VCR methodology and VCR estimates.
- The AER must conduct a review of the VCR estimation methodology every 5 years and publish updated VCR estimates following each review.
- As part of the VCR methodology, the AER must also specify a method for adjusting the VCR on an annual basis.
- By 31 December 2019, the AER must complete its first review of the VCR methodology and publish the VCR estimates.

The Rule change does not affect the VCR for the purpose of this 2018 Transmission Connection Planning Report. As key stakeholders, the DBs will participate in the VCR review, and will consider the future application of the VCR following the publication of the AER’s estimate.

## **2.5 Application of the probabilistic approach to transmission connection planning**

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

- the expected cost that will be incurred if no action is taken to address an emerging constraint,<sup>29</sup> and
- whether it is economic to augment terminal station capacity to reduce expected supply interruptions.

<sup>29</sup> The energy that would not be supplied in the event of an interruption is valued in accordance with the approach outlined in Section 2.4 above.

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

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

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

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

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes;
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand, and catastrophic plant failure leading to increased safety risk, increased risk of property damage, and/or extended periods of plant non-availability;
- the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk; and
- the Victorian DBs' obligation (under clause 5.2 of the Victorian Electricity Distribution Code) to use best endeavours to meet, among other things, reasonable customer expectations of reliability of supply.

### 3 CURRENT AND EMERGING PLANNING CONSIDERATIONS

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

#### 3.1 Electricity market changes, and the emergence of embedded generation

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

The changes include:

- a decline in market-wide electricity consumption from historically high levels, with minimal growth in consumption expected over the medium term<sup>30</sup>;
- increased variability in peak demand growth rates across regions, with some regions exhibiting comparatively strong demand growth, and other regions exhibiting very low or in some cases negative demand growth;
- increased prominence of distributed and renewable generation at both the consumer side of the supply chain (for example, residential solar panels) and in the wholesale generation market (for example, large scale wind and solar farms connecting to distribution networks); and
- the development of other technologies that enable consumers to generate and store their own electricity.

In July 2018, AEMO published its first Integrated System Plan (ISP), which is a cost-based engineering optimisation plan that forecasts the overall transmission system requirements for the NEM over the next 20 years. The ISP provides the foundation for a robust, least-cost path for the NEM to adapt to and accommodate the rapid and transformative changes occurring in the energy sector. The ISP is therefore an important development in the national planning arrangements that will shape future investments in transmission and generation capacity.

In Victoria, the State Government has legislated<sup>31</sup> its Victorian Renewable Energy Targets (VRET), which require 25 per cent of electricity generated in Victoria to come from renewable energy sources by 2020 and 40 per cent by 2025. The Victorian Government has also established the Victorian Renewable Energy Auction Scheme (VREAS) to support the achievement of these targets.<sup>32</sup> The VREAS auction held in

<sup>30</sup> AEMO's March 2018 update of its *Electricity Forecasting Insights for the National Electricity Market* states: "Consumption met by grid-supplied electricity is forecast to remain relatively flat for the next 20 years, despite projected 30% growth in population and projected growth in the Australian economy."

<sup>31</sup> The [Renewable Energy \(Jobs and Investment\) Act 2017 \(Vic\)](#).

<sup>32</sup> [https://www.energy.vic.gov.au/\\_data/assets/pdf\\_file/0022/80509/VRET-fact-sheet-Bill.pdf](https://www.energy.vic.gov.au/_data/assets/pdf_file/0022/80509/VRET-fact-sheet-Bill.pdf)

2017 will deliver up to 650 MW of new large scale renewable energy generating capacity to help meet Victoria's energy supply needs.

On 14 September 2018, the Victorian government announced that eligible Victorian households who installed solar panels on or after 19 August can apply for a rebate to cover half the cost, up to a maximum of \$2225. The government's media release stated that over 10,000 people registered their interest in rebates in the three weeks since the program was announced. It also noted that 10,000 homeowners installing 4kW solar systems would add 40 MW of new solar power to the grid.<sup>33</sup>

AEMO's 2018 Victorian Annual Planning Report confirmed that the level of renewable generation penetration is expected to increase in Victoria, as the generation mix changes due to the VRET. The majority of renewable generation connection interest is in western Victoria. AEMO is progressing the Western Victoria Renewable Integration Regulatory Investment Test for Transmission (RIT-T), which seeks to increase the capability of the western Victoria power system, and reduce congestion associated with the projected new generation in that region.

In recent years, the significant increase in connection applications for renewable generation has given rise to the need for the DBs' transmission connection planning activities to include:

- analysis and management of voltage compliance issues associated with the connection of new low carbon generation to the distribution network;
- specifying connection requirements and operating the distribution system to ensure that generating stations remain stable and connected during system disturbances;
- determining the design specifications for new transformers so that any new plant installed enables the efficient mitigation of emerging voltage management issues; and
- assessing the impacts of possible reverse power flows through transmission connection assets<sup>34</sup>.

The DBs will continue to monitor the changing role of the network and the increasing contribution from distributed generation, as well as on-going energy policy developments at both the State and national levels. Our aim is to undertake our transmission connection planning activities so as ensure that the network continues to provide cost effective and reliable services that meet the needs of all users, including low carbon generators.

## **3.2 Issues arising from increased embedded generation**

### **3.2.1 Transformer ratings**

Recent increases in the amount of committed and forecast new intermittent embedded generation are expected to lead to significant reverse power flows through some terminal station transformers. Reverse flows associated with substantial intermittent generation output may result in significantly increased variability of transformer loadings, increased

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<sup>33</sup> Victorian government media release at:  
<https://www.premier.vic.gov.au/wp-content/uploads/2018/09/180914-Applications-Now-Open-For-Half-Price-Solar-Panel-Rebates.pdf>

<sup>34</sup> Section 3.2 provides further information on the challenges arising from reverse power flows.

transformer utilisation, and reduced time for transformers to cool down between periods of high loading.

AusNet Transmission Services has advised that in these circumstances, the existing cyclic ratings may no longer be applicable to these transformers because they no longer exhibit a predictable cyclic loading pattern. Instead, it may be necessary to adopt the transformer's name plate rating (rather than the higher cyclic rating) for planning and operational purposes.

AusNet Transmission Services reviews transformer load profiles on an ongoing basis and will update applicable ratings as required. With some transformers expected to be increasingly affected by significant reverse flows, it is expected that some ratings will be reduced in the near future, which could result in potentially significant increases in load at risk at the affected stations. It is noted that some of the increased load at risk would likely be offset by the output from intermittent generation. However, it is also noted that deriving forecasts of intermittent generator output is complex, and particularly challenging given the limited data available to forecast that output at times of high demand.

In advance of the completion of AusNet Transmission Services' review of transformer ratings at the affected stations, the Risk Assessments in this 2018 report continue to adopt each station's current cyclic rating.

### **3.2.2 Impact of rooftop PV on estimates of energy at risk**

As noted above there has been an increasing prominence of distributed generation at the consumer end of the supply chain, in particular rooftop solar photovoltaic generation (rooftop PV). Rooftop PV has the impact of reducing the energy consumption as seen by the grid, and to a lesser degree<sup>35</sup>, the maximum demand at the transmission connection points.

The DBs account for this impact on maximum demand in their demand forecasts. It is these forecasts, of customer load with the generation output of rooftop PV netted off, that are used to assess the amount of energy at risk and expected unserved energy at each transmission connection point.

It is noted however, that 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). Under the current forecasting approach, estimates of energy at risk do not take this effect into account and as a consequence the amount of unserved energy due to a network outage may be underestimated by an amount equal to the energy contribution that would have been made by PV panels for the duration of the interruption.

An assessment of the impact of this issue has been carried out. It has been estimated that the average impact on the energy at risk across all Victorian transmission connection points is approximately 2% to 3%. However the impact may be more significant at different transmission connection points depending on the installed capacity of rooftop PV in a particular supply area, and the time of day that the maximum demand occurs for the transmission connection point. In some cases the impact may be as much as 10% to 15%.

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<sup>35</sup> 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.

For simplicity, and due to the relatively low average materiality of this issue, for the purpose of this 2018 report the DBs have maintained the current forecasting approach. However, for a Regulatory Investment Test for Transmission (RIT-T) assessment, the DBs will consider this impact and include it in the assessment (where material) in order to obtain a more accurate estimate of energy at risk.

### **3.2.3 Minimum demand and voltage management**

Networks have been designed and operated with a focus on one-way power flow because, traditionally, electricity was centrally generated and transmitted through the transmission network and connection asset transformers, and then consumed throughout the distribution network.

The design relied on the fact that voltage levels would gradually and predictably drop from the generation source, and then be boosted back up via appropriately tapped transformers and strategically located reactive support, until it reached the consumer. With these operational characteristics in mind, transformers were designed and purchased for a particular voltage profile and traditionally have a high boost, low buck tapping range. This means they are highly capable of raising (boosting) voltage from the high voltage side to the low voltage side, but have a very limited ability to drop (buck) the voltage down.

The recent prominence of embedded generation is proving that this traditional network design and operational philosophy is increasingly inadequate to meet future needs. As the penetration of embedded generation increases and offsets demand, the minimum demand at a number of stations is declining. This declining minimum demand results in higher voltage levels on the distribution side, requiring more capability from transformers to lower voltage levels during times of minimum demand, rather than raising voltage levels. The management of voltage is made more challenging by the fact that demand at many stations is still growing, so the disparity between peak and minimum demand is increasing and the voltage band to be managed throughout the day is widening.

Similarly, the increased disparity between minimum and maximum demand is also resulting in a wider range of fault levels that the network protection systems need to be able to recognise and operate for. As with the design of transformers, the protection systems were not designed with such wide operating bands in mind.

In addition to the increased challenges of maintaining voltage levels within acceptable limits, AEMO recently identified, in its Integrated System Plan (ISP)<sup>36</sup>, low system strength as an emerging issue driven by increased penetration of non-synchronous generation. System strength not only relates to maintaining voltage levels within acceptable limits, as previously described, but extends to the power system's ability to remain stable under normal conditions and to return to a steady state condition following a system disturbance.

It is noted that this 2018 Transmission Connection Planning Report does not contain minimum demand forecasts for terminal stations. So, while the impact of declining minimum demand levels on connection assets is not yet fully understood, it is expected that additional reactive support, provided by NSPs and newly connected embedded generation, will be required to adequately manage voltages within the capabilities of the existing assets.

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<sup>36</sup> [https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/ISP/2018/Integrated-System-Plan-2018\\_final.pdf](https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf)

Additionally, any new or replacement connection assets installed in the future may be required to meet new standards to ensure the assets are capable of operating in the wider voltage and fault level ranges expected at that location. For example, connection asset transformers may require designs with wider tap ranges and/or more buck voltage capability to allow for the increased penetration of embedded generation driving lower minimum demand or reverse power flows through the transformers. In addition, current transformers may require similarly wider operating ranges to ensure they can identify and operate for the wider fault level ranges being exhibited.

### **3.2.4 The need for generation runback schemes**

At terminal stations where significant embedded generation is currently and/or forecast to be connected, power flows from the generation source(s) may lead to an increased risk of terminal station transformer overloading. Under the connection arrangements in the National Electricity Rules<sup>37</sup>, the embedded generator is required to pay the costs of providing the connection services, including the costs of augmenting connection assets.

In some cases, the connecting generator may determine that it is uneconomic for conventional network 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 quickly reduce the amount of generation inflows, to ensure that distribution and transmission plant loadings are maintained within safe limits, and the connection services provided to load customers are not adversely affected by the connection of embedded generation.

## **3.3 Management of system fault levels**

As noted above, there have been significant changes in the mix of generation in the Victorian power system, and across the National Electricity Market over recent years. These changes are expected to continue. The increasing proportion of non-synchronous generation (both large-scale and distributed) creates a number of operational challenges. One such challenge is the management of changing fault levels<sup>38</sup> across the power system.

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

- further increases in the connection of new low carbon generation to the network, driven by, amongst other things, the Victorian Renewable Energy Target; and
- the possible development of increased interconnector capacity.

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

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<sup>37</sup> Clauses 5.3 and 5.3A.

<sup>38</sup> In an electric power system, a fault or fault current is any abnormal electric current. For example, a short circuit is a fault in which current bypasses the normal load. In power systems, protective devices detect fault conditions and operate circuit breakers to protect an electrical circuit from damage caused by overload or short circuit. In order for a circuit breaker to operate safely and reliably, the current that flows in the event of a fault must be within the rating or short-circuit limits of the circuit breaker and other terminal station equipment.

### **3.4 Managing the risk of transformer failure**

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

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

### **3.5 Maintaining security of supply during major terminal station renewals**

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

AusNet Transmission Group's asset renewal plan provides details of the work that is planned for the next ten years. The report can be downloaded from AEMO's website at: [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/VAPR/2018/AusNet-Services-asset-renewal-plan-2018.pdf](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2018/AusNet-Services-asset-renewal-plan-2018.pdf).

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

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

## 4 HISTORIC AND FORECAST DEMAND

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

The demand forecasts used in the preparation of this report are referred to as the Victorian Terminal Station Demand Forecasts (TSDF). The TSDF report is prepared by the Victorian DBs, and is published alongside this Transmission Connection Planning Report.

As noted in last year's Transmission Connection Planning Report, AEMO commenced publishing a separate connection point forecast report for Victoria in 2014. AEMO's forecasts are derived from State-based aggregate demand forecasts. A copy of AEMO's 2018 Victorian Connection Point Forecasting Report is available from its website at:

<http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting/Victoria>

It is noted that there are some differences between the demand forecasts in the DBs' TSDF and AEMO's Victorian connection point forecasts. These differences primarily reflect:

- different approaches to weather normalisation, which result in the two sets of forecasts adopting different starting points for some terminal stations; and
- AEMO's approach to State-wide demand forecasts and its reconciliation of these to individual terminal station forecasts, which results in different forecast demand growth rates being adopted by AEMO for some terminal stations, compared to the growth rates adopted in the TSDF.

As in previous years, the DBs consider it appropriate to continue to adopt the TSDF forecasts for the purpose of preparing this Transmission Connection Planning Report. It is noted that the TSDF forecasts have been applied in all previous Transmission Connection Planning Reports.

## 5 RISK ASSESSMENT AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS

### 5.1 Preamble

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

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

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

In addition, capital expenditure is required from time to time to address fault level issues. This expenditure is driven chiefly by mandatory health and safety standards, and does not relate to terminal station capacity, per se. Fault level issues are therefore not within the scope of this report, however, the analysis of feasible and preferred options for increasing capacity will, where appropriate have due regard to issues relating to fault level control<sup>39</sup>.

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

- **Energy at risk:** For a given demand forecast, this is the amount of energy that would not be supplied from a terminal station if a major outage<sup>40</sup> of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.6 months (as discussed in section 5.4 below), and no other mitigation action is taken. This statistic provides an indication of the magnitude of loss of load that would arise in the unlikely event of a major outage of a transformer.
- **Expected unserved energy:** For a given demand forecast, this is the energy at risk weighted by the probability of a major outage of a transformer. A load duration curve is used to estimate the unserved energy in each hour of the year for a major transformer outage. The estimated unserved energy for each hour is then multiplied by the probability of the outage occurring in any hour of the year. The total expected unserved energy in a year is obtained by summing the probability-weighted estimates of unserved energy for each hour of the year. This statistic provides an indication of the amount of energy, on average, that will not be supplied in a year, taking into

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<sup>39</sup> Some non-network alternatives such as embedded generation may raise issues relating to fault level control. A further discussion of this issue is set out in Section 1.4 of this report.

<sup>40</sup> The term "major outage" refers to an outage that has a mean duration of 2.6 months, typically due to a significant failure within the transformer. The actual duration of an individual major outage may vary from under 1 month up to 9 months. Further details are provided in section 5.4 below.

account the very low probability that one transformer at the station will not be available for 2.6 months because of a major outage.

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

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

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

In interpreting the information set out in this report, it is important to recognise that in the case of a Summer peaking station, the 50<sup>th</sup> percentile demand forecast relates to a maximum average temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50% probability of being higher than the 50<sup>th</sup> percentile demand forecast.<sup>41</sup>

## 5.2 Interpreting “energy at risk”

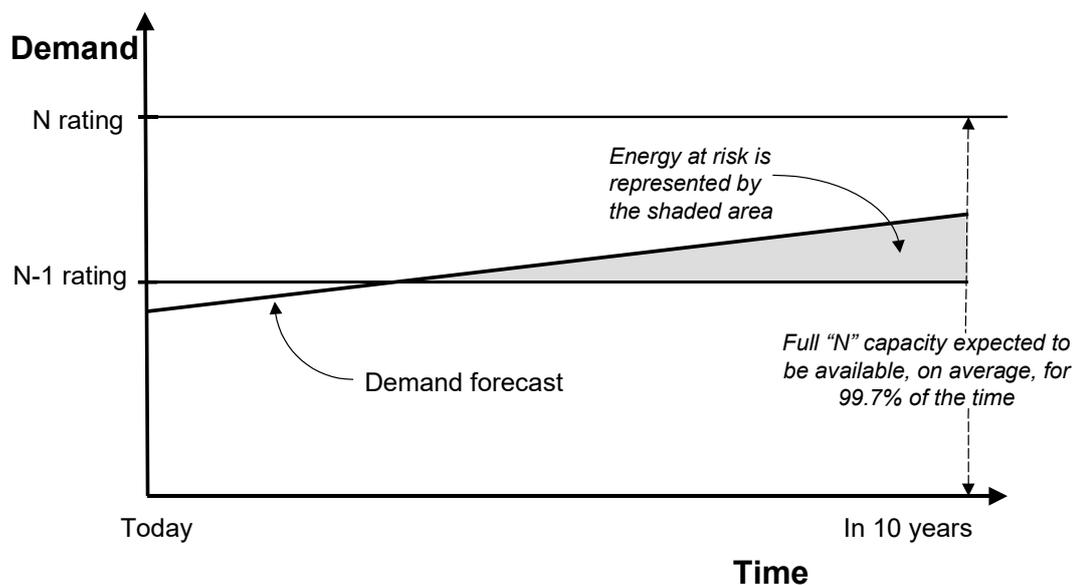
As noted above, “energy at risk” is an estimate of the amount of energy that would not be supplied if one transformer was out of service due to a major failure during the critical loading season(s), for a given demand forecast.

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

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<sup>41</sup> Conversely, there is also a 50% chance that actual demand will be lower than the forecast in any one year.

## Relationship between N rating, N-1 rating and energy at risk



### 5.3 Assessing the costs of transformer outages

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

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

In estimating the expected cost of connection plant outages, this report considers the first order contingency condition (“N minus 1”) only. It is recognised that in the case of terminal stations that consist of two transformers, there is a significant amount of energy at risk if both transformers are out of service at the same time, due to a major outage.

The DBs have carefully considered whether this report should be expanded to include consideration of 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 is that the value of expected unserved energy associated with second order contingencies would be unlikely to be sufficiently high to justify the advancement of any major augmentation, compared to the augmentation timing that is economically justified by an analysis that is limited to considering first order contingencies. The Appendix contains a detailed example which illustrates this point.

### 5.4 Base reliability statistics for transmission plant

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

- the availability of the connection point main transformers; and

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

The basic reliability data adopted for the purpose of producing this report is summarised in the following table.

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	2.6 months	On average, 2.6 months is required to repair the transformer and return it to service, during which time, the transformer is not available for service.
Expected transformer unavailability due to a major outage per transformer-year	$0.01 \times 2.6/12 = 0.217\%$ approximately	On average, each transformer would be expected to be unavailable due to major outages for 0.217% of the time, or 19 hours in a year.

In August 2018, AusNet Services' Principal Engineer, Strategic Network Planning confirmed that the transformer outage rate data and the average transformer repair time assumptions shown in the above table are reasonable for the purpose of preparing the transmission connection asset risk assessments<sup>42</sup>.

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.

## 5.5 Availability of spare transformers

In August 2018, 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.

<sup>42</sup> AusNet Transmission Group uses asset condition based failure risk information for asset replacement decisions. Joint planning is undertaken with the DBs to coordinate terminal station augmentation works with AusNet Transmission Group's replacement plans.

- Spare transformers held by AusNet Transmission Group may be used to support essential maintenance activities including refurbishment programs. Any transformer used in this way would no longer be available to replace a failed transformer.
- AusNet Transmission Group will aim to install a spare transformer to replace a unit that is subject to a long term outage within one calendar month. However, it is not possible to provide a guaranteed time for installation of the temporary replacement, because the particular circumstances of each transformer failure will determine the replacement timeframe.
- There is a small number of AusNet Transmission Group stations for which a stock of spare transformers is not held. These stations are the metropolitan 220/22 kV connection stations (being Ringwood, Brunswick, Richmond, West Melbourne and Brooklyn) and Wodonga 330/66/22 kV Terminal Station. For the metropolitan 220 kV 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 are likely to exceed one calendar month. In the case of Wodonga 330/66/22 kV Terminal Station, the energy at risk does not warrant the procurement of a dedicated spare transformer.

In the case of Deer Park Terminal Station (which is owned and operated by TransGrid), the total 10<sup>th</sup> percentile load at this two-transformer station is not expected to exceed the rating of a single transformer until 2023, at which time there is forecast to be 17.5 MWh of load at risk (at the 10<sup>th</sup> percentile temperature). It is therefore considered acceptable during the period prior to 2023 to operate the station without procuring further backup capacity. This approach is reviewed annually.

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

## 5.6 Treatment of Load Transfer Capability

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 are able to be made at 66 kV and/or 22 kV and lower voltage levels.

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

- There is no guarantee that capacity will be available at an adjacent terminal station to accept load transfers, due to uncertainty of the availability of transformation capacity at that station.
- The capability of the distribution network to affect load transfers is always changing. It will vary depending on network loading conditions and is usually at a minimum

during peak demand times. The transfer capability can also be adversely affected by any abnormal configurations which 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.

The one exception to this approach is Wemen Terminal Station, which is the only single transformer station considered in this report. Wemen was planned on the basis that some load transfer capability at 66 kV would be available to Red Cliffs Terminal Station (RCTS 66) in the event of a transformer outage at Wemen. Accordingly, the risk assessment for Wemen takes into account the load forecasts for RCTS 66 and an assessment of the post-contingent load transfer capability.

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

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

Set out on the following pages are the detailed risk assessments and a description of the options available for alleviation of constraints, for each individual terminal station. The assessments, by station, are set out in alphabetical order. For each station, the network augmentation requirements (if any) and the estimated annual costs of the augmentation works are identified.

We have adopted an annuity approach to estimating the annual costs, which means that the cost is constant throughout the estimated life of the asset, which is 45 years for the purpose of this report. The annualised cost calculation also assumes a real pre-tax discount rate of 4% and an annual operating cost that is 1% of the project's capital costs. Using these inputs, for the purpose of this report the annualised cost is estimated to be 5.8% 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 2022 to 2025 is less valuable today than one which defers a similar network augmentation from, say, 2019 to 2022. 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<sup>43</sup>. In view of this consideration, the individual risk assessment commentaries for each terminal station will:

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

## **5.8 Interpreting the dates shown in the risk assessments**

All charts and tables in the following risk assessments present data on a calendar year basis. However, the narrative within some of the risk assessments may refer to composite years; for instance “2019/20”, or “summer of 2019/20”.

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 2019/20, for instance), the peak would typically be expected to occur in the second year (in this example, 2020), and the relevant data for 2019/20 would be shown in the accompanying tables and charts as 2020.

## **5.9 Augmentations to facilitate embedded generation connections**

As explained in section 1.3.1, clause 14 of the Distribution Code requires the DBs to plan and direct the augmentation of transmission connection assets to meet their obligations to supply load customers, not embedded generators. While our planning obligations are limited to facilitating load, the DBs also recognise that it may be useful to identify opportunities to augment transmission connection assets to provide improved access for embedded generators. The risk assessments therefore comment on any such opportunities, where applicable, noting that the investment would either need to be financed by the embedded generators or satisfy the RIT-T.

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<sup>43</sup> 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:

	PROPORTION OF MAJOR FAILURES	MEAN OUTAGE DURATION
Costly Major Failures <sup>44</sup>	0.4 of failures	5.0 months
Other Major Failures	0.6 of failures	1.0 month

Mean duration of a major failure =  $(0.4 \times 5.0 \text{ months}) + (0.6 \times 1.0 \text{ month}) = 2.6 \text{ months}$

### 2. Sample of expected transformer unavailability calculation

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

Expected transformer unavailability due to major outage per transformer-year (Refer to Section 5.4 for the base reliability statistics)	A	0.217%
Number of transformers	B	2
<b>Expected unavailability of one transformer (probability of being in state N-1)</b>	<b>C=A*B</b>	<b>0.434%</b>
<b>Expected unavailability of both transformers (probability of being in state N-2)<sup>45</sup></b>	<b>D=A*A</b>	<b>0.00047%</b>

<sup>44</sup> The costly major failures are those that would result in repair costs greater than 2% of the replacement value of the failed transformer, with a relatively long duration of outage for repair.

<sup>45</sup> The coincident outages of two transformers are considered to be “independent events”. This means that the failure of one transformer is assumed to not affect the availability of the other.

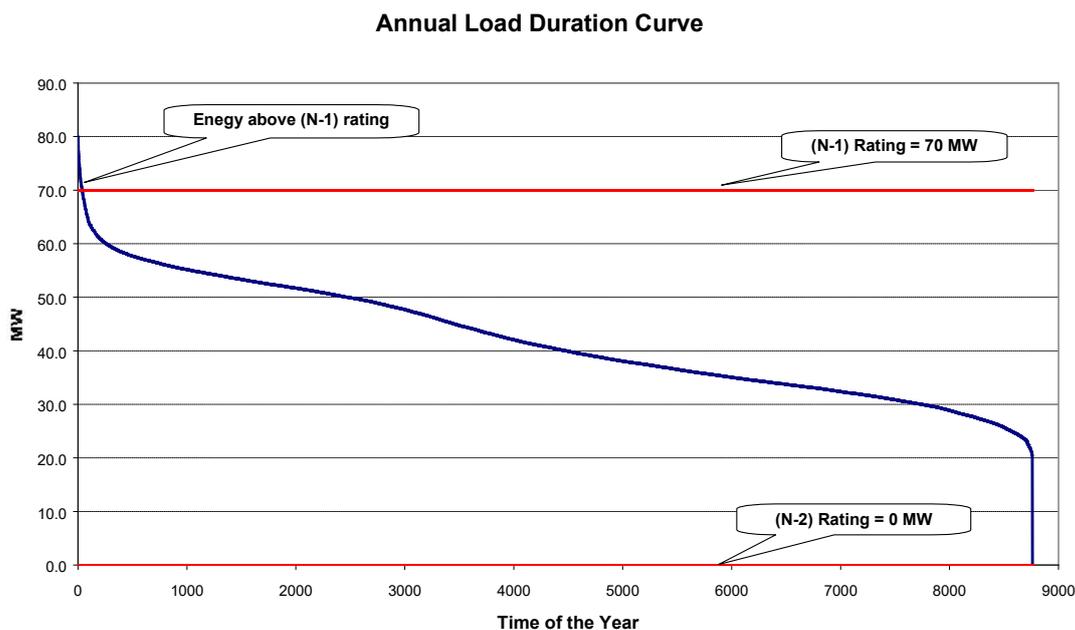
## Example Calculation

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

### Required Data:

- Maximum Demand = 80 MW
- (N-1) Rating = 70 MW
- (N-2) Rating = 0 MW
- Annual Maximum Demand Growth Rate = 3.0%
- Annual Energy Growth Rate = 1.5%
- VCR = \$60,000 per MWh<sup>46</sup>

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



### 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

<sup>46</sup> A VCR of \$60,000 per MWh is used for illustrative purposes only.

Similarly, energy at risk for an N-2 contingency is determined as the area below the load duration curve, but in excess of the N-2 rating:

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

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

$$\begin{aligned} \text{Expected Unserved Energy} &= (\text{Energy above N-1 Rating}) * (\text{N-1 Probability}) \\ &= (132 \text{ MWh}) * (0.434\%) = 0.6 \text{ MWh} \end{aligned}$$

$$\begin{aligned} \text{Customer Value} &= (\text{Expected Unserved Energy}) * (\text{VCR}) \\ &= (0.6 \text{ MWh}) * (\$60,000 \text{ per MWh}^{47}) = \$36,000 \end{aligned}$$

### Second Order Contingency (N-2)

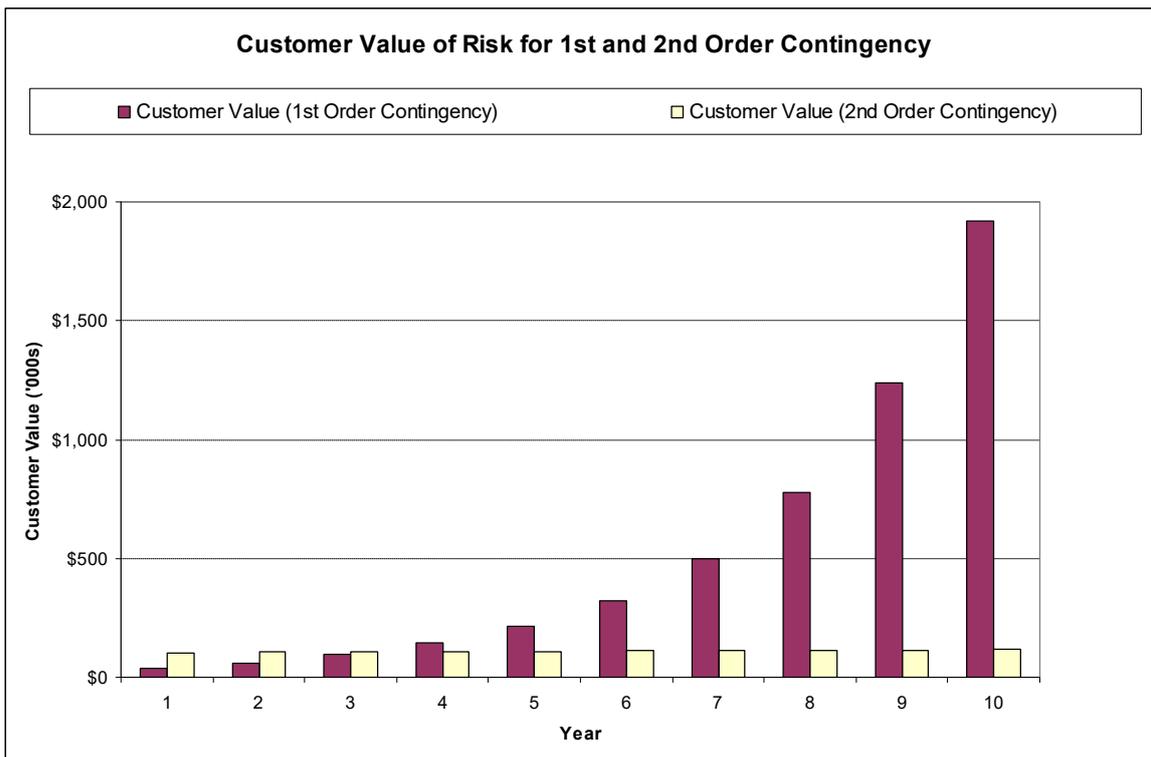
$$\begin{aligned} \text{Expected Unserved Energy} &= (\text{Energy above N-2 Rating}) * (\text{N-2 Probability}) \\ &= (367,877 \text{ MWh}) * (0.00047\%) = 1.7 \text{ MWh} \end{aligned}$$

$$\begin{aligned} \text{Customer Value} &= (\text{Expected Unserved Energy}) * (\text{VCR}) \\ &= (1.7 \text{ MWh}) * (\$60,000 \text{ per MWh}) = \$102,000 \end{aligned}$$

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

- The value of expected unserved energy for a 2<sup>nd</sup> order contingency is comparable to the value of expected unserved energy for a 1<sup>st</sup> order contingency in the earlier years (when the peak demand is roughly the same as the N-1 rating at the station). However, the combined total value of unserved energy for first and second order contingencies in those early years is highly unlikely to economically justify a large capital investment, such as the installation of a new transformer.
- Over the ten year planning horizon, the value of expected unserved energy for a 1<sup>st</sup> order contingency grows at a much faster rate than the value of expected unserved energy for a 2<sup>nd</sup> order contingency.
- The value of expected unserved energy associated with 2<sup>nd</sup> 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.

<sup>47</sup> A VCR of \$60,000 per MWh is used for illustrative purposes only.



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

## 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 66,903 customers. The stations supply both Jemena Electricity Network (37%) and Powercor (63%) customers.

ATS consists of three 150 MVA 220/66 kV transformers with the 2-3 66 kV bus tie circuit breaker locked open to manage fault levels. Under these arrangements, only one ATS 150 MVA 220/66 kV transformer operates in parallel with the BLTS system. BLTS has two 150 MVA 220/66 kV transformers supplying the BLTS 66 kV bus.

The existing synchronous condenser connected to the BLTS 66 kV bus was decommissioned in 2017 as it is no longer required.

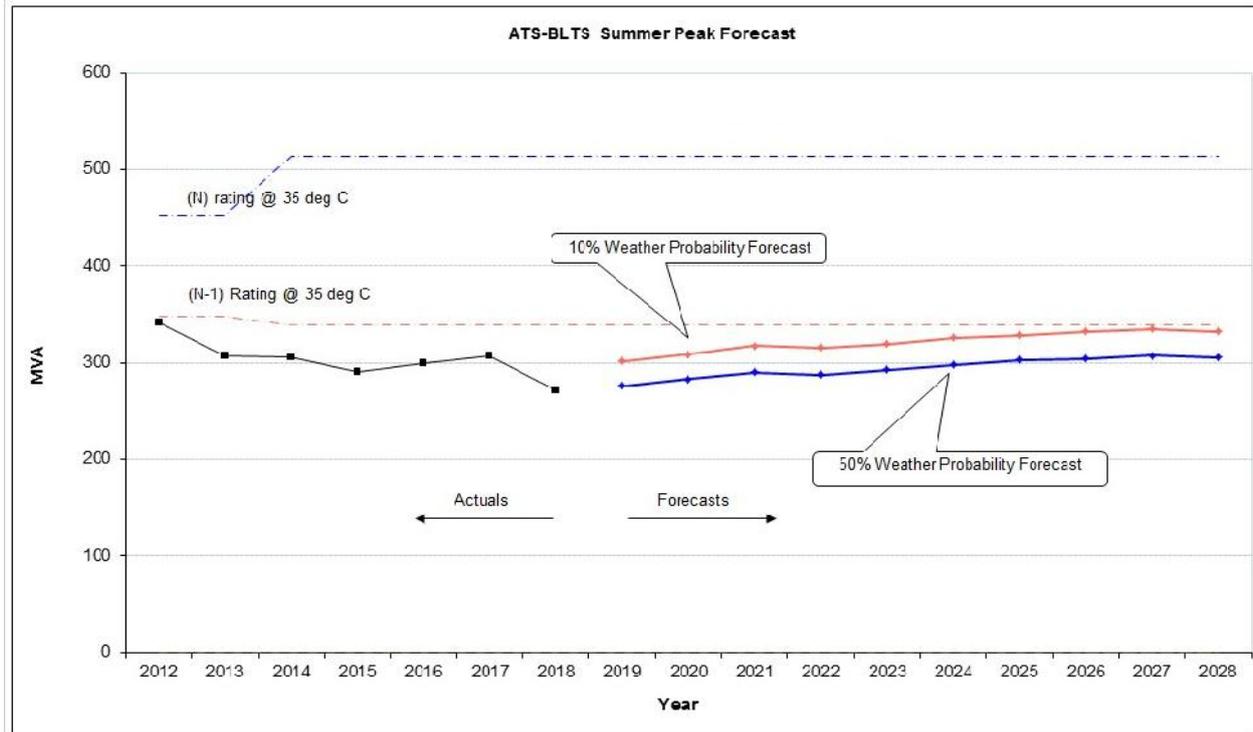
### **Magnitude, probability and impact of loss of transformer (N-1 System Condition):**

The load characteristic for ATS/BLTS substation is of a mixed nature, consisting of residential and industrial customers. The peak load demand on the entire ATS/BLTS 66 kV network reached 296.2 MW (307 MVA) in summer 2017. A major customer (Qenos) installed a 22.5 MW gas generator in January 2013 and load was reduced from ATS-BLTS due to the generation. This load reduction due to the generation is reflected in the load forecasts.

It is estimated that:

- For 19 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at the time of peak demand is 0.97.

The graph on the following page depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature. As explained above, the forecast is affected by the introduction of the Qenos embedded generator in summer 2012-13. Further, the completion of Deer Park Terminal Station in 2017 has enabled transfers away from the ATS-BLTS Terminal Station. In 2017 the BATS-BLTS tie was closed and 12 MW of load was transferred to Ballarat Terminal Station (BATS).



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

The graph shows there is sufficient capacity at the station to supply all expected demand at the 50<sup>th</sup> percentile and 10<sup>th</sup> percentile over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

## ALTONA WEST TERMINAL STATION (ATS West) 66 kV

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

### Background

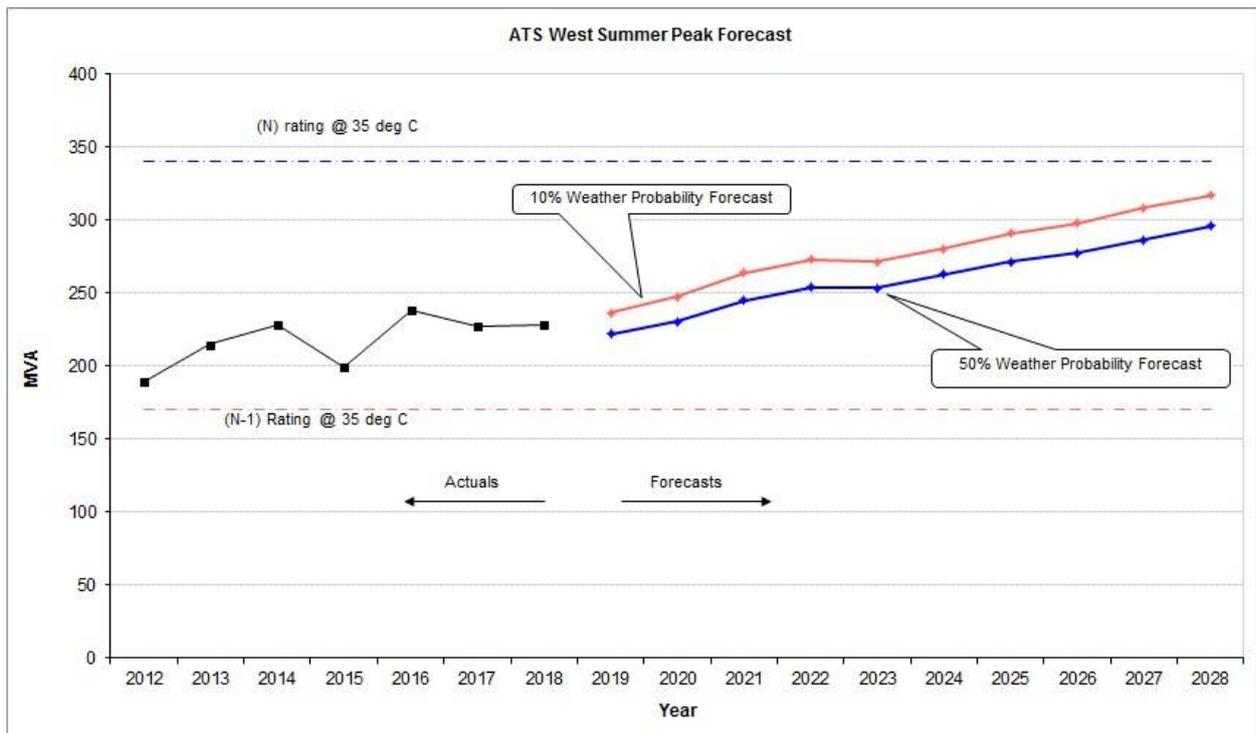
The ATS West 66 kV supply area includes Laverton, Laverton North, Altona Meadows, Werribee, Wyndham Vale, Mount Cottrell, Eynesbury, Tarneit, Hoppers Crossing and Point Cook. The station supplies 87,661 Powercor customers, as well as Air Liquide, a company supplied directly from the 66 kV bus at ATS. Air Liquide’s load has been included in the following assessment.

Growth in summer peak demand on the 66 kV network at ATS West has averaged around 1.8% per annum over last five years. The peak load on the station reached 216.9 MW in summer 2018.

It is estimated that:

- For 14 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at the time of peak demand is 0.95.

ATS West is summer peaking with high demand occurring over a five month period. The graph below depicts the 10th and 50th percentile summer maximum demand forecast together with the stations operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.

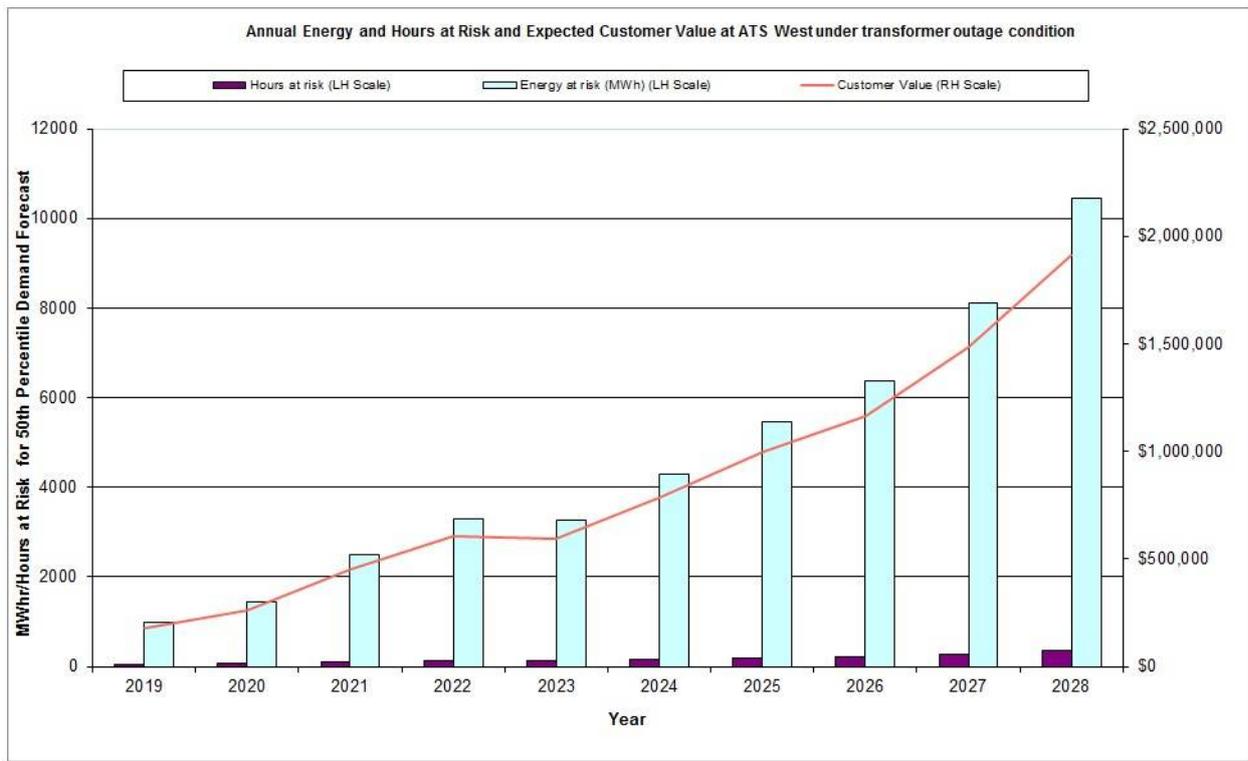


The “N” rating on the chart indicates the maximum load that can be supplied from ATS West with all transformers in service. The “N-1” rating on the chart is the load that can be supplied from ATS West with one 150 MVA transformer out of service.

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

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

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



**Comments on Energy at Risk**

For an outage of one transformer at ATS West 66 kV, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 176 hours in 2025. The energy at risk at the 50<sup>th</sup> percentile temperature under N-1 conditions is estimated to be 5,446 MWh in 2025. The estimated value to consumers of the 5,446 MWh of energy at risk is approximately \$229.6 million (based on a value of customer reliability of \$42,152/MWh)<sup>1</sup>. In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at ATS West in 2025 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$229.6 million.

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

<sup>1</sup> 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.

whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (5,446 MWh for 2025) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 23.6 MWh. This expected unserved energy is estimated to have a value to consumers of \$1.0 million (based on a value of customer reliability of \$42,152/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2025 is estimated to be 9,940 MWh. The estimated value to consumers of this energy at risk in 2025 is approximately \$419 million. The corresponding value of the expected unserved energy (of 43.1 MWh) is \$1.82 million.

These key statistics for the year 2025 under N-1 outage conditions are summarised in the table below.

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast under N-1 outage condition	5,446	\$229.6 million
Expected unserved energy at 50 <sup>th</sup> percentile demand under N-1 outage condition	23.6	\$1.0 million
Energy at risk, at 10 <sup>th</sup> percentile demand forecast under N-1 outage condition	9,940	\$419.0 million
Expected unserved energy at 10 <sup>th</sup> percentile demand under N-1 outage condition	43.1	\$1.82 million

It is noted that the chart on page 2 indicates that over the period from 2019 to 2028 inclusive, the value to consumers of the expected unserved energy in each year, for the 50<sup>th</sup> percentile demand forecast averages approximately \$840,000.

## **Possible Impact on Customers**

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

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

### N-1 System Condition

If one of the 150 MVA 220/66 kV transformers at ATS West is taken offline during peak loading times and the N-1 station rating is exceeded, the OSSCA<sup>2</sup> automatic load shedding scheme which is operated by AusNet Transmission Group's TOC<sup>3</sup> 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.

<sup>2</sup> Overload Shedding Scheme of Connection Asset.

<sup>3</sup> Transmission Operation Centre

Possible load transfers away to ATS/BLTS and DPTS terminal stations in the event of a transformer failure at ATS West total 15 MVA in summer 2019.

### **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 additional transformation capacity and reconfigure 66 kV exits at ATS, at an estimated indicative capital cost of \$18 million (equating to a total annual cost of approximately \$1.04 million per annum). This would result in the station being configured so that three transformers are supplying the ATS West load, and one transformer will continue to provide capacity to the ATS/BLTS system.
2. A new Tarneit zone substation is planned for 2023; however it is not a committed project at this point in time. This zone substation would be supplied from DPTS and will offload Werribee and Laverton zones substations in the order of 40 MW. This will not eliminate the load at risk at ATS West, only reduce it.
3. Demand reduction: There is an opportunity to develop innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of potential demand reduction depends on the customer uptake and would be taken into consideration when determining the optimum timing of any network capacity augmentation.
4. Embedded generation, connected to the ATS 66 kV bus, may substitute capacity augmentations.

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

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

On the basis of the present demand forecasts and applying the 2018 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 2025. As already noted, the chart on page 2 indicates that over the period from 2019 to 2028 inclusive, the value to consumers of the expected unserved energy in each year, for the 50<sup>th</sup> percentile demand forecast averages approximately \$840,000 when the 2018 VCR estimate is used. Applying the (higher) 2013 VCR estimate, the average annual expected unserved energy value at the 50<sup>th</sup> percentile demand forecast is approximately \$2.20 million per year over the period from 2019 to 2028 inclusive. At the higher VCR value, the preferred network option would be likely to be economically justified by around 2021.

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

## Altona West Terminal Station

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

Distribution Businesses supplied by this station:

Powercor (100%)  
MW MVA

Normal cyclic rating with all plant in service

Summer N-1 Station Rating:

Winter N-1 Station Rating:

	340
158	170
176	187

via 2 transformers (Summer peaking)

[See Note 1 below for interpretation of N-1]

Station: ATS West	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	222.1	230.6	245.2	254.0	253.6	263.1	271.8	277.7	286.5	296.1
50th percentile Winter Maximum Demand (MVA)	164.1	171.2	178.7	181.5	185.1	192.3	198.4	203.1	210.1	216.1
10th percentile Summer Maximum Demand (MVA)	236.5	247.9	264.3	273.0	271.7	280.8	291.0	298.1	308.8	317.2
10th percentile Winter Maximum Demand (MVA)	179.5	190.0	198.3	199.7	201.5	210.5	219.6	221.6	233.2	235.7
N-1 energy at risk at 50% percentile demand (MWh)	978	1436	2487	3302	3257	4300	5446	6378	8112	10454
N-1 hours at risk at 50th percentile demand (hours)	52.8	66.5	98.5	119.3	117.8	144.5	175.5	204.8	271.8	363.0
N-1 energy at risk at 10% percentile demand (MWh)	1817	2726	4480	5629	5473	7190	9940	11649	16762	19796
N-1 hours at risk at 10th percentile demand (hours)	78.5	105.3	154.5	181.5	181.8	254.5	378.5	429.5	619.8	700.8
Expected Unserved Energy at 50th percentile demand (MWh)	4.24	6.22	10.78	14.31	14.12	18.64	23.60	27.64	35.15	45.30
Expected Unserved Energy at 10th percentile demand (MWh)	7.87	11.81	19.41	24.39	23.71	31.16	43.07	50.48	72.63	85.78
Expected Unserved Energy value at 50th percentile demand	\$0.18M	\$0.26M	\$0.45M	\$0.60M	\$0.60M	\$0.79M	\$0.99M	\$1.17M	\$1.48M	\$1.91M
Expected Unserved Energy value at 10th percentile demand	\$0.33M	\$0.50M	\$0.82M	\$1.03M	\$1.00M	\$1.31M	\$1.82M	\$2.13M	\$3.06M	\$3.62M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$0.22M	\$0.33M	\$0.56M	\$0.73M	\$0.72M	\$0.94M	\$1.24M	\$1.45M	\$1.96M	\$2.42M

Notes:

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

(see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))

## 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 70,707 customers in Ballarat and the surrounding area. The station supply area includes Ballarat CBD and Ararat via the interconnected 66 kV tie with Horsham Terminal Station (HOTS).

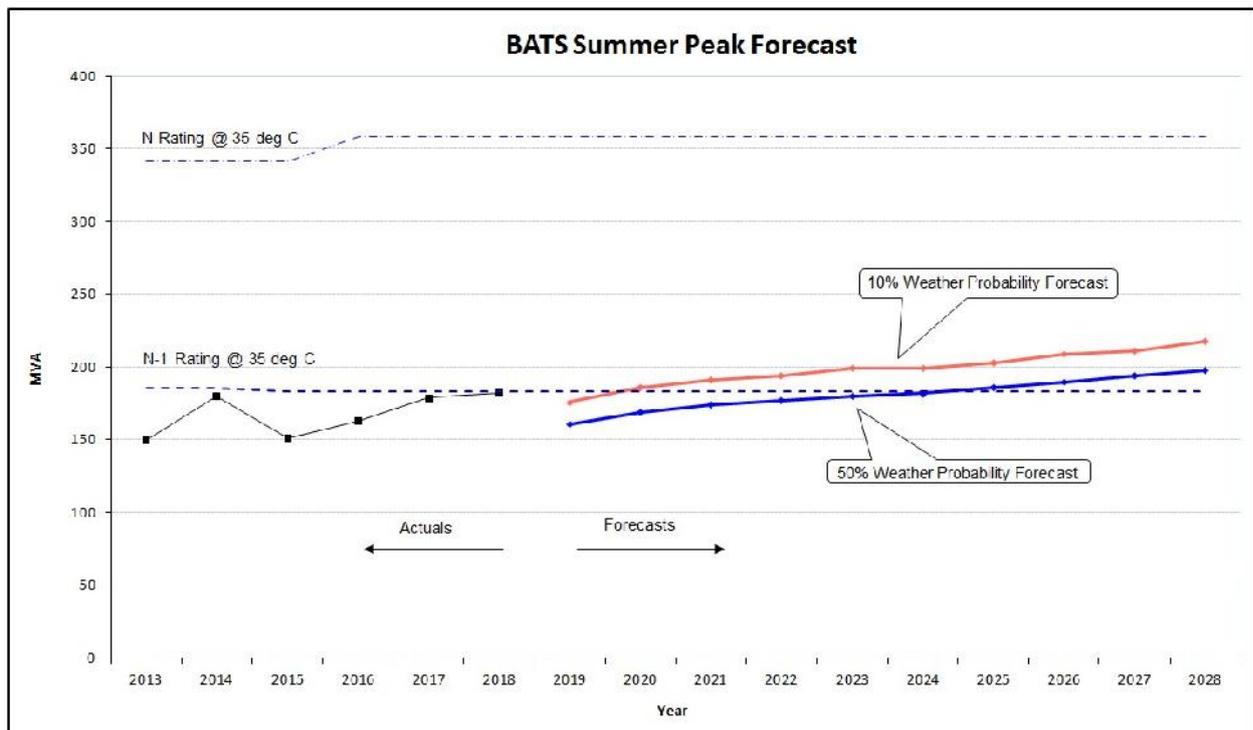
### Magnitude, probability and impact of loss of load

In 2015, one of the 150 MVA transformers failed at BATS. AusNet Transmission Group replaced the failed transformer with the 150 MVA country spare transformer. Accordingly, the station ratings have changed, and these changes are depicted in the graph below. Growth in summer peak demand at BATS has averaged around 6.4 MVA(4.7%) per annum over the last 5 years. The peak load on the station reached 177.3 MW (181.7 MVA) in summer 2018.

It is estimated that:

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

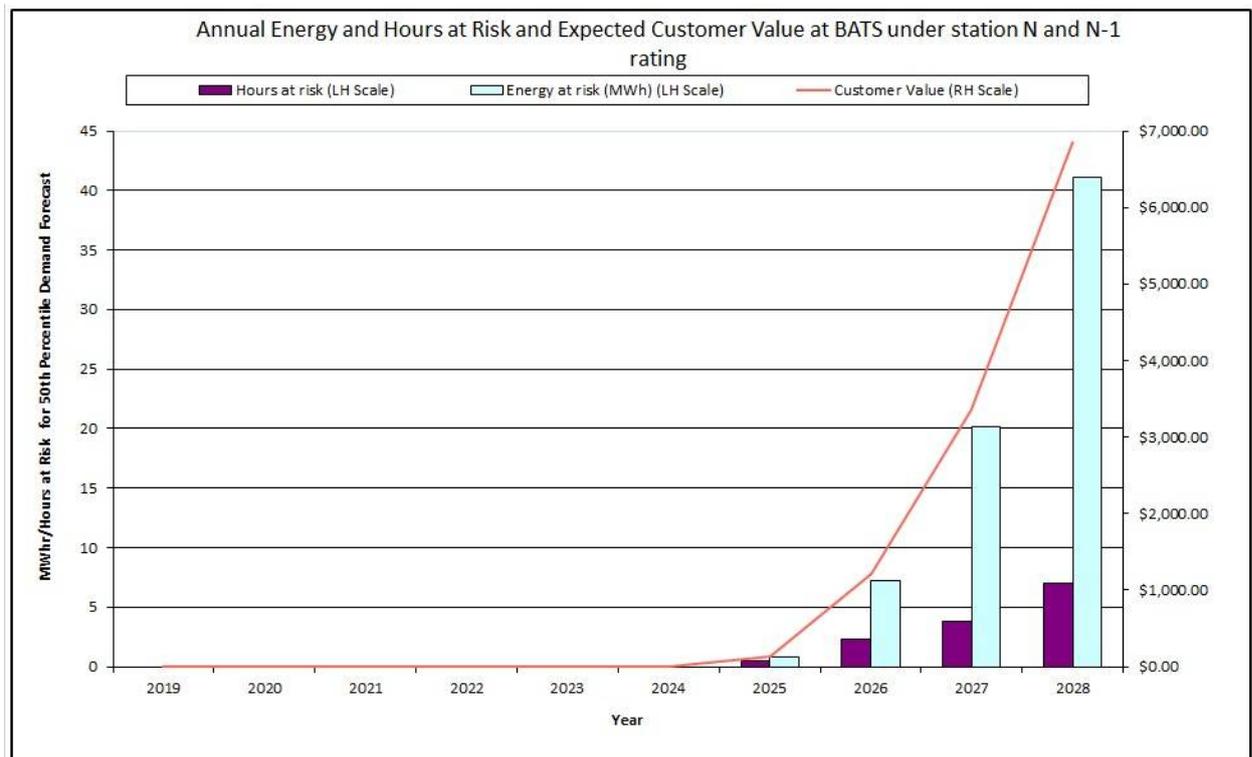
The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile maximum demand forecasts together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.



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

The graph above shows that there is sufficient capacity to supply the forecast demand at 50<sup>th</sup> percentile temperatures at BATS until 2025 if a forced outage of a transformer occurs.

The bar chart below depicts the energy at risk with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours per year that the 50<sup>th</sup> percentile demand forecast is expected to exceed the N-1 capability rating after 2024. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50<sup>th</sup> percentile demand forecast.



### Comments on Energy at Risk

For an outage of one transformer at BATS 66 kV, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 7 hours in 2028. The energy at risk at the 50<sup>th</sup> percentile temperature under N-1 conditions is estimated to be 41.1 MWh, which is valued at approximately \$1.6 million (based on a value of customer reliability of \$38,459/MWh). In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at BATS in 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$1.6 million.

It is emphasised however, that the probability of a major outage of one of the two 150 MVA transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (41.1 MWh for 2028) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 0.18 MWh. This expected unserved energy is estimated to have a value to consumers of \$6,850 (based on a value of customer reliability of \$38,459/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures

occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2028 is estimated to be 474.7 MWh. The estimated value to consumers of this energy at risk in 2028 is approximately \$18.3 million. The corresponding value of the expected unserved energy (of 2.06 MWh) is \$79,100.

These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	41.1	\$1.6 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	0.18	\$6,850
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	474.7	\$18.3 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	2.06	\$79,100

### Feasible options for alleviation of constraints

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

- Installation of a third 220/66 kV transformer (150 MVA) at BATS at an indicative capital cost of \$14 million.
- Demand reduction: There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction would depend on the customer uptake and would be taken into consideration when determining the optimum timing for any future capacity augmentation.
- An alternative option to the network solution could be the establishment of an embedded generator, suitably located in the area that is presently supplied by the BATS 66 kV network.
- There are presently several large embedded generation 66 kV wind farm proposals in the area which may drive the need for an additional 220/66 kV transformer at BATS to accommodate the reverse power flow expected at BATS.

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

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

1. Install a third 220/66 kV transformer (150 MVA) at BATS at an indicative capital cost of \$14 million. This equates to a total annual cost of approximately \$0.82 million per annum. On the basis of the medium economic growth scenario and both 50<sup>th</sup> and 10<sup>th</sup> percentile weather probability, the transformer would not be expected to be required in the forecast period.

2. As a temporary measure, maintain contingency plans to transfer load quickly to the Horsham Terminal Station (HOTS) and Brooklyn Terminal Station (BLTS 66) by the use of the 66 kV tie lines that run from BATS to HOTS and BATS to BLTS 66 in the event of an unplanned outage of one transformer at BATS under critical loading conditions. This load transfer is in the order of 15 MVA. Under these temporary measures, affected customers would be supplied from the 66 kV tie line infrastructure on a radial network, thereby reducing the level of supply reliability they receive.
3. Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for rural areas (refer Section 5.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

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

## BATS Terminal Station

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

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

	<b>MW</b>	<b>MVA</b>	
Normal cyclic rating with all plant in service	358	450	via 2 transformers (summer)
Summer N-1 Station Rating:	183	225	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating:	206	250	

Station: BATS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	160.4	168.3	173.5	176.7	179.7	181.6	185.3	189.6	193.8	197.3
50th percentile Winter Maximum Demand (MVA)	177.4	181.9	184.8	188.3	193.7	196.6	199.5	203.2	206.9	211.1
10th percentile Summer Maximum Demand (MVA)	175.6	185.5	190.6	194.1	199.1	199.2	202.5	208.3	210.8	217.7
10th percentile Winter Maximum Demand (MVA)	193.0	197.6	201.2	203.7	208.7	211.9	216.6	219.1	222.2	227.1
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.8	7.3	20.2	41.1
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.5	2.3	3.8	7.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	1.0	9.9	21.5	50.6	55.3	99.1	188.3	254.5	474.7
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.5	2.5	3.8	7.5	8.8	14.3	21.3	28.3	46.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.09	0.18
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.04	0.09	0.22	0.24	0.43	0.82	1.10	2.06
Expected Unserved Energy value at 50th percentile demand	\$0.00M	\$0.01M								
Expected Unserved Energy value at 10th percentile demand	\$0.00M	\$0.00M	\$0.00M	\$0.00M	\$0.01M	\$0.01M	\$0.02M	\$0.03M	\$0.04M	\$0.08M
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	\$0.01M	\$0.01M	\$0.02M	\$0.03M

**Notes:**

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

## BENDIGO TERMINAL STATION (BETS) 22 kV

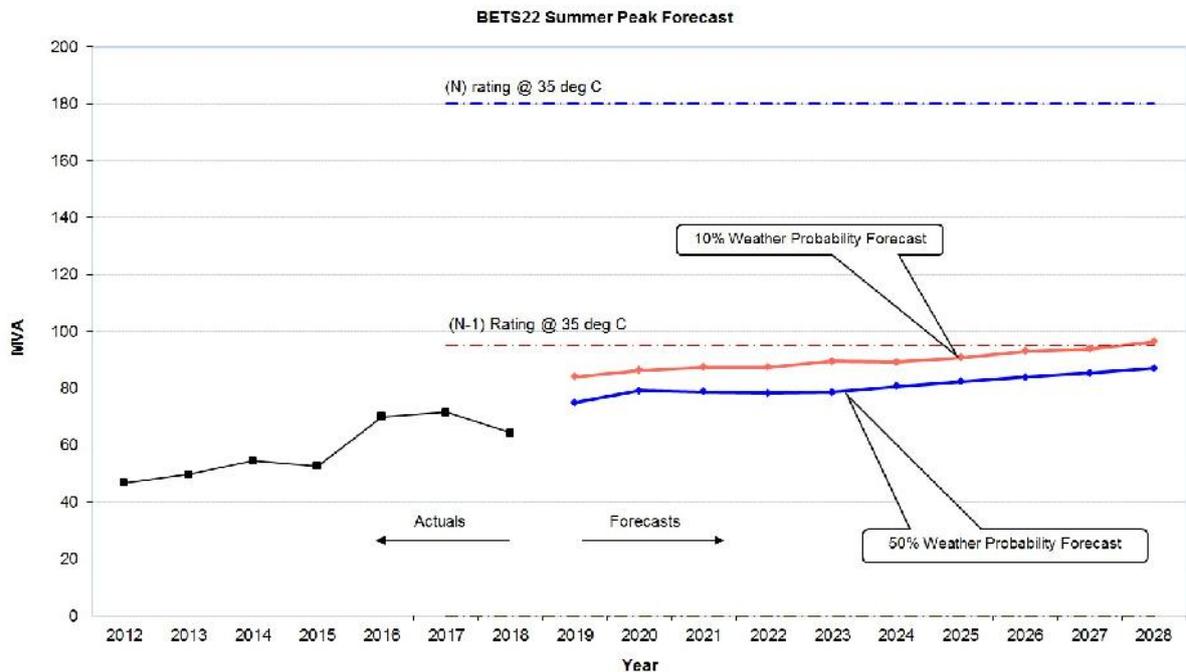
Bendigo Terminal Station (BETS) 22 kV consists of two 75 MVA 235/22.5 kV transformers supplying the 22 kV network ex-BETS. These two transformers have been in service since mid 2013 and they have enabled the separation of the 66 kV and 22 kV points of supply, and the transfer of load from the existing 230/66/22kV transformers. This configuration is the main source of supply for 26,867 customers in Bendigo and the surrounding area. The station supply area includes Marong, Newbridge and Lockwood.

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

BETS 22 kV demand is summer peaking. Growth in summer peak demand on the 22 kV network at BETS has averaged around 2.9 MVA (6.2%) per annum over the last 5 years. The peak load for the 22 kV network now on the station reached 63.9 MW in summer 2018. There were load transfers from Eaglehawk Zone Substation to BETS 22 which have contributed to the higher peak demand since 2016 compared to 2015. It is estimated that:

- For 9 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at the time of peak demand is 0.99.

The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> 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 above graph shows that there is sufficient capacity at the station to supply all expected demand at the 50<sup>th</sup> and 10<sup>th</sup> percentile temperature, over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

## BENDIGO TERMINAL STATION (BETS) 66 kV

### Background

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

Also in 2013, two 70/57/51 MVA 230/66/22 kV transformers were retired and one new 150 MVA 220/66 kV transformer was commissioned in service supplying the 66 kV buses in parallel with one existing 125/125/40 MVA 230/66/22 kV transformer. These transformers provide the main source of 66 kV supply for 61,656 customers in Bendigo and the surrounding area. The station supply area includes Bendigo CBD, Eaglehawk, Charlton, St. Arnaud, Maryborough and Castlemaine.

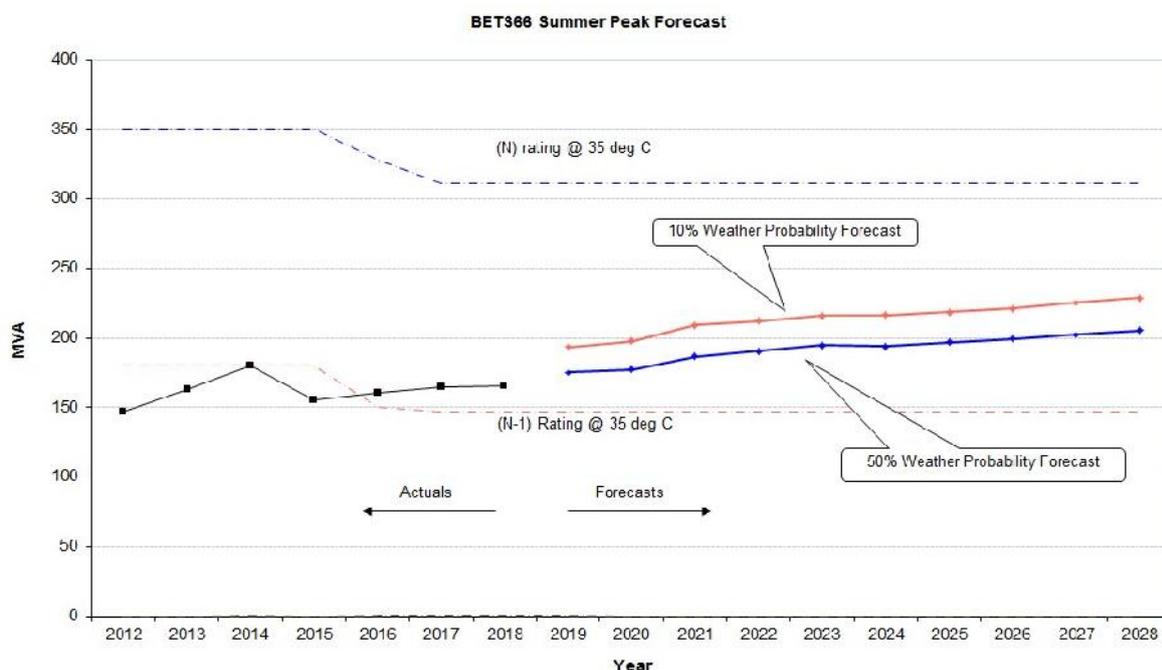
AusNet Transmission Group down-rated the transformers in 2015. As a result the BETS 66 station has new ratings with the N rating reduced from 328 MVA to 310.9 MVA and the N-1 rating reduced from 150 MVA to 146.7 MVA in summer. These new ratings are depicted in the graph below.

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

Growth in summer peak demand at BETS 66 kV has averaged around 0.48 MVA (0.6%) per annum over the last 5 years. The peak load on the station reached 165.8 MW in summer of 2018. It is estimated that:

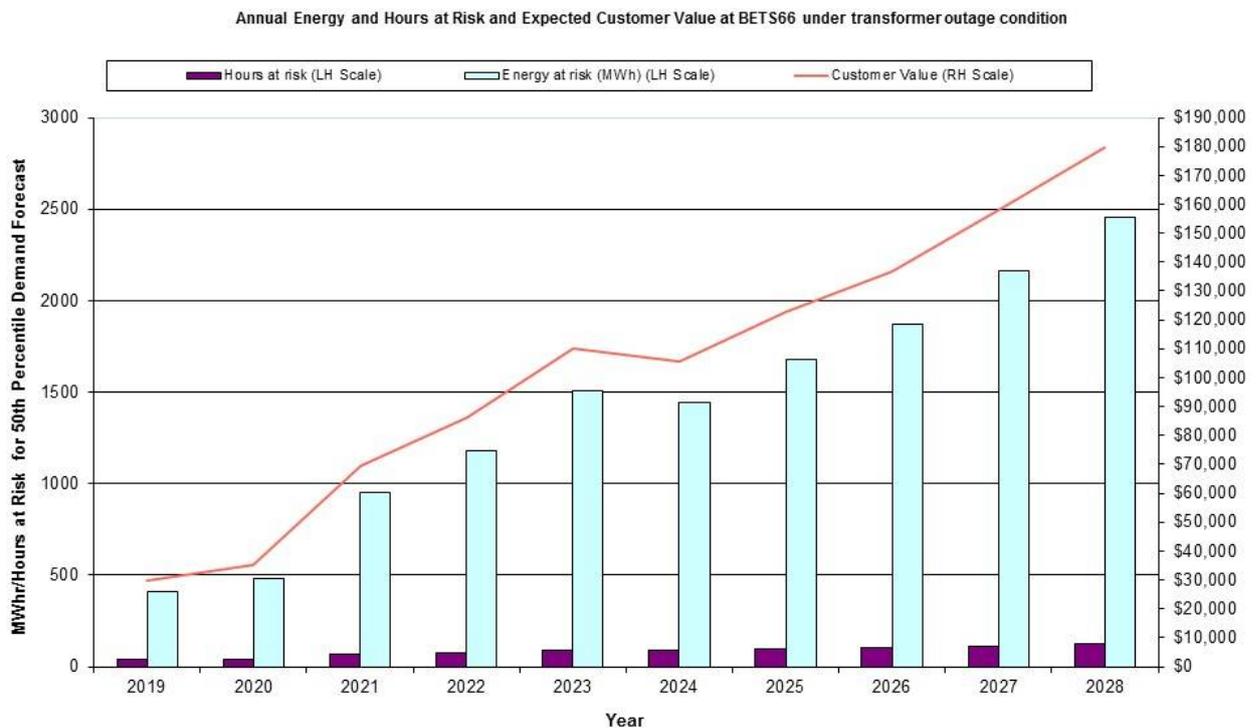
- For 16.5 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at time of peak demand is 0.99.

BETS 66 kV demand is summer peaking. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperatures.



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

The bar chart below depicts the energy at risk with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours per year that the 50<sup>th</sup> 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 50<sup>th</sup> percentile demand forecast.



### Comments on Energy at Risk

For a major outage of one transformer at BETS 66 kV during the summer period, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 122.5 hours in 2028. The energy at risk at the 50<sup>th</sup> percentile temperature under N-1 conditions is estimated to be 2,455 MWh in 2028. The estimated value to consumers of the 2,455 MWh of energy at risk is approximately \$82.9 million (based on a value of customer reliability of \$33,759/MWh).<sup>1</sup> In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at BETS 66kV in 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately \$82.9 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (2,455 MWh for 2028) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 5.3 MWh. This expected unserved energy is estimated to

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

have a value to consumers of around \$0.18 million, (based on a value of customer reliability of \$33,759/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2028 is estimated to be 5,592 MWh. The estimated value to consumers of this energy at risk in 2028 is approximately \$188.8 million. The corresponding value of the expected unserved energy (of 12.1 MWh) is approximately \$0.41 million.

These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	2,455	\$82.9 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	5.3	\$0.18 million
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	5,592	\$188.8 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	12.1	\$0.41 million

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

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

### **Feasible options for alleviation of constraints**

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

1. Implement a contingency plan to transfer 22 MVA of load away to BETS 22 kV, WETS, KTS East 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 \$18 million (equating to a total annual cost of approximately \$1.04 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

<sup>2</sup> Overload Shedding Scheme of Connection Asset.

<sup>3</sup> Transmission Operation Centre.

would be taken into consideration when determining the optimum timing for the capacity augmentation.

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

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

As already noted, a contingency plan to transfer 22 MVA of load to BETS 22 kV, WETS, KTS East 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 rating would be the preferred option.

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

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

## Bendigo Terminal Station

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

**Distribution Businesses supplied by this station:** Powercor (100%)  
**Normal cyclic rating with all plant in service** 310.9 MVA via 2 transformers (Summer peaking)  
**Summer N-1 Station Rating:** 146.7 MVA [See Note 1 below for interpretation of N-1]  
**Winter N-1 Station Rating:** 173.7 MVA

Station: BETS66	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	175.1	177.1	186.6	190.3	194.8	193.9	196.9	199.2	202.3	205.3
50th percentile Winter Maximum Demand (MVA)	127.5	132.1	135.1	137.1	138.7	140.1	142.1	143.9	145.7	148.0
10th percentile Summer Maximum Demand (MVA)	193.5	197.7	209.0	212.2	216.0	216.5	218.5	221.2	225.4	228.9
10th percentile Winter Maximum Demand (MVA)	141.8	147.7	149.2	150.3	152.6	154.1	156.7	158.0	159.9	162.1
N-1 energy at risk at 50% percentile demand (MWh)	407	478.8	948.6	1180.8	1506.8	1443.7	1675.6	1871.5	2162.1	2455.3
N-1 hours at risk at 50th percentile demand (hours)	37.5	41.8	66.3	77.0	89.8	87.3	96.5	103.0	113.0	122.5
N-1 energy at risk at 10% percentile demand (MWh)	1409	1742	2853	3222	3699	3771	4038	4412	5032	5592
N-1 hours at risk at 10th percentile demand (hours)	85.8	98.3	136.5	148.0	160.8	162.3	170.0	181.0	198.8	213.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.9	1.0	2.1	2.6	3.3	3.1	3.6	4.1	4.7	5.3
Expected Unserved Energy at 10th percentile demand (MWh)	3.1	3.8	6.2	7.0	8.0	8.2	8.7	9.6	10.9	12.1
Expected Unserved Energy value at 50th percentile demand	\$0.03M	\$0.04M	\$0.07M	\$0.09M	\$0.11M	\$0.11M	\$0.12M	\$0.14M	\$0.16M	\$0.18M
Expected Unserved Energy value at 10th percentile demand	\$0.10M	\$0.13M	\$0.21M	\$0.24M	\$0.27M	\$0.28M	\$0.30M	\$0.32M	\$0.37M	\$0.41M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$0.05M	\$0.06M	\$0.11M	\$0.13M	\$0.16M	\$0.16M	\$0.17M	\$0.19M	\$0.22M	\$0.25M

#### Notes:

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

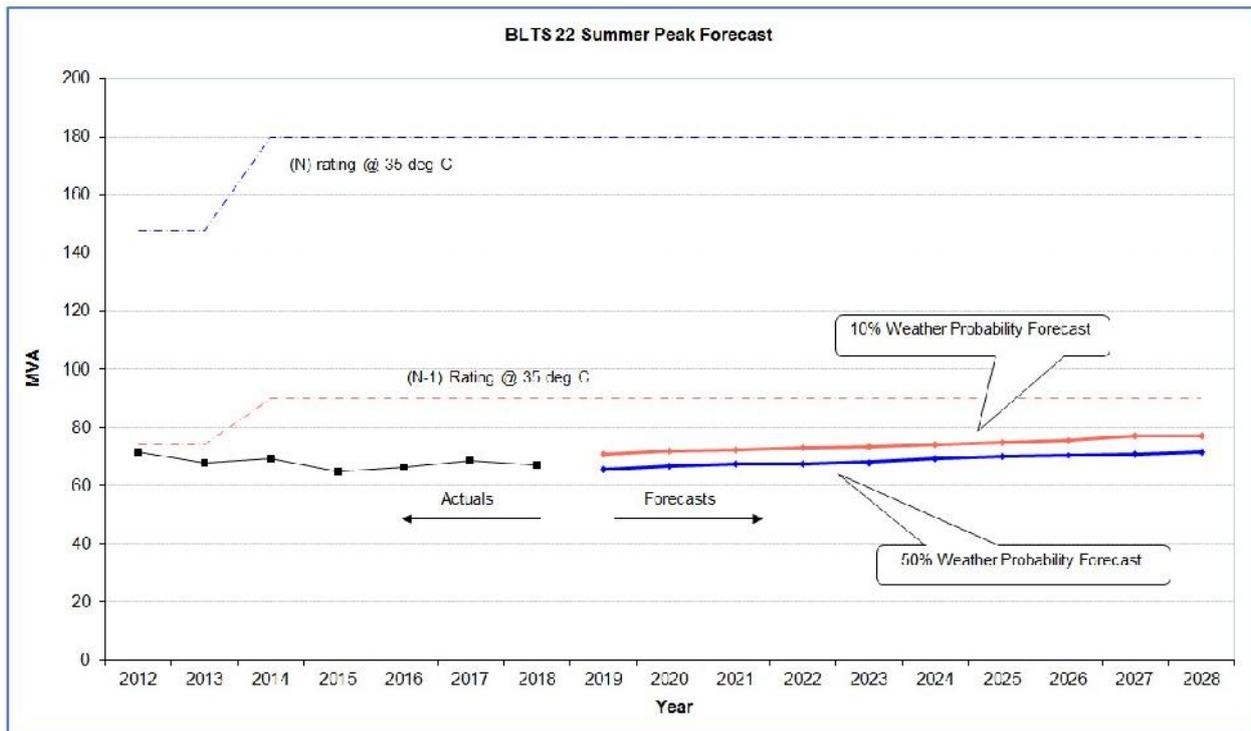
## BROOKLYN TERMINAL STATION (BLTS) 22 kV

The Brooklyn Terminal Station (BLTS) 22 kV supply area includes Altona, Brooklyn and Laverton North. The station supplies both Jemena Electricity Network (3%) and Powercor (97%) customers.

Brooklyn Terminal Station (BLTS) 22 kV was rebuilt by AusNet Transmission Group in 2012-13, with two new 75 MVA 220/22 kV transformers. This configuration is the main source of supply for 7,351 customers in Brooklyn and the surrounding area. The load characteristic for BLTS 22 kV substation is of a mixed nature, consisting of residential and industrial customers. In recent years, the industrial load has declined in the area; however this has been offset by some growth from residential developments. Growth in summer peak demand on the 22 kV network at BLTS is expected to increase at an average of around 1% per annum over the next ten years. The peak load demand on the entire BLTS 22 kV network reached 59.3 MW (67 MVA) in summer 2018. It is estimated that:

- For 60 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station transformer power factor at the time of peak demand is 0.88.

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



The “N” rating on the chart indicates the maximum load that can be supplied from BLTS 22 kV Terminal Station with all transformers in service. The “N-1” rating on the chart is the load that can be supplied with one 75 MVA transformer out of service.

The graph shows there is sufficient capacity at the station to supply all expected demand at the 10<sup>th</sup> and 50<sup>th</sup> percentile temperature, over the forecast period, with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

## BRUNSWICK TERMINAL STATION 22 kV (BTS 22 kV)

BTS 22 kV is a terminal station located in an inner northern suburb of Melbourne and shared by Jemena Electricity Networks (55%) and CitiPower (45%). It operates at 220/22 kV and supplies a total of approximately 44,500 customers in the Brunswick, Fitzroy, Northcote, Fairfield, Essendon, Ascot Vale and Moonee Ponds areas.

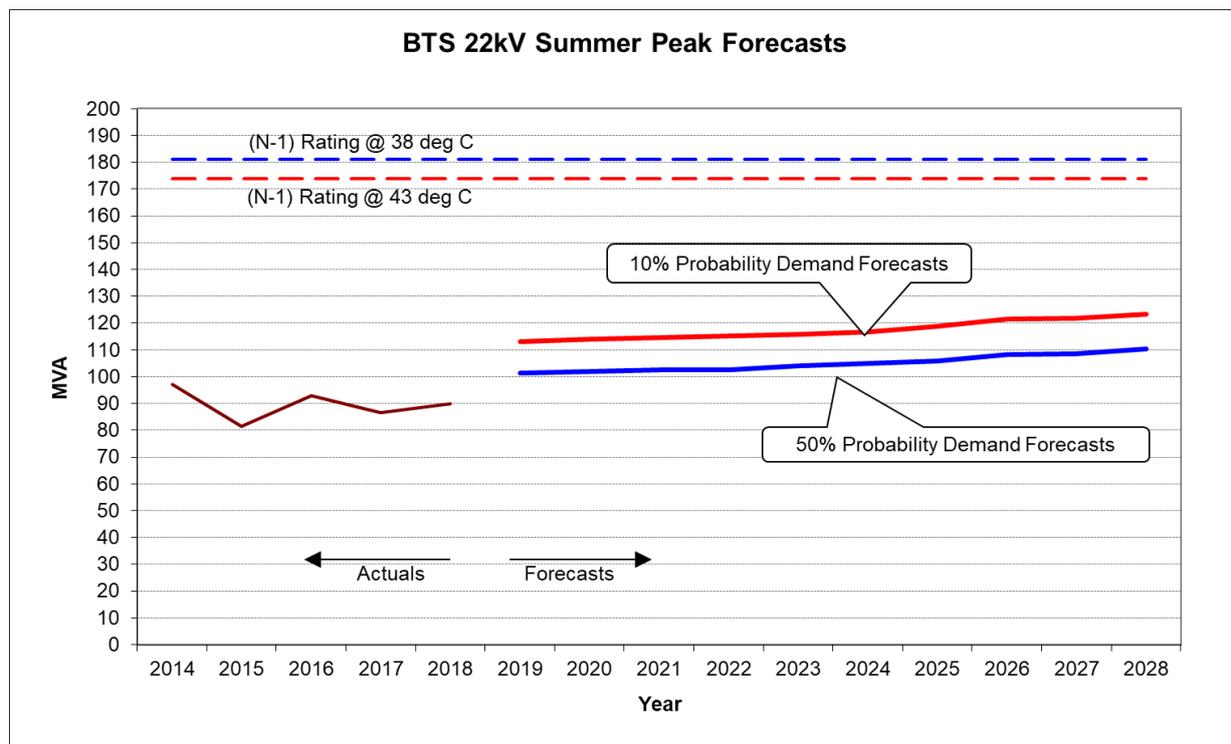
### Magnitude, probability and impact of loss of load

BTS 22 kV is a summer critical station with three 75 MVA transformers operating in parallel. The peak load on the station transformers reached 86.5 MW (or 89.9 MVA) in summer (January) 2018.

It is estimated that:

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

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



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

<sup>1</sup> Note that station transformer output capability rating and transformers' loading is used.

## BRUNSWICK TERMINAL STATION 66 kV (BTS 66 kV)

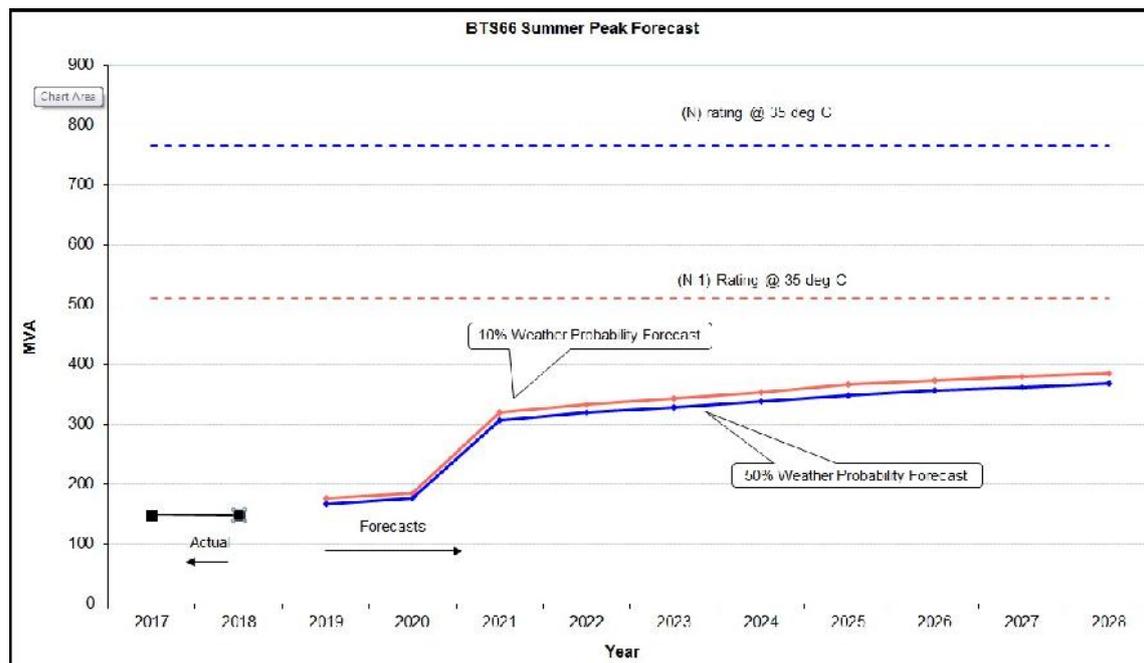
Brunswick Terminal Station (BTS) 66 kV consists of 3 x 225 MVA 220/66 kV transformers. It reinforces the security of supply to the northern and inner suburbs and the Central Business District areas and will provide future supply to the nearby suburbs of Brunswick, Brunswick West, Northcote, Carlton, Fitzroy and Collingwood. It currently provides supply to approximately 27,323 customers.

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

The BTS load currently includes transfers from WMTS 66 kV. Further load transfers from RTS 66 and WMTS 22 will occur in 2019 and 2020 as shown below. The BTS demand will be summer peaking. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35 degrees C ambient temperature.

The 50<sup>th</sup> percentile peak load on the station reached 144.9 MW in summer 2017/18 with a station load power factor of 0.97.

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



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

## CRANBOURNE TERMINAL STATION (CBTS)

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

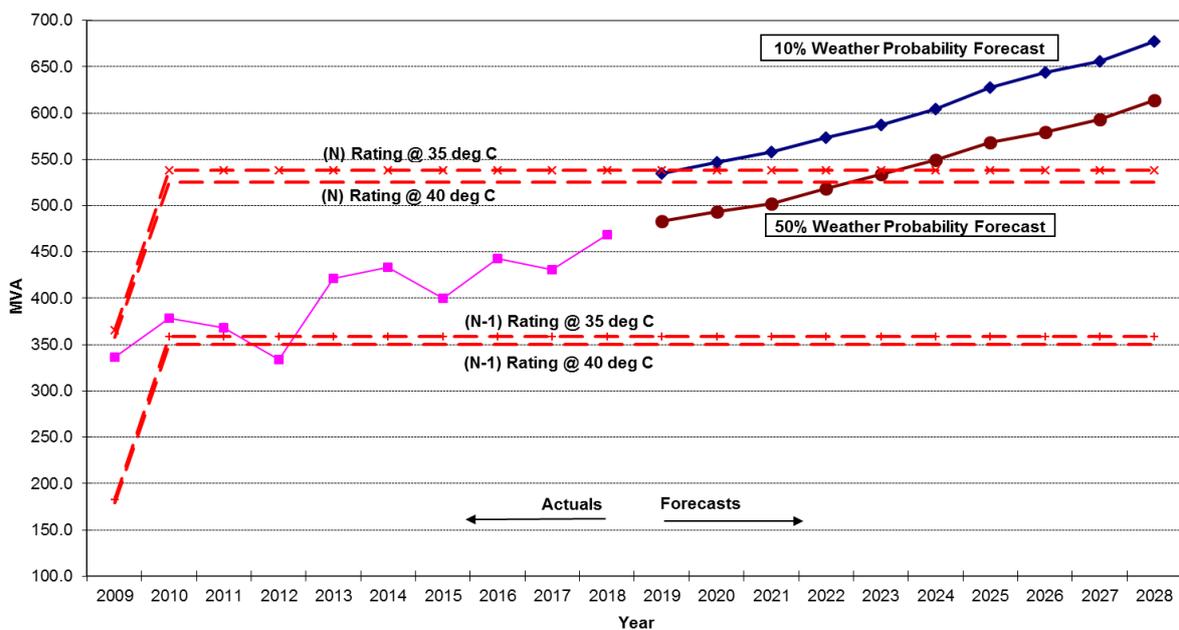
The geographic area supplied by CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west. The electricity distribution networks for this area are the responsibility of both AusNet Electricity Services (62%) and United Energy (38%).

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

The summer peak demand at CBTS 66 kV has increased by 159 MVA between 2007/08 and 2017/18, which is equivalent to an average annual growth rate of 4.7%. The peak demand on the station reached 453.4 MW (469.0 MVA) in summer 2017/18, which is an all-time peak demand record for the station. 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 50<sup>th</sup> percentile peak demand for 2 hours per annum.

CBTS 66 kV is a summer peaking station and is expected to be loaded above its “N-1” rating in summer, and above its “N” rating under 10<sup>th</sup> percentile summer maximum demand conditions. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station’s expected operational “N” rating (all transformers in service) and the “N-1” rating at 35°C as well as 40°C ambient temperatures.

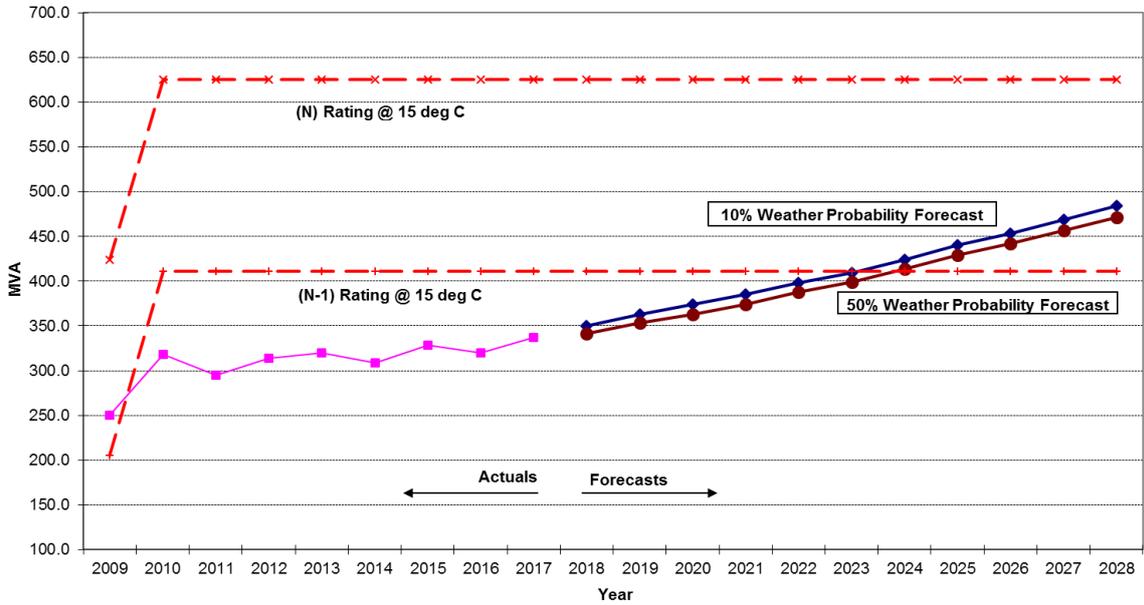
CBTS 66 kV Summer Peak Demand Forecasts



The “N” rating on the chart indicates the maximum load that can be delivered from CBTS 66 kV with all transformers in service. Exceeding this level will initiate AusNet Transmission Group’s automatic load shedding scheme (OSSCA).

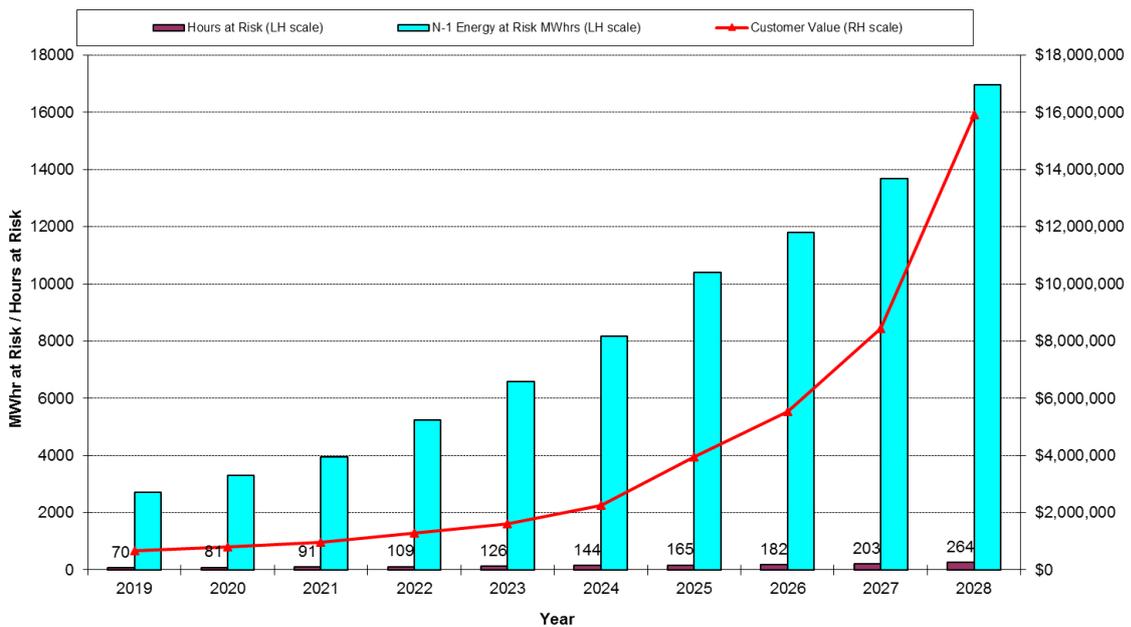
The winter ratings of transformers are higher than the summer ratings due to lower ambient temperatures. Thus, energy at risk during the winter period is generally lower than the summer period for summer peaking stations. The graph below demonstrates the 10<sup>th</sup> and the 50<sup>th</sup> percentile winter maximum demand forecast together with the station’s operational “N” rating and “N-1” rating for winter.

CBTS 66 kV Winter Peak Demand Forecasts



The bar chart below depicts the energy at risk with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours per year that the 50<sup>th</sup> 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 50<sup>th</sup> percentile demand forecast.

Annual Energy and Hours at Risk at CBTS 66 kV (Single Contingency Only)



## Comments on Energy at Risk

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

For an outage of one 220/66 kV transformer at CBTS, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 70 hours in 2018/19. The energy at risk under “N-1” conditions is estimated to be 2,708 MWh in 2018/19. The estimated value to consumers of the 2,708 MWh of energy at risk is approximately \$102 million (based on a value of customer reliability of \$37,748/MWh)<sup>1</sup>. In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one 220/66 kV transformer at CBTS for the entire duration of the 2018/19 summer would lead to involuntary supply interruptions that are valued by consumers at \$102 million.

It is emphasised however, that the probability of a major transformer outage is very low, with a network average of 1.0% per transformer per annum applied for this TCPR assessment, contributing to an expected unavailability per transformer per annum of 0.217%. When the energy at risk (2,708 MWh) is weighted by this low unavailability, the expected unserved energy is estimated to be around 17.6 MWh. This expected unserved energy is estimated to have a value to consumers of around \$0.67 million (based on a value of customer reliability of \$37,748/MWh).

The above estimates of energy at risk and expected unserved energy are based on an assumption of moderate temperatures occurring in each year. Under higher temperature conditions (that is, at the 10<sup>th</sup> percentile level), there is a higher amount of energy at risk under “N-1” and “N” conditions at CBTS. The “N-1” and “N” energy at risk in summer 2018/19 is estimated to be 7,669 MWh and 19.7 MWh respectively. The total estimated value to consumers of this energy at risk in 2018/19 is approximately \$290 million. The corresponding value of the expected unserved energy (of 70 MWh) is \$2.63 million.

These key statistics for the year 2018/19 under “N” and “N-1” outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
“N” Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0	\$0
“N-1” Energy at risk, at 50 <sup>th</sup> percentile demand forecast	2,708	\$102 million
“N” and “N-1” Expected unserved energy at 50 <sup>th</sup> percentile demand	17.6	\$0.67 million
“N” Energy at risk, at 10 <sup>th</sup> percentile demand forecast	19.7	\$0.74 million
“N-1” Energy at risk, at 10 <sup>th</sup> percentile demand forecast	7,669	\$290 million
“N” and “N-1” Expected unserved energy at 10 <sup>th</sup> percentile demand	70	\$2.63 million

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

## Possible impacts of a transformer outage on customers

If one of the 220/66 kV transformers at CBTS is taken off line during peak loading times and the N-1 station rating is exceeded, the Overload Shedding Scheme for Connection Assets (OSSCA)<sup>2</sup> which is operated by AusNet Transmission Group's TOC<sup>3</sup> will act swiftly to reduce the loads in blocks to within ratings of available plant. In the event of OSSCA operating, it would automatically shed up to 200 MVA of load, affecting up to 75,000 customers in 2018/19. 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.

## 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 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 10<sup>th</sup> 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 and have a combined capability to transfer up to 150 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 4<sup>th</sup> 220/66 kV transformer at Cranbourne Terminal Station: The site has provision for a 4<sup>th</sup> 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 15 MVA, and could defer a network augmentation by one to two years. AEMO has also been considering installing capacitors at CBTS to

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<sup>2</sup> 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.

<sup>3</sup> Transmission Operations Centre

support the transmission network, and any opportunity to install 66 kV capacitors at CBTS to provide benefits in both areas will be identified through joint planning with AEMO.

5. Demand Management: United Energy and AusNet Electricity Services have developed a number of innovative network tariffs that encourage voluntary demand reduction during times of network constraints. The amount of demand reduction depends on the tariff uptake and the subsequent change in the load pattern, and will be taken into consideration when determining the optimum timing for the capacity augmentation.
6. Embedded Generation: Embedded generation, with a capacity in the order of 20 MW, connected to the CBTS 66 kV bus, could defer the need for augmentation by approximately two years.

### **Preferred network option for alleviation of constraints**

AusNet Electricity Services and United Energy have commenced discussions to develop a Regulatory Investment Test for Transmission (RIT-T) to address the supply risks at CBTS. Due to consistent growth in maximum demand since 2012, and the significant increase in forecast maximum demand this year, it is estimated that a fourth 150 MVA 220/66 kV transformer could be economically justified as soon as 2018/19. It should be noted however, that taking into account load transfers and emergency ties, the optimal economic timing would likely be deferred by approximately 2 years.

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

- maintain emergency plans to transfer load to adjacent terminal stations via 22 kV feeders and 66 kV tie lines;
- fine-tune the OSSCA scheme settings to minimise the impact on customers of any automatic load shedding that may take place; and
- subject to the availability of a spare 220/66 kV transformer for metropolitan areas (refer Section 5.5), a spare transformer can be used to temporarily replace a failed transformer.

The capital cost of installing a fourth 150 MVA 220/66 kV transformer at CBTS is estimated to be \$20 million. The cost of establishing, operating and maintaining a new transformer would be recovered from network users through network charges, over the life of the asset. The estimated total annual cost of this network augmentation is approximately \$1.2 million. This cost provides a broad upper bound for the maximum annual network support payment which may be available to embedded generators or customers to reduce forecast demand, and to defer or avoid the transmission connection component of this augmentation. Any non-network solution that defers this augmentation for say 1-2 years, will not have as much potential value (and contribution available from distributors) as a solution that eliminates or defers the augmentation for, say, 10 years.

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

**CRANBOURNE TERMINAL STATION****Detailed data: Magnitude and probability of loss of load**

Distribution Businesses supplied by this station:

United Energy (38%) and AusNet Electricity Services (62%)

Normal cyclic rating with all plant in service

538 MVA via 3 transformers (Summer peaking)

Summer N-1 Station Rating

359 MVA [See Note 1 below for interpretation of N-1]

Winter N-1 Station Rating

411 MVA

Station: CBTS 66 kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	483.5	493.2	502.3	518.7	533.6	549.0	568.3	579.4	592.9	613.5
50th percentile Winter Maximum Demand (MVA)	353.2	363.2	374.4	388.1	398.9	413.4	429.2	442.0	456.3	471.5
10th percentile Summer Maximum Demand (MVA)	534.5	546.6	557.6	573.6	587.3	604.6	627.9	644.1	656.2	676.9
10th percentile Winter Maximum Demand (MVA)	363.1	373.6	385.3	397.9	409.8	424.0	440.2	453.3	468.3	484.0
N - 1 energy at risk at 50th percentile demand (MWh)	2,708	3,303	3,936	5,231	6,593	8,173	10,395	11,791	13,687	16,961
N - 1 hours at risk at 50th percentile demand (hours)	70	81	91	109	126	143	163	178	197	250
N - 1 energy at risk at 10th percentile demand (MWh)	7,669	8,760	9,836	11,538	13,126	15,387	18,987	22,033	25,021	30,535
N - 1 hours at risk at 10th percentile demand (hours)	110	122	134	150	166	196	249	296	360	444
N energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	6	37	70	135	311
N energy at risk at 10th percentile demand (MWh)	20	112	239	503	802	1,242	1,920	2,451	2,876	3,692
N and N-1 Expected Unserved Energy at 50th percentile demand (MWh)	18	22	26	34	43	60	105	147	224	422
N and N-1 Expected Unserved Energy at 10th percentile demand (MWh)	70	169	303	578	887	1,342	2,044	2,595	3,039	3,891
N and N-1 Expected Unserved Energy value at 50th percentile demand	\$0.66M	\$0.81M	\$0.97M	\$1.29M	\$1.62M	\$2.25M	\$3.95M	\$5.55M	\$8.45M	\$15.92M
N and N-1 Expected Unserved Energy value at 10th percentile demand	\$2.63M	\$6.38M	\$11.43M	\$21.83M	\$33.48M	\$50.67M	\$77.16M	\$97.95M	\$114.73M	\$146.89M
N and N-1 Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$1.25M	\$2.48M	\$4.11M	\$7.45M	\$11.18M	\$16.78M	\$25.91M	\$33.27M	\$40.33M	\$55.21M

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 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50<sup>th</sup> and 10<sup>th</sup> percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))

## 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 52,855 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 constraint at KTS from the summer 2017/18 onwards. The 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 to augment supply to the fast-growing western suburbs of Melbourne.

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

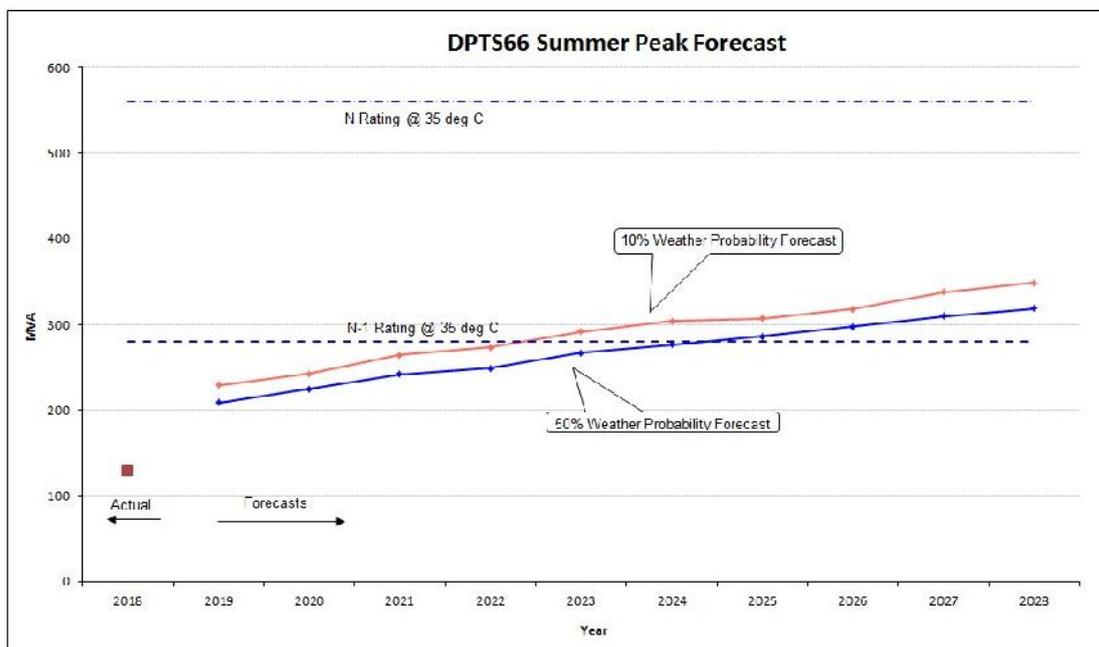
### Magnitude, probability and impact of loss of load

The first recorded peak load on the station reached 127.2 MW in summer 2018. Peak demand at the 10<sup>th</sup> percentile temperature is forecast to increase to 324.4 MW by 2028, due to the high load growth in the western suburbs of Melbourne and additional transfers from LVN, SU, LV and WBE zone substations.

It is estimated that:

- For 30 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile forecast.
- The station load power factor at time of peak demand is 0.98

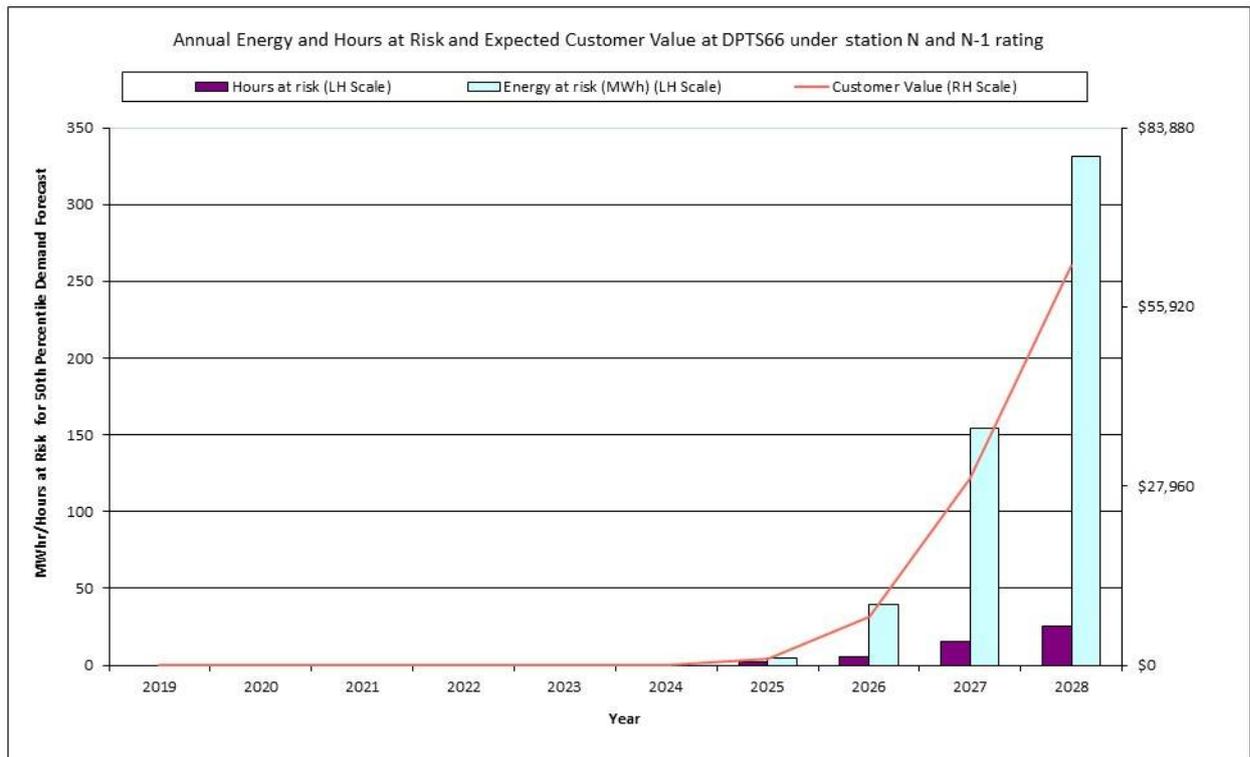
The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile maximum demand forecasts together with the stations estimated operational “N” rating (all transformers in service) and the “N-1” rating at 35°C ambient temperature.



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

The graph shows there is insufficient capacity at the station to supply all expected demand at the 50<sup>th</sup> percentile temperature from 2024 and from 2022 at the 10<sup>th</sup> percentile temperature if a forced outage of a transformer occurs.

The bar chart below depicts the energy at risk with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours per year that the 50<sup>th</sup> 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 50<sup>th</sup> percentile demand forecast.



### Comments on Energy at Risk

For an outage of one transformer at DPTS 66 kV, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 25.5 hours in 2028. The energy at risk at the 50<sup>th</sup> percentile temperature under N-1 conditions is estimated to be 331.5 MWh in 2028. The estimated value to consumers of the 331.5 MWh of energy at risk is approximately \$14.4 million (based on a value of customer reliability of \$43,462/MWh)<sup>1</sup>. In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at DPTS in 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$14.4 million.

It is emphasised however, that the probability of a major outage of one of the two 225 MVA transformers occurring over the year is very low at about 1.0% per transformer per annum,

<sup>1</sup> 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.

whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (331.5 MWh for 2028) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 1.44 MWh. This expected unserved energy is estimated to have a value to consumers of \$62,400 (based on a value of customer reliability of \$43,462/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2028 is estimated to be 1,489 MWh. The estimated value to consumers of this energy at risk in 2028 is approximately \$64.7 million. The corresponding value of the expected unserved energy (of 6.46 MWh) is \$280,000.

These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast under N-1 outage condition	331.5	\$14.4 million
Expected unserved energy at 50th percentile demand under N-1 outage condition	1.44	\$62,400
Energy at risk, at 10th percentile demand forecast under N-1 outage condition	1,489	\$64.7 million
Expected unserved energy at 10th percentile demand under N-1 outage condition	6.46	\$280,000

## Possible Impact on Customers

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

Applying the 50<sup>th</sup> percentile and 10<sup>th</sup> percentile 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 peak loading times and the N-1 station 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 15 MVA in summer 2025.

## Preferred 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 constraint:

1. Install additional transformation capacity at DPTS, at an estimated indicative capital cost of approximately \$18 million (equating to a total annual cost of approximately \$1.04 million per annum). This would result in the station being configured so that three transformers are supplying the DPTS load.

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.

### **Preferred network option for alleviation of constraints**

In the absence of a commitment by interested parties to offer network support services that would reduce the load at DPTS, the preferred network option to address emerging constraints at DPTS would be to install an additional transformer, for which space exists at the site. Given the present forecasts of expected unserved energy, the installation of an additional transformer at DPTS is unlikely to be economic over the 10 year planning horizon.

## Deer Park Terminal Station

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

Distribution Businesses supplied by this station:

Powercor (100%)  
MW MVA

Normal cyclic rating with all plant in service

Summer N-1 Station Rating:

Winter N-1 Station Rating:

	MW	MVA
Normal cyclic rating with all plant in service		560
Summer N-1 Station Rating:	269	280
Winter N-1 Station Rating:	289	300

via 2 transformers (Summer peaking)

[See Note 1 below for interpretation of N-1]

Station: DPTS66	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	208.8	225.1	242.0	249.1	266.8	276.9	285.9	297.7	309.5	319.1
50th percentile Winter Maximum Demand (MVA)	119.6	131.8	137.4	146.7	151.9	157.8	163.0	168.0	174.1	180.7
10th percentile Summer Maximum Demand (MVA)	229.1	242.9	264.6	273.7	291.8	304.4	307.1	318.3	337.7	348.7
10th percentile Winter Maximum Demand (MVA)	130.3	141.8	147.8	158.0	163.6	168.6	173.4	178.2	185.5	192.1
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	4.9	39.9	154.4	331.5
N-1 hours at risk at 50th percentile demand (hours)	0.0	0.0	0.0	0.0	0.0	0.0	1.8	5.5	15.8	25.5
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	0.0	0.0	17.5	89.7	120.7	314.9	932.4	1489.8
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	0.0	0.0	3.0	10.5	14.0	24.8	48.0	65.5
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.17	0.67	1.44
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.08	0.39	0.52	1.36	4.04	6.46
Expected Unserved Energy value at 50th percentile demand	\$0.00M	\$0.01M	\$0.03M	\$0.06M						
Expected Unserved Energy value at 10th percentile demand	\$0.00M	\$0.00M	\$0.00M	\$0.00M	\$0.00M	\$0.02M	\$0.02M	\$0.06M	\$0.18M	\$0.28M
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	\$0.01M	\$0.01M	\$0.02M	\$0.07M	\$0.13M

#### NOTES:Notes:

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

## EAST ROWVILLE TERMINAL STATION (ERTS)

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

ERTS 66 kV is a summer critical station. The station reached its highest recorded peak demand of 504.9 MW (523.4 MVA) in summer 2009 under extreme weather conditions. The recorded demand in summer 2018 was 435.4 MW (448.5 MVA). Five embedded generation units over 1 MW are connected at ERTS 66 kV.<sup>1</sup>

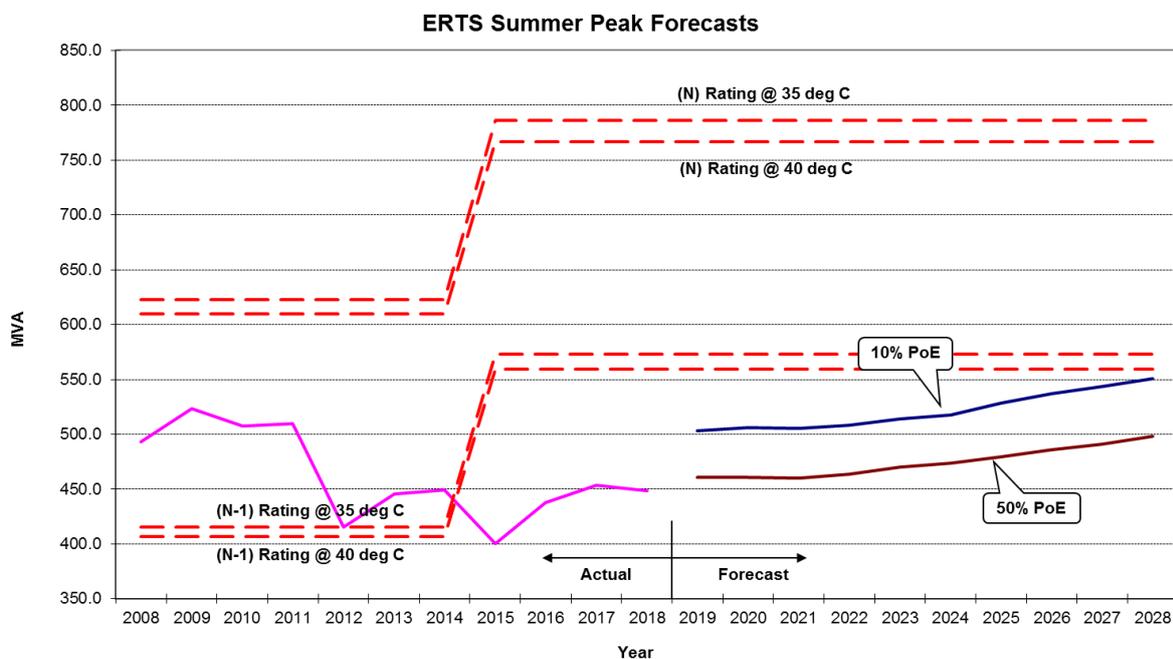
The risk of supply interruption at ERTS 66 kV for a single contingency event was assessed as being unacceptable in 2007. As a result, a Regulatory Test was undertaken by both AusNet Electricity Services and United Energy which identified the installation of a fourth 150 MVA 220/66 kV transformer as the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

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

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

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

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



<sup>1</sup> The maximum demand forecasts adopted in this risk analysis excludes the impact of the five embedded generators.

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

The graph indicates that the overall demand at ERTS remains below its N rating within the 10 year planning period. The 10<sup>th</sup> and 50<sup>th</sup> percentile overall summer demand is expected to remain within the N-1 rating for the entire planning period.

The station load is forecast to have a power factor of 0.983 at times of peak demand. The demand at ERTS is expected to exceed 95% of the peak demand for approximately 8 hours per annum. There is approximately 77 MVA of load transfer available at ERTS for summer 2018/19.

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

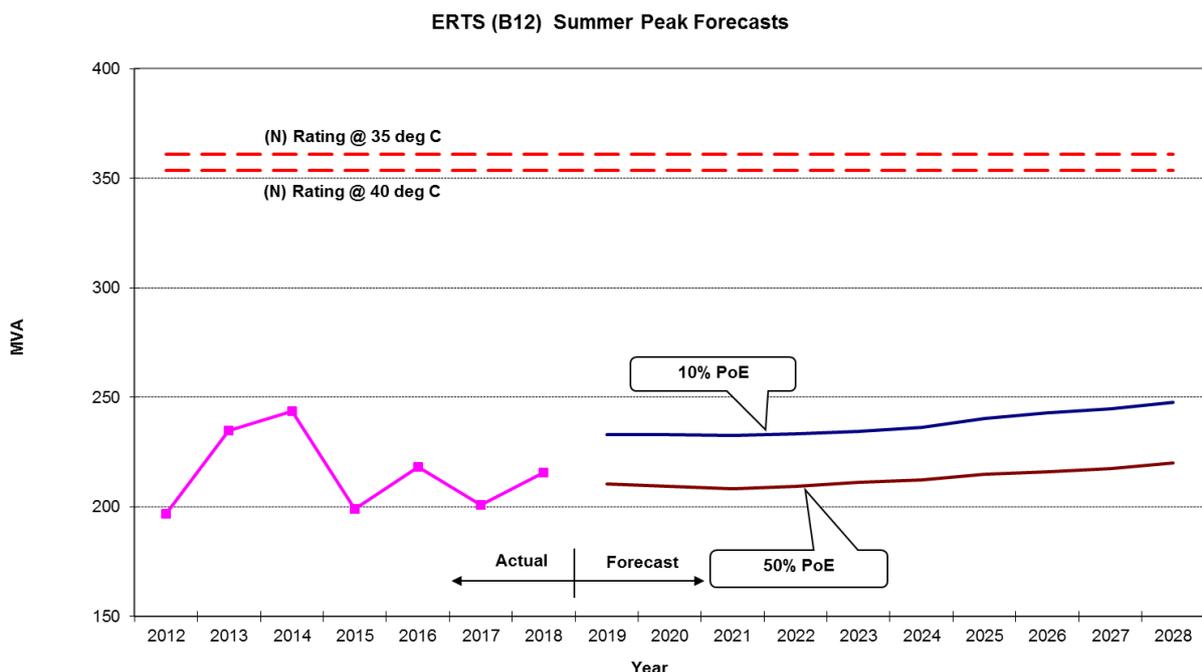
In the event of a transformer outage, the normally open 66 kV bus tie circuit breaker will automatically be closed to share the demand across the other three transformers. The following sections discuss the demand on these two bus groups under normal operating conditions.

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

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

The graph below depicts the ERTS (B12) bus group rating with both transformers in service (“N” rating), the historical demand and the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecasts.

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



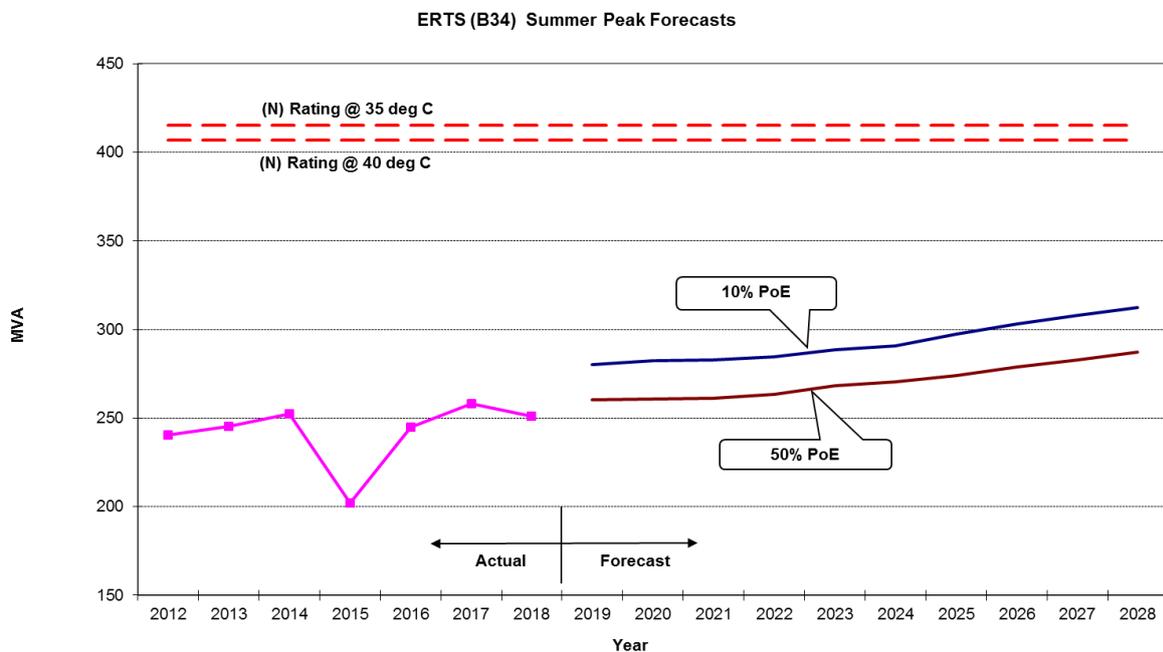
### Transformer group ERTS (B34) Summer Peak Forecasts

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

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

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

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



oad at ERTS remains below the “N-1” rating under both 10<sup>th</sup> percentile and 50<sup>th</sup> percentile maximum demand forecasts for the ten year planning period. Further, load at both bus groups remains below their respective N ratings within the ten year planning period. Therefore, on the basis of the current forecasts, there is not expected to be any need for augmentation over the ten year planning period.

## EAST ROWVILLE TERMINAL STATION 66 kV

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

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

Station: ERTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	461	461	460	464	470	473	480	486	491	498
50th percentile Winter Maximum Demand (MVA)	388	392	396	399	402	408	414	419	424	313
10th percentile Summer Maximum Demand (MVA)	503	506	506	509	514	518	528	537	543	551
10th percentile Winter Maximum Demand (MVA)	395	399	403	406	409	415	421	426	431	320
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									
Expected Unserved Energy value at 10th percentile demand	\$0.0k									
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$0.0k									

#### Notes:

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

## FISHERMAN’S BEND TERMINAL STATION 66 kV (FBTS 66 kV)

FBTS 66 kV is a terminal station shared by both CitiPower (currently 92.8%) and Powercor (currently 7.2%). 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 38,582 customers in the areas of Docklands, Southbank, Port Melbourne, Fisherman’s Bend, Albert Park, Middle Park, St Kilda West and the south west corner of the CBD.

As part of its asset renewal program, AusNet Transmission Group plans to replace the B4 transformer with a new 150 MVA 220/66 kV transformer unit by 2020.

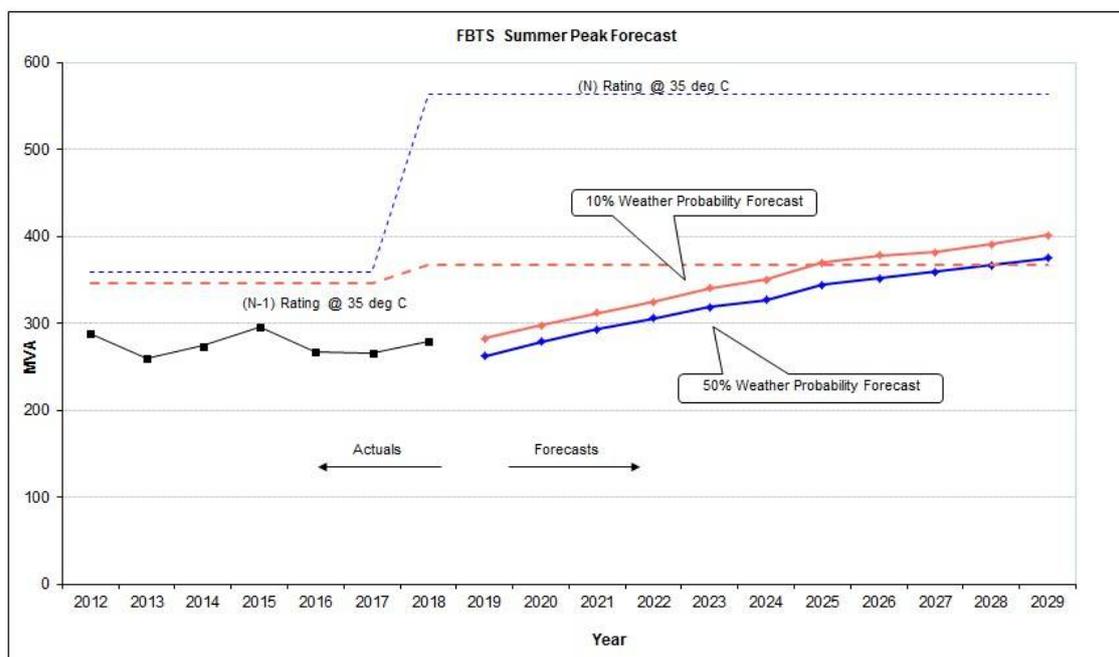
The peak load on the station reached 278.6 MW in summer 2018. It is estimated that:

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

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

AEMO decided to retire the 125 MVA synchronous compensator at FBTS in 2015 and the station is now operating with all three 220/66 kV transformers in service under system normal conditions. Previously the station was run with one transformer operating on “Normal Open Auto Close” duty for fault level mitigation. AusNet Services has updated the terminal station ratings to reflect this change. The updated ratings shown in the graph below also reflect the permanent replacement of the failed B1 transformer unit with the metropolitan spare transformer, which occurred in late 2016.

The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile maximum demand forecasts during the summer periods over the next ten years, together with the station’s operational N and N-1 ratings. The forecast demand includes the effects of any future load transfer works that have been committed.



The graph shows that there would be sufficient capacity at FBTS 66 kV to supply all expected load over the forecast period until 2028, even with one transformer out of service under 50<sup>th</sup> percentile forecast conditions. Under 10<sup>th</sup> percentile forecast conditions, there is some load at risk from 2025. CitiPower expects that any such load at risk will be managed through load transfers or other cost-effective operational measures. The alternative would be to install a 4<sup>th</sup> 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 the fourth transformer at that time. Therefore, the need for augmentation is not expected to arise over the next ten years.

## FRANKSTON TERMINAL STATION (FTS)

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

United Energy upgraded its existing CBTS-CRM 66 kV line in 2009. This increased the summer thermal rating of the line from 930 A to 1120 A at 35°C. Also 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.

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.

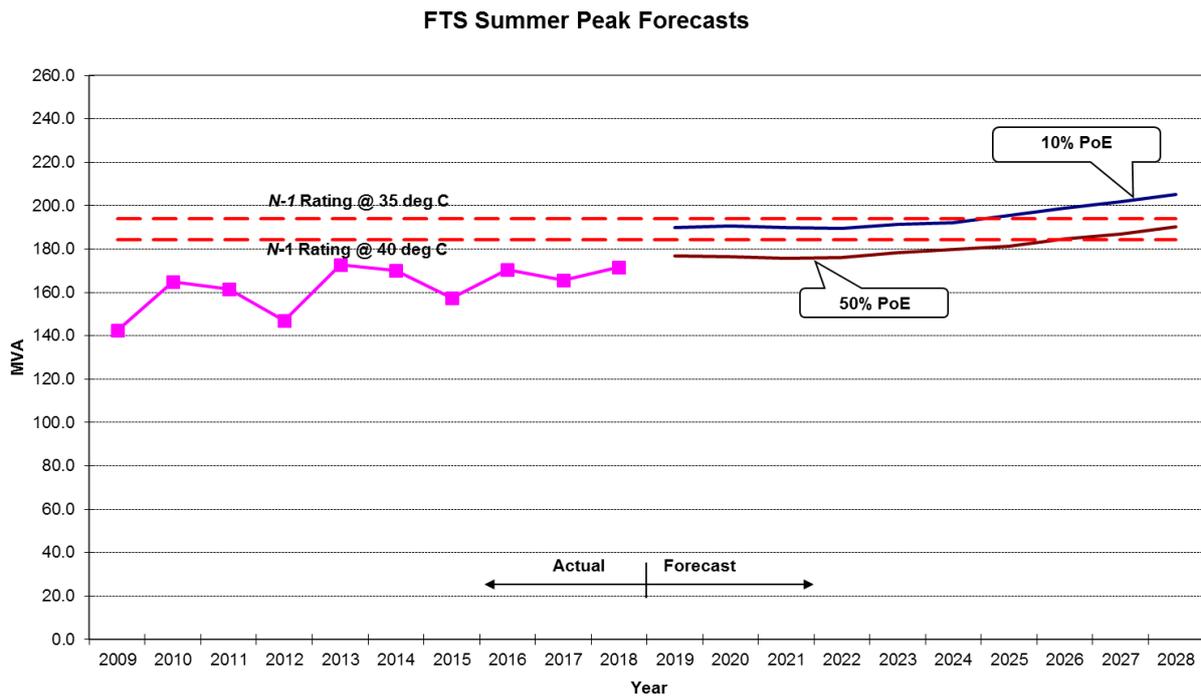
66kV Supply Route to FTS	Thermal Rating @ 35°C	Dynamic Rating @ 35°C	Ownership
CBTS-FTS #1	825 Amp	825 Amp @ 1.2m/s 920 Amp @ 2.2m/s	Transmission connection asset owned by AusNet Transmission Group
CBTS-FTS #2	825 Amp	825 Amp @ 1.2m/s 920 Amp @ 2.2m/s	Transmission connection asset owned by AusNet Transmission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

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

The various 66 kV supply routes and ownership arrangements mean that the risk assessment for FTS is more complicated than for other terminal stations. As far as transmission connection assets are concerned, load flow studies indicate that the lowest (N-1) rating of FTS during summer corresponds to the outage of either of the CBTS-FTS No.1 or CBTS-FTS No.2 66 kV lines which are limited by the thermal rating of the CBTS-CRM 66 kV line. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station's operational (N-1) rating at 35°C as well as 40°C ambient temperature.

The (N-1) rating on the chart below indicates the maximum load that can be supplied from FTS with the CBTS-FTS No.1 or No.2 66 kV line out of service.

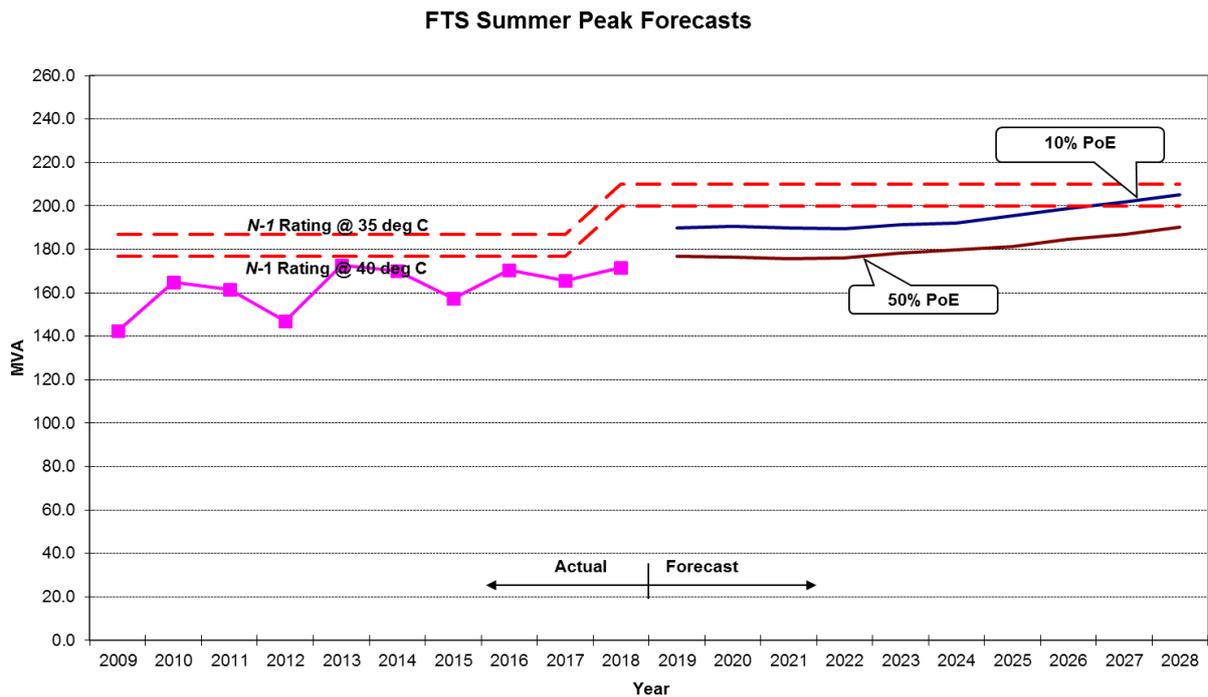
<sup>1</sup> The maximum demand forecast adopted in this risk analysis excludes the impact of embedded generation scheme.



The graph indicates that the 10<sup>th</sup> percentile overall summer maximum demand at FTS 66 kV is expected to exceed the (N-1) rating at 40°C from summer 2019 while the 50<sup>th</sup> percentile summer maximum demand is not forecast to exceed the station’s (N-1) rating in the ten year period.

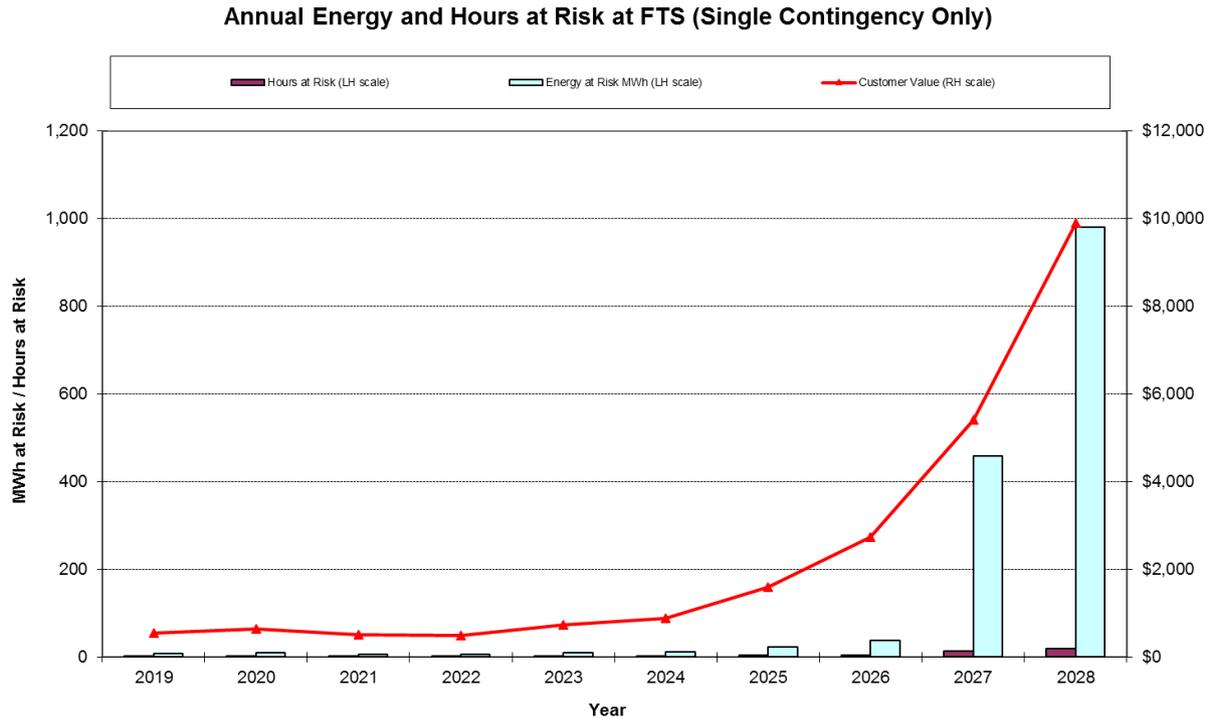
It should be noted that if the CBTS-FTS 66 kV lines (owned and operated by AusNet Transmission Group) become overloaded, AusNet Transmission Group’s centralised automatic load shedding scheme (SOCS) would be initiated to trip both lines. This would result in loss of electricity supply to all customers connected at FTS until the lines are re-energised with sufficiently reduced demand level to avoid further overloading.

The maximum loading on the CBTS-FTS 66 kV lines would occur for an outage of the CBTS-CRM 66 kV line. Based on the current forecast the 10<sup>th</sup> percentile overall summer maximum demand at FTS 66 kV is expected to exceed the (N-1) rating at 40°C from summer 2027 while the 50<sup>th</sup> percentile summer maximum demand is not forecast to exceed the station’s (N-1) rating in the ten year period. This is shown in the graph below.



The station load is forecast to have a power factor of 0.963 at times of peak demand. The demand at FTS is expected to exceed 95% peak demand for approximately 13 hours per annum. There is approximately 41 MVA of load transfer available for the loop for summer 2018/19.

The bar chart below depicts the energy at risk for the 10<sup>th</sup> percentile demand forecast, and the hours per year that the 10<sup>th</sup> 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 10<sup>th</sup> percentile demand forecast.



**Comments on Energy at Risk**

As noted above, for an outage of the CBTS-FTS No.1 or No.2 66 kV line, there is insufficient capacity at FTS to supply all the connected demand at the 10<sup>th</sup> percentile temperature from 2019 onwards. There is sufficient capacity at FTS to supply all the connected demand at the 50<sup>th</sup> percentile temperature for the 10 year planning period.

By the end of the ten year planning period, the total estimated duration of the constraint under N-1 is about 19 hours in 2028. The total energy at risk is estimated to be 980 MWh in summer 2028. The estimated value to consumers of the 980 MWh of energy at risk is approximately \$37.4 million (based on a value of customer reliability of \$38,138/MWh)<sup>2</sup>.

The expected unavailability of CBTS-FTS No.1 or No.2 66kV sub-transmission line per annum due to a major outage is 0.375% per annum. The expected unavailability of CBTS-CRM 66kV sub-transmission line per annum due to a major outage is 0.007% per annum. When the energy at risk (980 MWh in 2028) is weighted by these low unavailabilities, the expected unserved energy is estimated to be around 0.3 MWh. This expected unserved energy is estimated to have a value to consumers of around \$9,900 (based on a value of customer reliability of \$38,138/MWh).

The key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

<sup>2</sup> The value of unserved energy is derived from the sector values given in Table 1 in Section 2.3, weighted in accordance with the composition of the load at this terminal station.

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0	\$0.0M
Expected unserved energy at 50 <sup>th</sup> percentile demand	0	\$0.0M
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	980	\$37.4 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	0.3	\$9,900

With dynamic ratings now implemented on the CBTS-FTS 66kV lines, the energy at risk is minimal within the 10 year planning period. Therefore, no further works to address load at risk are expected to be required over the ten year planning horizon.

## FRANKSTON TERMINAL STATION 66 kV

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

**Distribution Businesses supplied by this station:** United Energy (100%)  
**Normal cyclic rating with all plant in service** 251 MVA via all 66kV lines (Summer peaking)  
 210 MVA and 194 MVA for an outage of CBTS-CRM and CBTS-FTS #1 or #2 lines respectively [See Note 1 below for interpretation of N-1]  
**Summer N-1 Loop Rating:**  
**Winter N-1 Loop Rating:** 247 MVA and 201 MVA for an outage of CBTS-CRM and CBTS-FTS #1 or #2 lines respectively

Station: FTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	177	177	176	176	178	180	181	185	187	190
50th percentile Winter Maximum Demand (MVA)	134	136	138	140	142	145	148	151	154	156
10th percentile Summer Maximum Demand (MVA)	190	191	190	190	191	192	195	199	202	205
10th percentile Winter Maximum Demand (MVA)	136	138	140	142	144	147	150	153	156	159
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)	8	9	7	7	10	12	22	38	459	980
N-1 hours at risk at 10th percentile demand (hours)	2	2	2	2	2	3	5	5	14	19
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	0.1	0.3
Expected Unserved Energy value at 50th percentile demand	\$0.0K									
Expected Unserved Energy value at 10th percentile demand	\$0.6K	\$0.7K	\$0.5K	\$0.5K	\$0.7K	\$0.9K	\$1.6K	\$2.7K	\$5.4K	\$9.9K
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$0.2K	\$0.2K	\$0.2K	\$0.1K	\$0.2K	\$0.3K	\$0.5K	\$0.8K	\$1.6K	\$3.0K

#### Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.3, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50<sup>th</sup> and 10<sup>th</sup> percentile expected unserved energy estimates (respectively) is in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))

## GEELONG TERMINAL STATION (GTS) 66 kV

Geelong Terminal Station (GTS) 66 kV consists of four 150 MVA 220/66 kV transformers. Due to the excessive fault levels associated with all four transformers operating in parallel the following strategies have been adopted:

- (a) Prior to 2012 the B3 transformer operated as a hot standby with a normally open auto close scheme on its 66 kV circuit breaker.
- (b) In 2012 the 66 kV loop lines were rearranged so that the B3 transformer could be placed in service with the 66 kV bus tie circuit breaker between 66 kV buses 2&3 normally open. Under system normal, 66 kV buses 1&2 are supplied via B1 and B2 transformers and 66 kV buses 3&4 are supplied via B3 and B4 transformers. For loss of a transformer, the normally open 66 kV bus tie circuit breaker between buses 2&3 is closed. This measure increased the N-1 capacity significantly as shown in the total station load forecast graph below. The GTS N-1 summer rating is 524 MVA.
- (c) As part of the AusNet Transmission Group asset renewal program, the B3 transformer was replaced in 2013, and the B1 transformer was replaced in 2014. These works increased the terminal station's capacity slightly as reflected in the total load forecast graph below.

GTS is the main source of supply for over 151,261 customers in Geelong and the surrounding area. The station supply area includes Geelong, Corio, North Shore, Drysdale, Waurin Ponds and the Surf Coast.

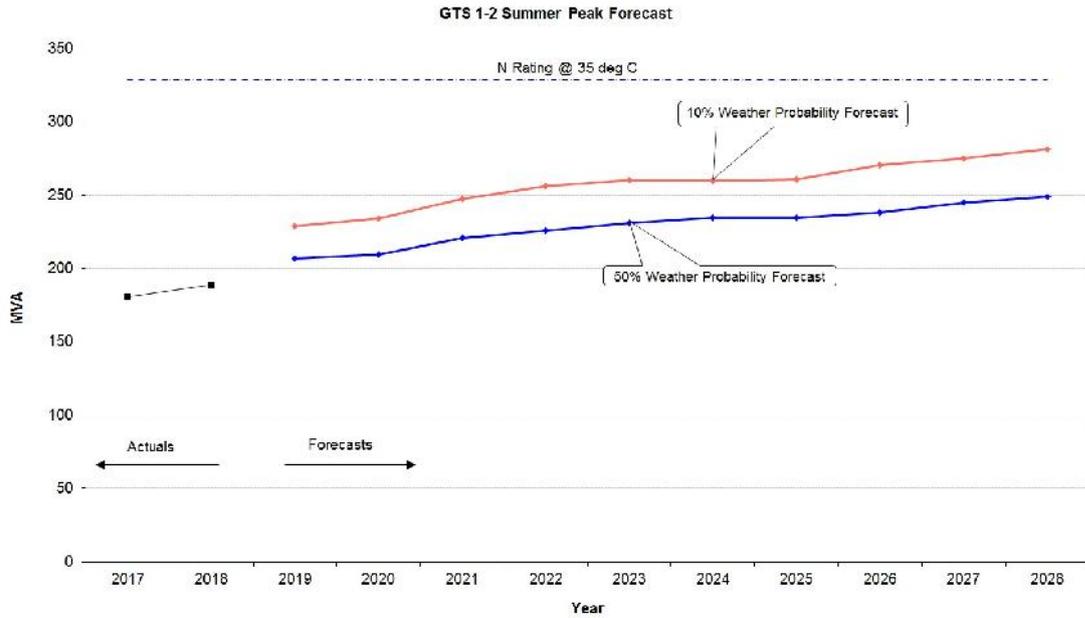
Due to the operating arrangement at this station, load comparisons with the N rating are provided against the separate bus groups below, followed by comment on load comparisons against the N-1 rating shown in the overall station graph.

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

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

The peak load on the GTS 1 & 2 Bus group reached 184.9 MW (188.7 MVA) in summer 2018.

GTS 66 kV buses 1&2 demand is summer peaking. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service).

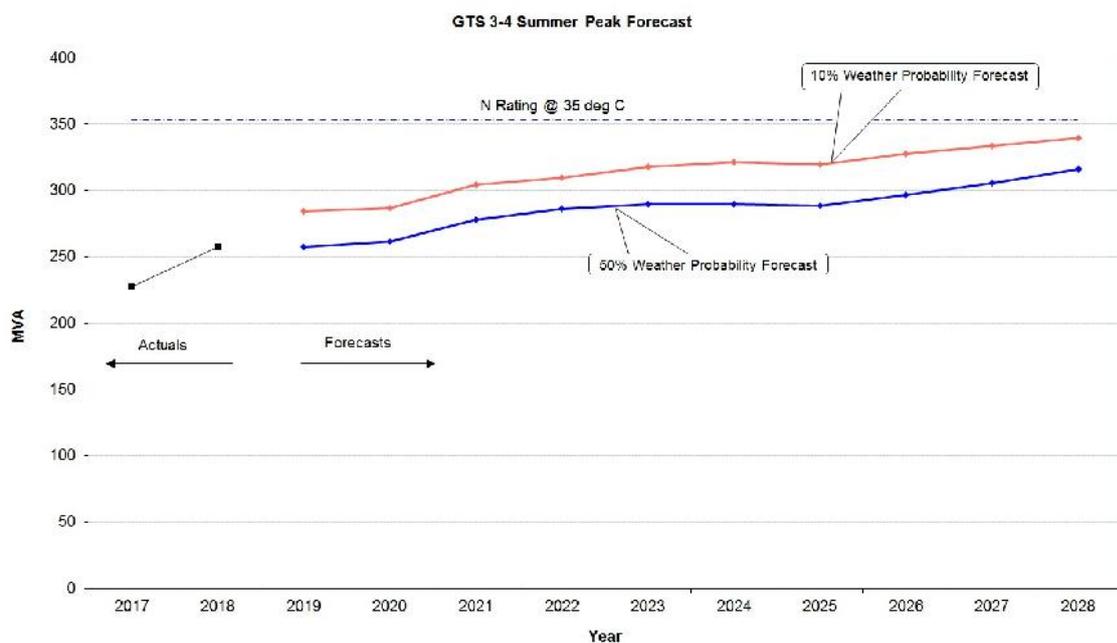


The (N) rating on the chart indicates the maximum load that can be supplied from GTS bus 1&2 with two transformers in service. The graph shows there is sufficient capacity (N rating) at the station to supply all expected load over the forecast period.

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

This bus group supplies Powercor’s zone substations at Geelong East, Geelong City, Geelong B, Corio and 66kV customer substation Ford Norlane. The peak load on the GTS 3 & 4 Bus group reached 246.3 MW (257.3 MVA) in summer 2018.

GTS 66 kV buses 3&4 demand is summer peaking. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service).



The (N) rating on the chart indicates the maximum load that can be supplied from GTS bus 3&4 with two transformers in service. The graph shows there is sufficient capacity (N rating) at the station to supply all expected load over the forecast period.

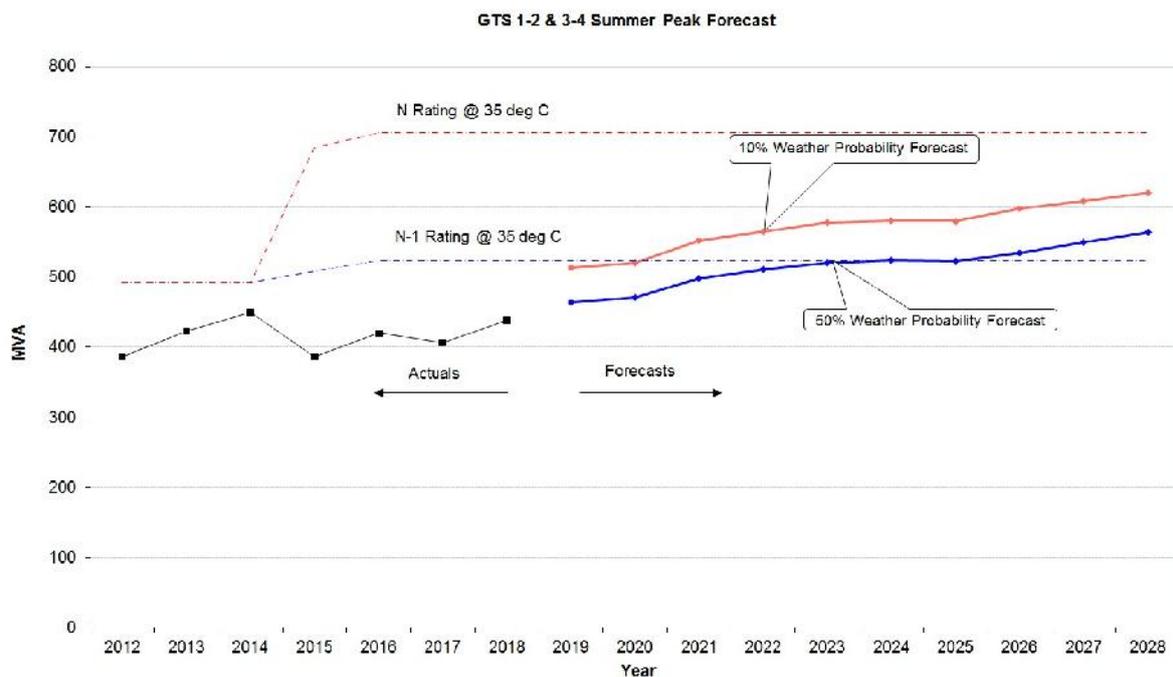
**GTS Total Load Summer Peak Forecasts**

Growth in summer peak total demand at GTS has averaged around 2.7 MW (1.03%) per annum over the last 5 years. The peak total load on the station reached 427.8 MW (438.5 MVA) in Summer 2018.

It is estimated that:

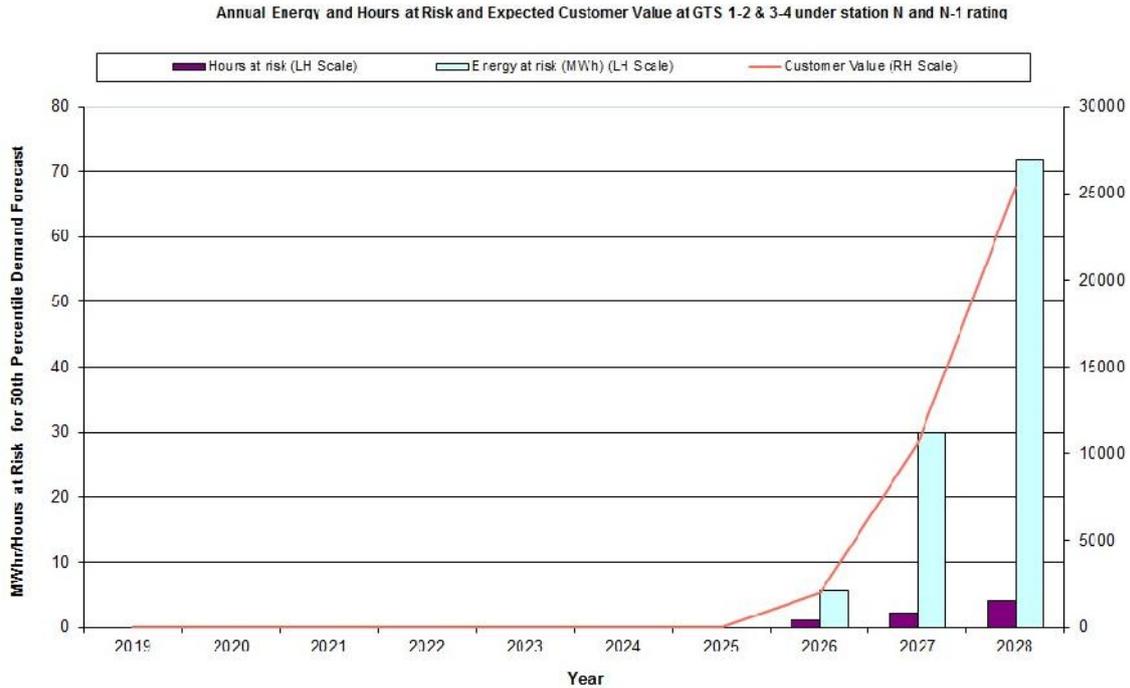
- For 13 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile forecast.
- The station load power factor at the time of peak demand is 0.98

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



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

The bar chart below depicts the energy at risk with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours per year that the 50<sup>th</sup> 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 50<sup>th</sup> percentile demand forecast.



### Comments on Energy at Risk

For an outage of one transformer at GTS, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 4 hours in 2028. The energy at risk at the 50<sup>th</sup> percentile temperature under N-1 conditions is estimated to be 71.8 MWh in 2028. The estimated value to consumers of the 71.8 MWh of energy at risk is approximately \$3 million (based on a value of customer reliability of \$40,703 per MWh).<sup>1</sup> In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at GTS in 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$3 million.

It is emphasised however, that the probability of a major outage of one of the four transformers occurring over the year is very low at about 1.0% per transformer per annum, while the expected unavailability per transformer per annum is 0.217%. When the energy at risk (71.8 MWh for 2028) is weighted by this low unavailability, the expected unserved energy is estimated to be 0.62 MWh. This expected unserved energy is estimated to have a value to consumers of around \$25,300 (based on a value of customer reliability of \$40,703 per MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2028 is estimated to be 605.7 MWh. The estimated value to consumers of this energy at risk in 2028 is approximately \$24.7 million. The corresponding value of the expected unserved energy (of 5.25 MWh) is \$213,700.

<sup>1</sup> 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.

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

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	71.8	\$3 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	0.62	\$25,300
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	605.7	\$24.7 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	5.25	\$213,700

### Feasible options for alleviation of constraints

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

- Installation of a fifth 220/66 kV transformer (150 MVA) at TGTS at an indicative capital cost of \$18 million.
- Demand reduction: There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction would depend on the customer uptake and would be taken into consideration when determining the optimum timing for any future capacity augmentation.
- Embedded generation: There is a committed wind farm, Mt Gellibrand wind farm (132 MW) which will be commissioned in 2019 and some portion of this generation capacity will contribute into 66 kV infrastructure ex-GTS. This may defer the need for any capacity augmentation at GTS.
- 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 GTS, it is proposed to:

1. Install a fifth 220/66 kV transformer (150 MVA) at GTS at an indicative capital cost of \$18 million. This equates to a total annual cost of approximately \$1.04 million per annum. On the basis of the medium economic growth scenario and both 50<sup>th</sup> and 10<sup>th</sup> percentile weather probability, the transformer would not be expected to be required before 2028 to support the critical peak demand.
2. As a temporary measure, maintain contingency plans to transfer load quickly to TGTS by the use of the 66 kV tie lines between TGTS and GTS in the event of an unplanned outage of one transformer at GTS under critical loading conditions. This load transfer is

in the order of 10 MVA. Under these temporary measures, affected customers would be supplied from the 66 kV tie line infrastructure on a radial network, thereby reducing their level of reliability.

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

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

## Geelong Terminal Station

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

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

#### MVA

Normal cyclic rating with all plant in service 332

via 2 transformers (summer)

Summer N-1 Station Rating: 166

[See Note 1 below for interpretation of N-1]

Winter N-1 Station Rating: 185

Station: GTS 1-2 & 3-4	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	463.6	470.7	497.6	511.3	520.0	523.3	522.4	534.0	549.8	564.2
50th percentile Winter Maximum Demand (MVA)	433.4	443.3	460.2	472.0	479.3	482.7	486.3	495.4	506.8	521.6
10th percentile Summer Maximum Demand (MVA)	512.9	520.1	551.4	565.2	577.5	580.1	579.5	597.3	608.3	620.1
10th percentile Winter Maximum Demand (MVA)	409.7	422.9	430.6	437.2	442.5	453.3	460.8	466.4	473.5	505.9
N-1 energy at risk at 50% percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7	29.9	71.8
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	2.3	4.0
N-1 energy at risk at 10% percentile demand (MWh)	0.0	0.0	33.7	75.5	135.9	152.6	148.6	299.4	429.9	605.7
N-1 hours at risk at 10th percentile demand (hours)	0.0	0.0	2.5	4.0	5.8	6.3	6.3	10.8	13.5	17.8
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.26	0.62
Expected Unserved Energy at 10th percentile demand (MWh)	0.00	0.00	0.29	0.65	1.18	1.32	1.29	2.59	3.73	5.25
Expected Unserved Energy value at 50th percentile demand	\$0.00M	\$0.01M	\$0.03M							
Expected Unserved Energy value at 10th percentile demand	\$0.00M	\$0.00M	\$0.01M	\$0.03M	\$0.05M	\$0.05M	\$0.05M	\$0.11M	\$0.15M	\$0.21M
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	\$0.01M	\$0.01M	\$0.02M	\$0.02M	\$0.03M	\$0.05M	\$0.08M

#### Notes:

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

## 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.

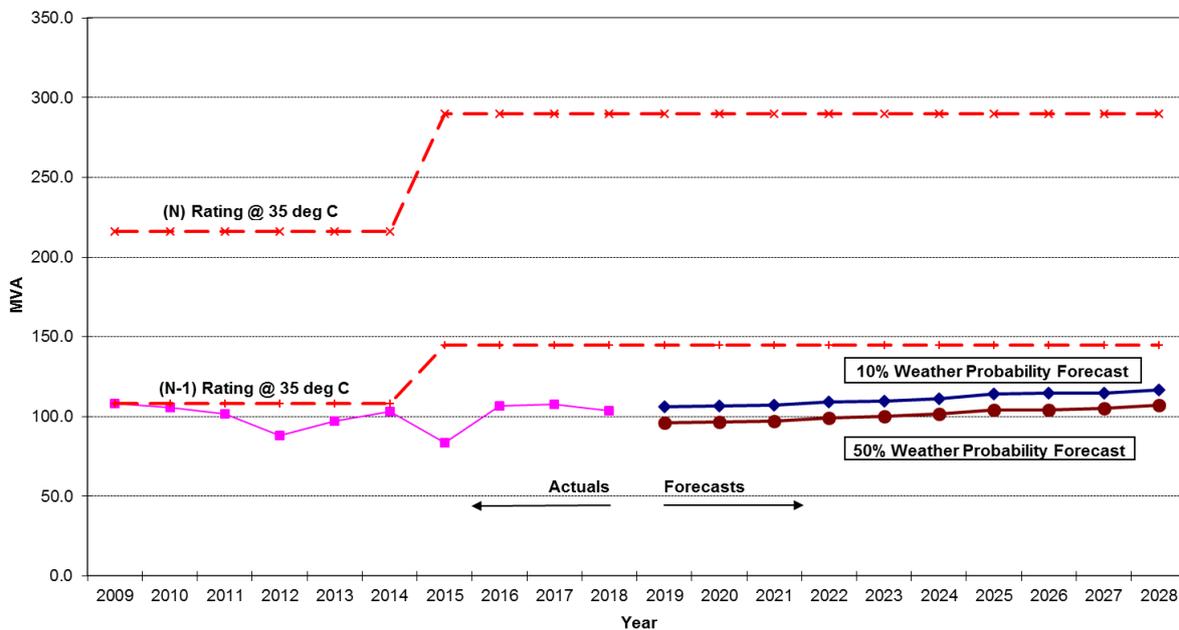
### Magnitude, probability and impact of loss of load

GNTS has historically been a winter peaking station, but more recently has had similar peak loading in summer and winter. The rate of growth in summer and winter peak demand at GNTS 66 kV has been low in recent years, and demand is forecast to continue increasing slowly, averaging around 1% per annum for the 10 year planning horizon.

The peak load on the station reached 101.6 MW (103.8 MVA) in winter 2017 and 98.1 MW (103.7 MVA) in summer 2017/18. The demand at GNTS 66 kV is expected to exceed 95% of the 50<sup>th</sup> percentile peak demand for 5 hours per annum. The station load has a power factor of 0.95 at summer maximum demand.

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

GNTS 66 kV Summer Peak Demand Forecasts



The graph shows that there is no energy at risk under 50<sup>th</sup> percentile or 10<sup>th</sup> percentile loading conditions for the summer period for the next ten years. There is therefore not expected to be any need for augmentation over the ten year planning period.

## HEATHERTON TERMINAL STATION (HTS)

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

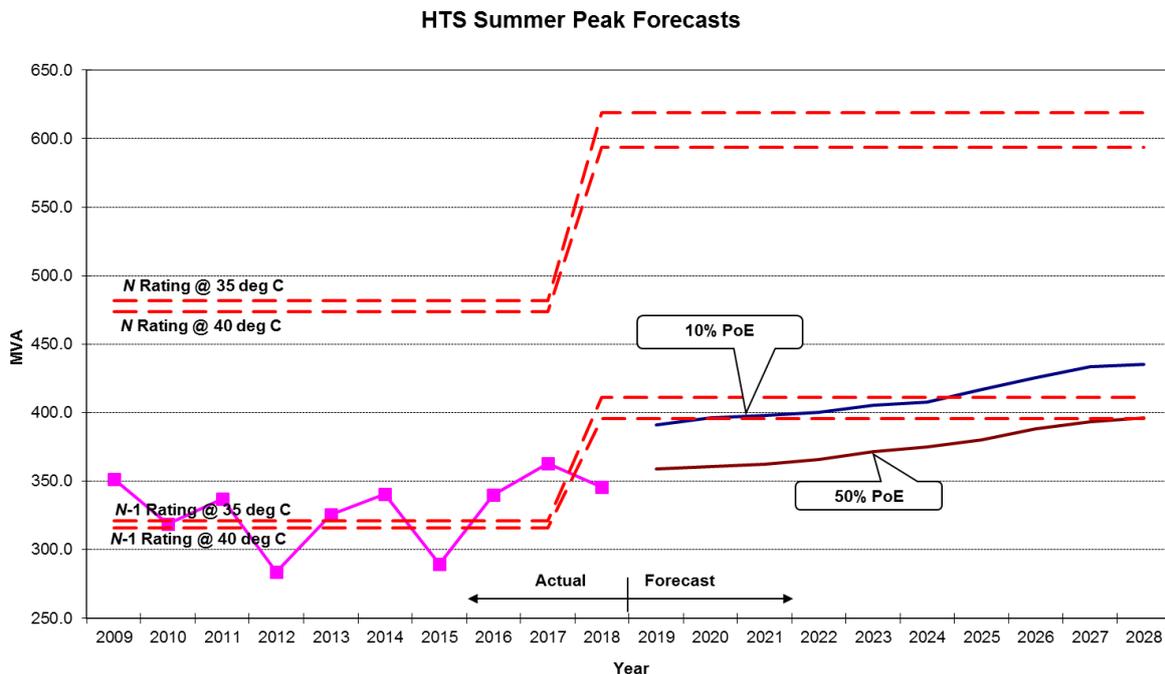
HTS is a summer critical terminal station. The station reached its highest recorded peak demand of 354.0 MW (363 MVA) in summer 2017. The recorded peak demand in summer 2018 was 335.1 MW (346 MVA), which was 19 MW lower than the 2017 peak. There are no embedded generation units over 1 MW connected at HTS.

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

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.

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

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

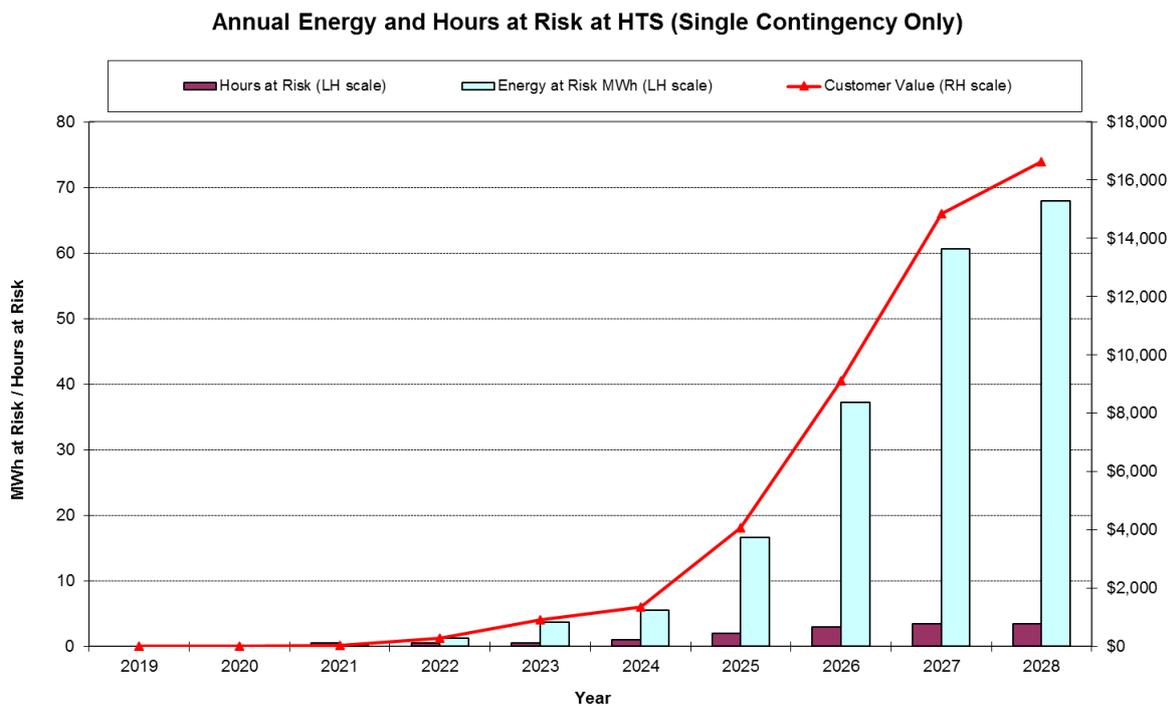


The N rating on the graph indicates the maximum load that can be supplied from HTS with all transformers in service.

The graph indicates that with the increased station rating the 10<sup>th</sup> percentile maximum demand is not expected to exceed the (N-1) rating until summer 2021 and the 50<sup>th</sup> percentile maximum demand is not expected to exceed the (N-1) rating in the 10 year period.

The station load is forecast to have a power factor of 0.970 at times of peak demand. The demand at HTS is expected to exceed 95% of peak demand for approximately 6 hours.

The bar chart below depicts the energy at risk with one transformer out of service for the 10<sup>th</sup> percentile demand forecast, and the hours per year that the 10<sup>th</sup> 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 10<sup>th</sup> percentile demand forecast.



**Comments on Energy at Risk**

For an outage of one transformer at HTS, it is expected that from 2021, there would be insufficient capacity at the station to supply all demand at the 10<sup>th</sup> percentile temperature.

By the end of the ten-year planning period in 2028, the energy at risk under N-1 conditions is estimated to be 68 MWh at the 10<sup>th</sup> percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 4 hours in that year. The estimated value to consumers of the 68 MWh of energy at risk in 2028 is approximately \$2.6 million (based on a value of customer reliability of \$37,927/MWh)<sup>1</sup>. In other words, at the 10<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at HTS over the summer of 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$2.6 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (68 MWh in 2028) is weighted by this low unavailability, the expected unserved energy is estimated to be

<sup>1</sup> 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.

around 0.4 MWh. This expected unserved energy is estimated to have a value to consumers of around \$16,630 (based on a value of customer reliability of \$37,927/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of 10<sup>th</sup> percentile temperatures occurring in each year. Under 50<sup>th</sup> percentile temperature conditions, the energy at risk is expected to be zero in 2028. These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0	\$0.0 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	0.0	\$0
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	68	\$2.6 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	0.4	\$16,630

### 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<sup>2</sup> load shedding scheme which is operated by AusNet Transmission Group's TOC<sup>3</sup> will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy's operational procedures after the operation of the OSSCA scheme.

In the case of HTS supply at maximum loading periods, the OSSCA scheme would shed about 170 MVA of load, affecting up to approximately 48,000 customers.

### 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 subtransmission and 22/11 kV distribution networks. These plans are reviewed annually prior to the summer season. Transfer capability away from HTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 80 MVA for summer 2019.
2. Install a fourth 220/66 kV transformer at HTS.
3. Establish a new 220/66 kV terminal station (DNST) in the Dandenong area to off-load HTS.

<sup>2</sup> Overload Shedding Scheme of Connection Asset.

<sup>3</sup> Transmission Operations Centre

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 a number of other significant sub-transmission and connection asset constraints in the Dandenong, Keysborough and Braeside areas, which a 4<sup>th</sup> 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 subtransmission works is estimated to be in excess of \$70 million with an estimated total annual cost of approximately \$4.1 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**

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

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at HTS under critical loading conditions:
  - maintain contingency plans to transfer load quickly to adjacent terminal stations;
  - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place; and
  - subject to the availability of AusNet Transmission Group's spare 220/66 kV transformer for metropolitan areas (refer to Section 4.5), this spare transformer 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. As explained above, on the present forecasts, the new terminal station in the Dandenong area is unlikely to be economic within the ten year planning horizon.

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

## HEATHERTON TERMINAL STATION 66 kV

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

**Distribution Businesses supplied by this station:** United Energy (100%)  
**Station operational rating (N elements in service):** 619 MVA via 3 transformers (Summer peaking)  
**Summer N-1 Station Rating:** 411 MVA [See Note 1 below for interpretation of N-1]  
**Winter N-1 Station Rating:** 434 MVA

Station: HTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	359	361	363	366	372	375	380	388	393	396
50th percentile Winter Maximum Demand (MVA)	261	262	263	262	263	265	267	270	272	273
10th percentile Summer Maximum Demand (MVA)	391	396	398	400	405	408	417	426	433	435
10th percentile Winter Maximum Demand (MVA)	265	266	267	266	267	270	272	275	277	279
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	4	5	17	37	61	68
N-1 hours at risk at 10th percentile demand (hours)	0	0	1	1	1	1	2	3	4	4
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.39	0.4
Expected Unserved Energy value at 50th percentile demand	\$0.00M									
Expected Unserved Energy value at 10th percentile demand	\$0.00M	\$0.01M	\$0.01M	\$0.02M						
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$0.00M									

#### Notes:

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

## 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 36,411 customers in Horsham and the surrounding area. The station supply area includes Horsham, Edenhope, Warracknabeal and Nhill. The station also supplies Stawell via the inter-terminal 66 kV ties with Ballarat Terminal Station (BATS).

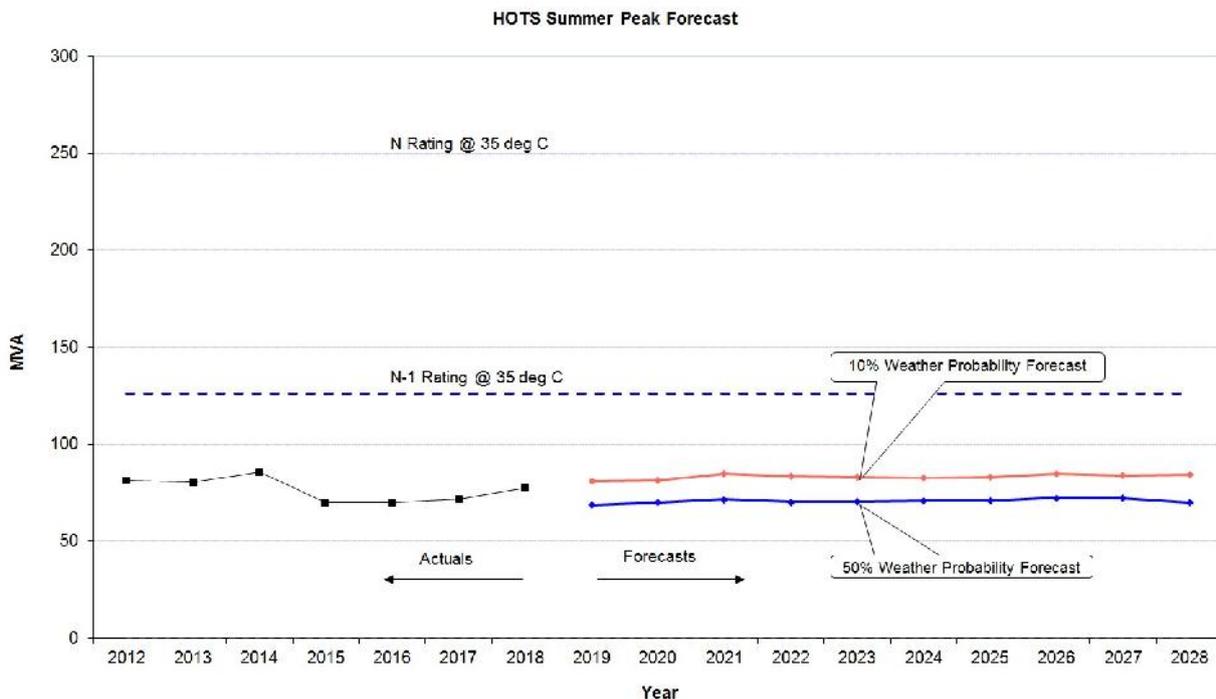
### Magnitude, probability and impact of loss of load

HOTS 66 kV demand is summer peaking. Summer peak demand at HOTS has increased by an average of around 0.003 MW (0.29%) per annum over the last 5 years. The peak load on the station reached 77.4 MW in summer 2018.

It is estimated that:

- For 3 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile forecast.
- The station load power factor at the time of peak demand is 0.99.

The graph depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature.



The graph shows there is sufficient capacity at the station to supply all expected load over the forecast period, even with one transformer out of service under 50<sup>th</sup> and 10<sup>th</sup> percentile forecast conditions. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

## HEYWOOD TERMINAL STATION (HYTS) 22 kV

Heywood Terminal Station (HYTS) 22 kV consists of two 70 MVA 500/275/22 kV transformers and is the source of supply to an industrial customer in the local area and the only large customer supplied from this supply point. Another 169 small domestic and farming customers along the line route are also supplied from this supply point.

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

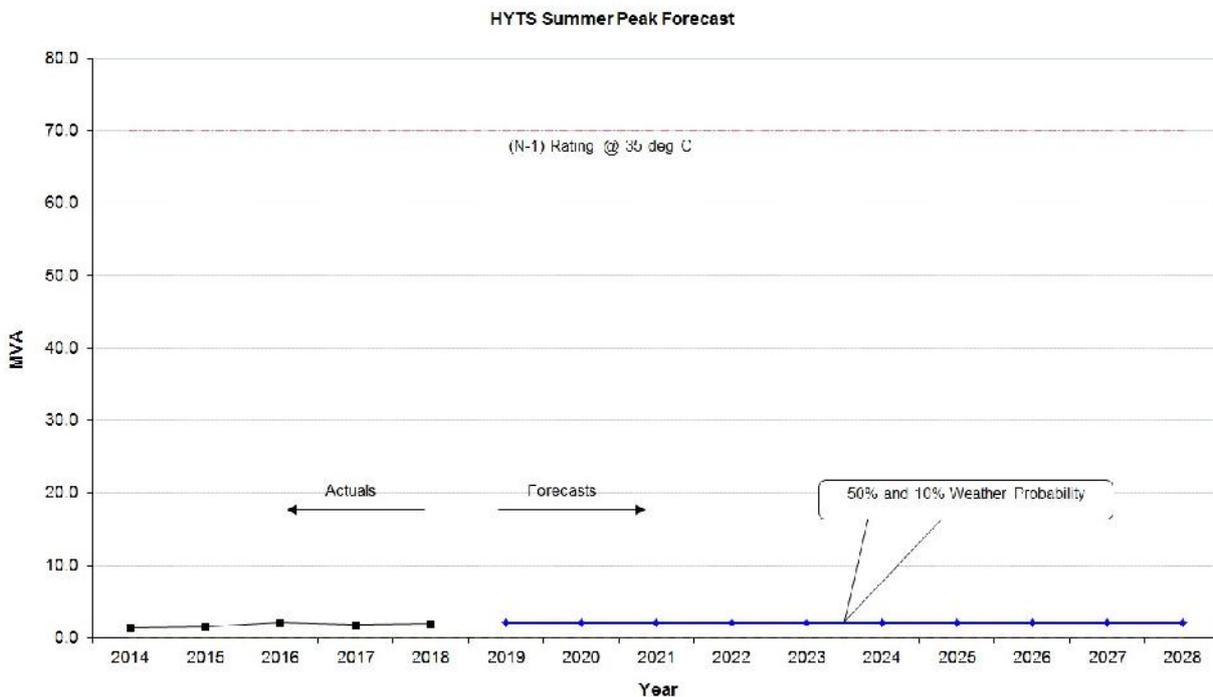
The peak load on the station reached 1.7 MW (1.8 MVA) in summer 2018.

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.

It is estimated that:

- For 10 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile forecast.
- The station load power factor at time of peak demand is 0.96.

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



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

## KEILOR TERMINAL STATION 66 kV (KTS 66 kV)

Keilor Terminal Station is located in the north west of Greater Melbourne. It operates at 220/66 kV and currently supplies a total of approximately 180,500 customer in Jemena Electricity Networks and Powercor in the Airport West, St. Albans, Woodend, Pascoe Vale, Essendon and Braybrook areas.

### Background

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

In 2012, the station was re-configured to enable the KTS B5 transformer to take load under system normal conditions. Under system normal conditions, the No.1, No.2 & No.5 transformers are operated in parallel as one group (KTS (B1,2,5)) and supply the No.1, No.2 & No.5 66 kV buses. The No.3 & No.4 transformers are operated in parallel as a separate group (KTS (B3,4)) and supply the No.3 & No.4 66 kV buses. The 66 kV bus 3-5 and bus 1-4 tie circuit breakers are operated in the normally open position to limit the maximum prospective fault levels on the five 66 kV buses to within switchgear ratings.

For an unplanned transformer outage in the KTS (B3,4) group, the No.5 transformer will automatically change over to the KTS (B3,4) group. Therefore, an unplanned transformer outage of any one of the five transformers at KTS will result in both the KTS (B1,2,5) and KTS (B3,4) groups being comprised of two transformers each. Given this configuration, load demand on both the KTS(B3,4) and KTS (B1,2,5) groups must be kept within the capabilities of two transformers at all times or load shedding will occur.

The following sections examine the two transformer groups separately.

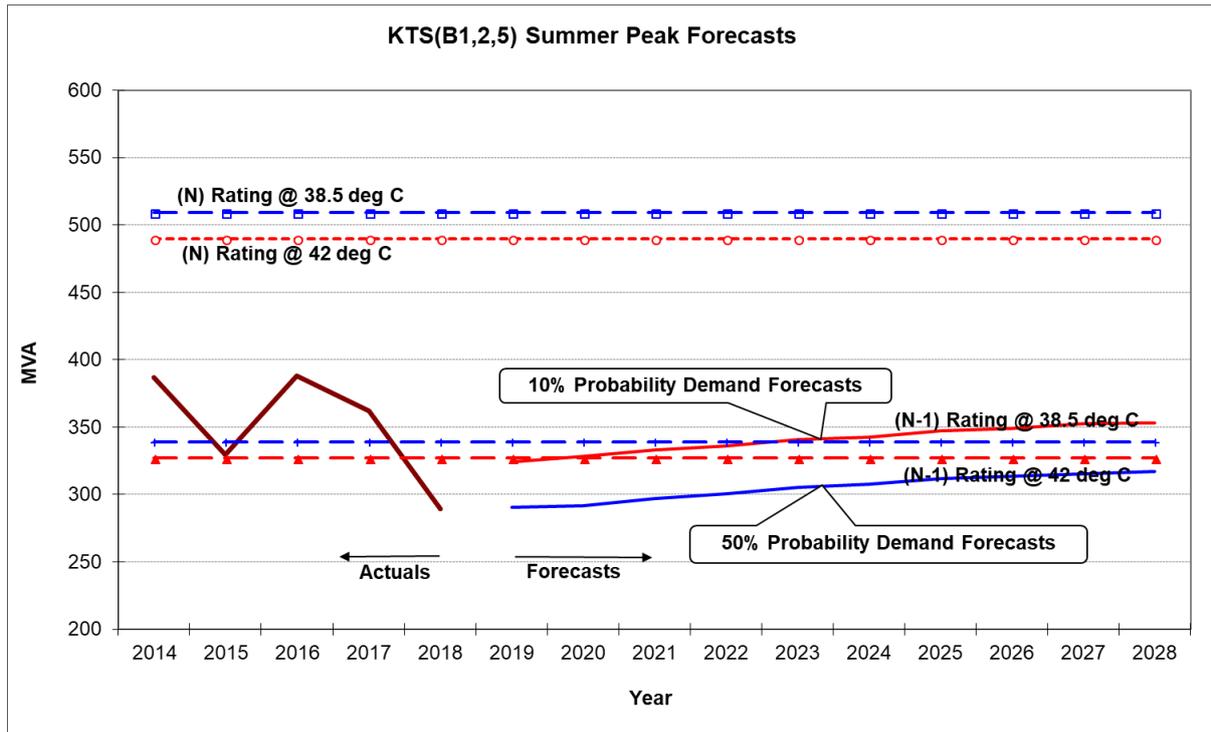
### Transformer group KTS (B1,2,5) Summer Peak Forecasts

The peak load on KTS (B1,2,5) reached 288.8 MW (or 289.0 MVA) in summer (January) 2018.

The graph below depicts the KTS (B1,2,5) rating with all transformers (B1, B2 & B5) in service (“N” rating), and with one of the three transformers out of service (“N-1” rating), along with the 50<sup>th</sup> and 10<sup>th</sup> percentile summer maximum demand forecasts<sup>1</sup>. The recent transfer of load from KTS to DPTS is reflected in the load forecasts shown below.

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<sup>1</sup> Note that station transformer output capability rating and transformer loading are shown in the graph.



The above graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand for the entire forecast period. However, under N-1 condition during peak demand (at the 10<sup>th</sup> percentile temperature) the forecast load is greater than the N-1 rating of KTS (B1,2,5), which could affect some customers.

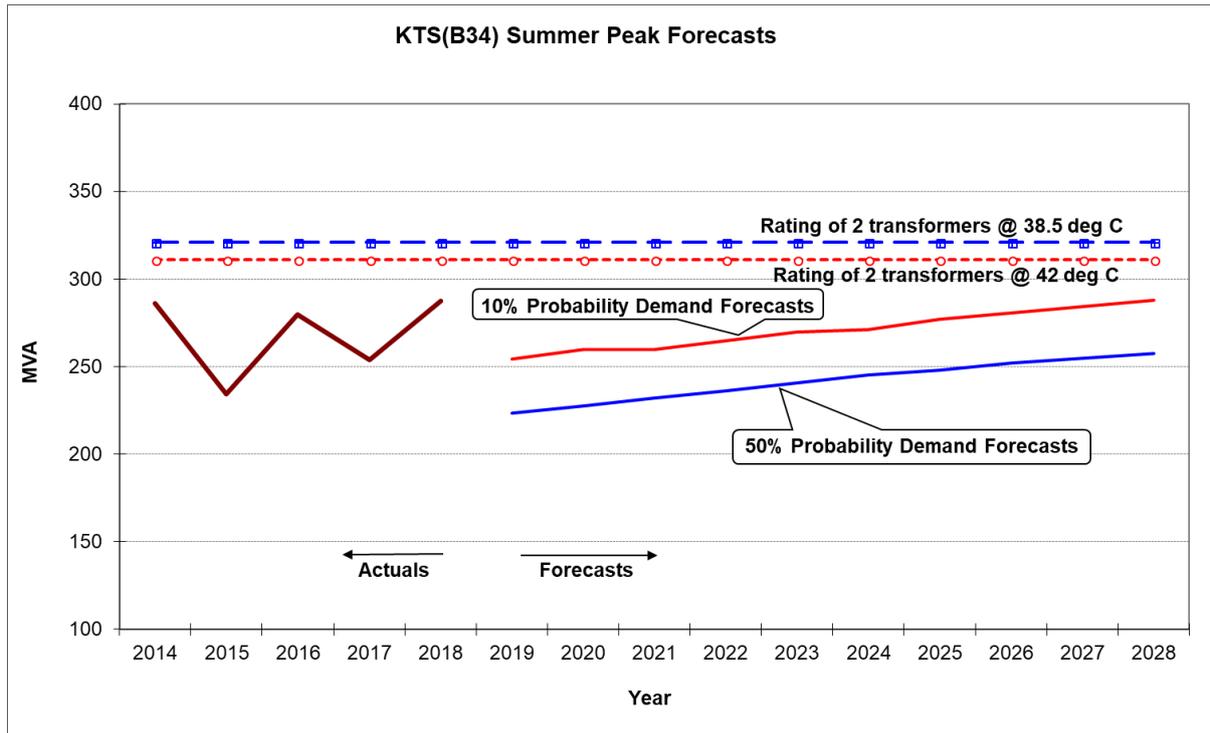
### Transformer group KTS (B3,4) Summer Peak Forecasts

The peak load on KTS (B3,4) reached 273.2 MW (or 287.3 MVA) in summer 2018 (January).

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

It shows that with all transformers in service, there will be sufficient capacity to meet the anticipated maximum load demand for the entire forecast period. The new Deer Park Terminal Station (DPTS) was commissioned in September 2017 and has off-loaded the KTS (B3,4) group.

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



**Comments on Energy at Risk at KTS**

At the 10<sup>th</sup> percentile level, the demand forecast is expected to be below the N capability rating for the entire forecast period. There is no load at risk at under N-1 condition at both KTS (B1,2,5) and KTS (B3,4) at the 50<sup>th</sup> percentile demand forecast.

However, under 10<sup>th</sup> percentile summer temperature conditions, the customer demand increases significantly due to air conditioning loads and there will be a small amount of energy at risk (1.8 MWh in 2020) at KTS (B1,2,5).

The energy at risk at KTS (B1,2,5) increases gradually over the ten year forecast period, to 212 MWh in 2028 at the 10<sup>th</sup> percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 17 hours in that year. The estimated value to customers of the 212 MWh of energy at risk in 2028 is approximately \$8.42 million (based on a value of customer reliability of \$39,710/MWh). In other words, at the 10<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at KTS (B1,2,5) over the summer of 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$8.42 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (212 MWh in 2028) is weighted by this low unavailability, the expected unserved energy is estimated to be around 2.3 MWh. This expected unserved energy is estimated to have a value to consumers of around \$91,200 (based on a value of customer reliability of \$39,710/MWh).

These key statistics for 2028 under N-1 outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0	\$0
Expected unserved energy at 50 <sup>th</sup> percentile demand	0	\$0
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	212	\$8.42 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	2.3	\$91,200

## Possible Impacts on Customers

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

Applying the 10<sup>th</sup> percentile demand forecast, there will be sufficient capacity at the station to supply all customer demand for the entire forecast period under system normal condition.

### N-1 System Condition

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

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

The amount of energy at risk over the 10 year forecast period is insufficient to economically justify capacity augmentation at the station. Over the forecast period, the risk to supply reliability will be mitigated through the following measures:

- Maintain contingency plans to transfer load quickly, where possible, to adjacent terminal stations. Jemena Electricity Networks has up to 44 MVA of load transfer capacity available and Powercor has up to 18 MVA of transfer capacity available.
- Fine-tune the OSSCA scheme settings in conjunction with AusNet Transmission Group to minimise the impact on customers of any automatic load shedding that may take place; and
- Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for urban areas (refer to section 5.5), a spare transformer could be installed at KTS and used to temporarily replace a failed transformer.

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

<sup>2</sup> Overload Shedding Scheme of Connection Asset.

<sup>3</sup> Transmission Operations Centre.

**KEILOR TERMINAL STATION (KTS(B1,2,5) TRANSFORMER GROUP)<sup>4</sup>**

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

Distribution Businesses supplied by this station: Jemena EN (68%), Powercor (32%) (following transfer of load to Deer Park Terminal Station)  
 Normal cyclic rating with all plant in service 509 MVA at 50<sup>th</sup> percentile temperature and 490 MVA at 10<sup>th</sup> percentile temperature (Summer peaking)  
 Summer N-1 Station Transformer Rating: 339 MVA at 50<sup>th</sup> percentile temperature and 327 MVA at 10<sup>th</sup> percentile temperature [See Note 1 below for interpretation of N-1]  
 Winter N-1 Station Transformer Rating: 353 MVA

Station: KTS (B125)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50 <sup>th</sup> percentile Summer Maximum Demand (MVA)	289	290.6	291.8	297.0	300.7	305.4	307.5	311.5	313.7	315.6	317.1
50 <sup>th</sup> percentile Winter Maximum Demand (MVA)	231	232.7	234.3	238.7	242.3	245.0	248.0	250.1	251.9	253.7	255.5
10 <sup>th</sup> percentile Summer Maximum Demand (MVA)	289	324.2	328.4	333.2	335.9	340.5	342.7	347.2	348.8	352.5	353.0
10 <sup>th</sup> percentile Winter Maximum Demand (MVA)	237	240.1	241.3	246.0	249.5	251.8	255.7	257.8	259.1	261.3	262.6
N-1 energy at risk at 50th percentile demand (MWh)	-	-	-	-	-	-	-	-	-	-	-
N-1 hours at risk at 50th percentile demand (hours)	-	-	-	-	-	-	-	-	-	-	-
N-1 energy at risk at 10th percentile demand (MWh)	-	-	2	15	23	52	74	126	149	203	212
N-1 hours at risk at 10th percentile demand (hours)	-	-	2	3	3	10	11	14	15	16	17
Expected Unserved Energy at 50th percentile demand	-	-	-	-	-	-	-	-	-	-	-
Expected Unserved Energy at 10th percentile demand	-	0.0	0.2	0.2	0.6	0.8	1.4	1.6	2.2	2.3	
Expected Unserved Energy value at 50th percentile	\$ - M	\$ - M	\$ - M	\$ - M	\$ - M	\$ - M	\$ - M	\$ - M	\$ - M	\$ - M	\$ - M
Expected Unserved Energy value at 10th percentile	\$ - M	\$ 0.0 M	\$ 0.1 M	\$ 0.1 M	\$ 0.1 M	\$ 0.1 M					
weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value)	\$ - M	\$ 0.0 M									

Notes:

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

<sup>4</sup> Note that risk assessment for this station is carried out using station transformers' rating and loading.

**KEILOR TERMINAL STATION (KTS(B3,4) TRANSFORMER GROUP)<sup>5</sup>**

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

Distribution Businesses supplied by this station:

Jemena EN (45%), Powercor (55%) (following transfer of load to Deer Park Terminal Station)

Normal cyclic rating with all plant in service:

321 MVA at 50<sup>th</sup> percentile temperature and 311 MVA at 10<sup>th</sup> percentile temperature (Summer peaking)

Summer N-1 Station Transformer Rating:

321 MVA at 50<sup>th</sup> percentile temperature and 311 MVA at 10<sup>th</sup> percentile temperature [See Note 1 below for interpretation of N-1]

Winter N-1 Station Transformer Rating:

344 MVA

Station: KTS (B34)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50 <sup>th</sup> percentile Summer Maximum Demand (MVA)	287.3	223.5	227.4	231.9	235.9	240.9	245.3	248.2	252.2	254.6	257.5
50 <sup>th</sup> percentile Winter Maximum Demand (MVA)	165.8	167.4	170.1	174.2	178.1	182.5	185.6	188.2	190.9	193.6	196.8
10 <sup>th</sup> percentile Summer Maximum Demand (MVA)	287.3	254.2	259.6	259.9	264.7	269.8	271.3	277.1	280.5	284.1	288.1
10 <sup>th</sup> percentile Winter Maximum Demand (MVA)	175.8	177.7	181.0	185.3	188.2	192.7	196.5	199.0	201.9	205.0	207.3
N-1 energy at risk at 50th percentile demand (MWh)	-	-	-	-	-	-	-	-	-	-	-
N-1 hours at risk at 50th percentile demand (hours)	-	-	-	-	-	-	-	-	-	-	-
N-1 energy at risk at 10th percentile demand (MWh)	-	-	-	-	-	-	-	-	-	-	-
N-1 hours at risk at 10th percentile demand (hours)	-	-	-	-	-	-	-	-	-	-	-
Expected Unserved Energy at 50th percentile demand (MWh)	-	-	-	-	-	-	-	-	-	-	-
Expected Unserved Energy at 10th percentile demand (MWh)	-	-	-	-	-	-	-	-	-	-	-
Expected Unserved Energy value at 50th percentile demand	\$ - M										
Expected Unserved Energy value at 10th percentile demand	\$ - M										
Expected Annual Unserved Energy value (using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value)	\$ - M										

Notes:

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

<sup>5</sup> Note that risk assessment for this station is carried out using station transformers' rating and loading.

## KERANG TERMINAL STATION (KGTS) 66kV & 22kV

Kerang Terminal Station (KGTS) 66 kV and 22 kV consists of three 35 MVA 235/66/22 kV transformers and is the main source of supply for over 18,179 customers in Kerang and the surrounding area. The station supply area includes Kerang, Swan Hill and Cohuna.

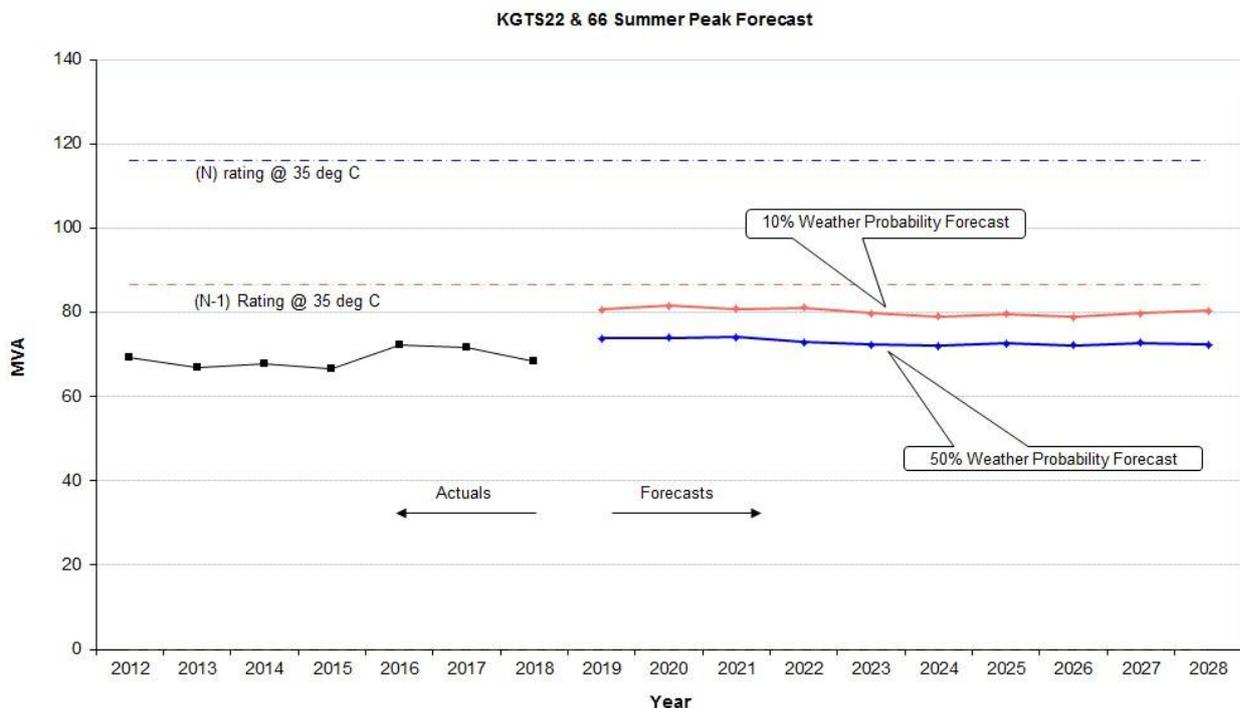
### Magnitude, probability and impact of loss of load

Growth in summer peak demand at KGTS has averaged around 0.28 MVA (0.5%) per annum over the last 5 years. The peak load on the station reached 67.6 MW (66 kV and 22 kV networks) in summer 2018.

It is estimated that:

- For 10 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at the time of peak demand is 0.97.

KGTS 22 & 66 kV demand is summer peaking. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> 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 above graph shows that there is sufficient capacity at the station to supply all expected demand at the 50<sup>th</sup> and 10<sup>th</sup> percentile temperatures over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

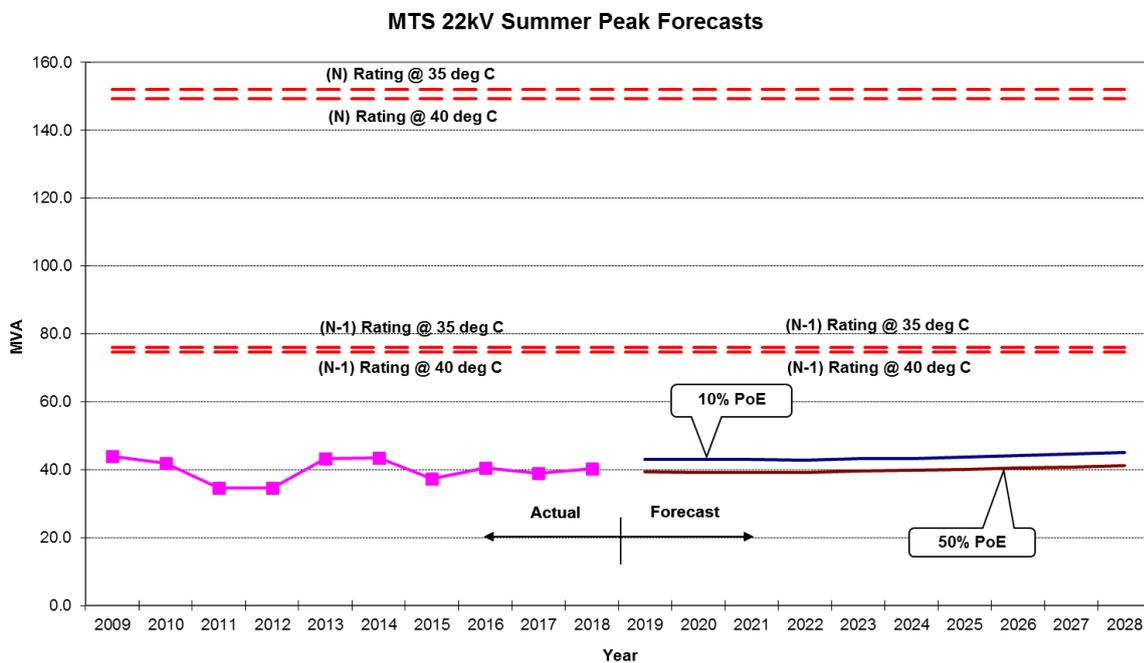
## MALVERN 22 kV TERMINAL STATION (MTS 22 kV)

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

MTS 22 kV is a summer critical terminal station. The recorded demand in summer 2018 was 39.6 MW (43.0 MVA), which was approximately 4.2 MW higher than the summer 2017 peak. There are no embedded generation units over 1 MW connected at MTS 22 kV.

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

In addition to historical summer maximum demands, the graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station’s operational N rating (all transformers in service) and the (N-1) rating at 35°C as well as 40°C ambient temperature.



The N rating on the graph indicates the maximum load that can be supplied from MTS 22 kV with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

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

The station load is forecast to have a power factor of 0.984 at times of peak demand. The demand at MTS 22 kV is expected to exceed 95% of peak demand for approximately 5 hours per annum. There is approximately 4 MVA of load transfer available at MTS 22 kV for summer 2018/19.

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

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

## MALVERN TERMINAL STATION 22 kV

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

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

Station: MTS 22kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	39.4	39.2	39.1	39.2	39.7	39.9	40.0	40.4	40.7	41.1
50th percentile Winter Maximum Demand (MVA)	31.7	31.7	31.6	31.5	31.5	31.5	31.6	31.6	31.7	31.7
10th percentile Summer Maximum Demand (MVA)	43.0	43.1	43.0	42.9	43.2	43.3	43.8	44.3	44.7	45.1
10th percentile Winter Maximum Demand (MVA)	31.7	31.7	31.6	31.5	31.5	31.5	31.6	31.6	31.7	31.7
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	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									
Expected Unserved Energy value at 10th percentile demand	\$0.0k									
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$0.0k									

#### Notes:

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

## MALVERN 66 kV TERMINAL STATION (MTS 66 kV)

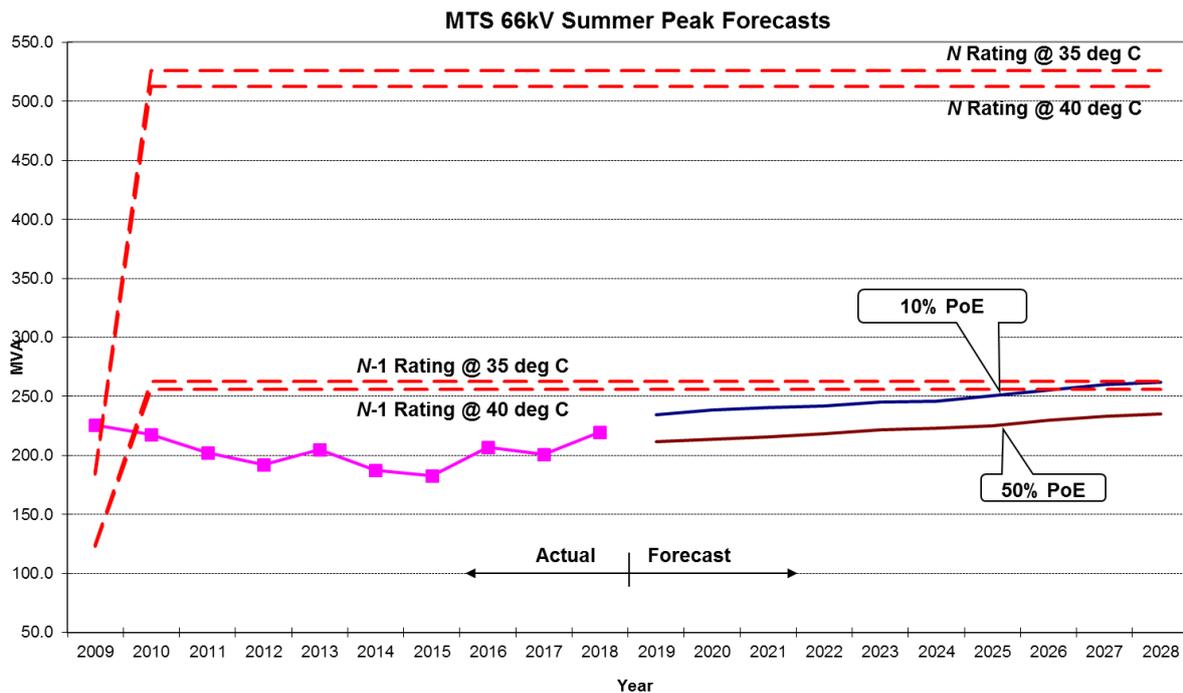
MTS 66 kV is the main source of supply for over 80,000 customers in Elsternwick, Caulfield, Carnegie, Malvern East, Ashburton, Chadstone, Oakleigh, Ormond, Murrumbeena, Hughesdale and Bentleigh East.

MTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 220 MW (226 MVA) in summer 2009. The recorded demand in summer 2018 was 215.6 MW (219.6 MVA), which was approximately 98% of the recorded historic maximum demand. 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).

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

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

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



The N rating on the graph indicates the maximum load that can be supplied from MTS 66 kV with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that the 10<sup>th</sup> percentile maximum demand is not expected to exceed the (N-1) rating until summer 2027 and the 50<sup>th</sup> percentile maximum demand is not expected to exceed the (N-1) rating in the 10 year forecast period.

The station load is forecast to have a power factor of 0.982 at times of peak demand. The demand at MTS 66 kV is expected to exceed 95% of the peak demand for approximately 4 hours per annum. There is approximately 17 MVA of load transfer available at MTS 66 kV for summer 2018/19.

On the basis of the latest forecasts, and given the minimal amount of load at risk over the next 10 years, the need for augmentation of transmission connection assets at MTS 66 kV is not expected to arise over the next decade.

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

## MALVERN TERMINAL STATION 66 kV

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

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

Station: MTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	212	214	216	218	221	223	225	230	233	235
50th percentile Winter Maximum Demand (MVA)	157	159	160	159	160	161	163	164	165	167
10th percentile Summer Maximum Demand (MVA)	235	239	241	242	245	246	251	255	260	262
10th percentile Winter Maximum Demand (MVA)	159	162	162	162	163	164	166	167	169	170
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	2	4
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
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									
Expected Unserved Energy value at 10th percentile demand	\$0.0k	\$0.3k	\$0.6k							
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$0.0k	\$0.1k	\$0.2k							

#### Notes:

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

## MT BEAUTY TERMINAL STATION 66 kV (MBTS 66 kV)

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

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

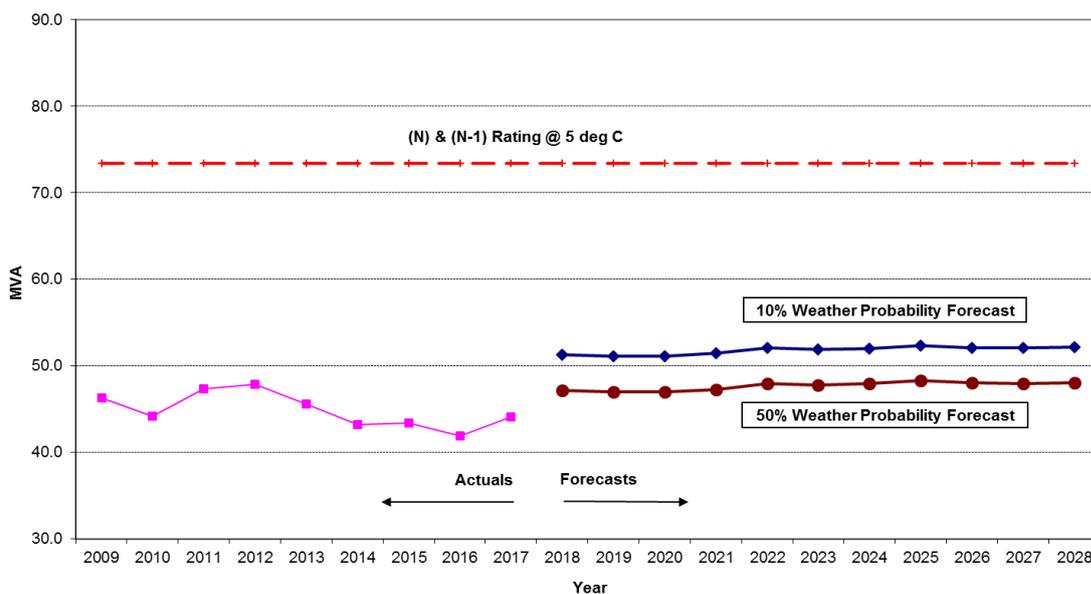
It is AusNet Electricity Services’ responsibility to plan the electricity supply network for this region.

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

MBTS is a winter peaking station with the peak demand on the MBTS 66 kV bus forecast to remain relatively flat for the next 10 years. Peak demand at the station reached 47.9 MVA in winter 2012. The recorded peak demand in winter 2017 was 44.1 MVA, which was lower than the 2012 peak demand due to relatively mild weather conditions experienced in winter 2017. The station load has a power factor of 0.998 at maximum demand. The demand at MBTS 66 kV is expected to exceed 95% of the 50<sup>th</sup> percentile peak demand for approximately 4 hours per annum. The summer peak demand is marginally lower than the winter peak demand.

The graph below depicts the 10th and 50th percentile winter maximum demand forecast together with the station’s operational “N-1” rating (equal to “N” rating) at an ambient temperature of 5°C. With the forecast growth rates, MBTS 66 kV is not expected to reach its “N-1” winter station rating during the 10 year planning horizon.

MBTS 66 kV Winter Peak Demand Forecasts



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<sup>1</sup> in this situation (taking account of the limited 66 kV tie line capability) is significant at around 4,866 MWh in winter 2018 and increasing to 5,507 MWh by 2028. However, given that the hot spare transformer can be made available within 4 hours, the expected outage duration in the case of a major transformer failure at MBTS is 4 hours (rather than 2.6 months). Accordingly, the probability of the transformer being unavailable in this particular case is only 0.000457%. The expected unserved energy at MBTS is therefore approximately 0.025 MWh in 2028 and this is estimated to have a value to consumers of approximately \$1,062 (based on a value of customer reliability of \$42,198/MWh).

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

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<sup>1</sup> In this report, "major transformer outage" means an outage that has a mean duration of 2.6 months.

## MORWELL TERMINAL STATION 66 kV (MWTS 66 kV)

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

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

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

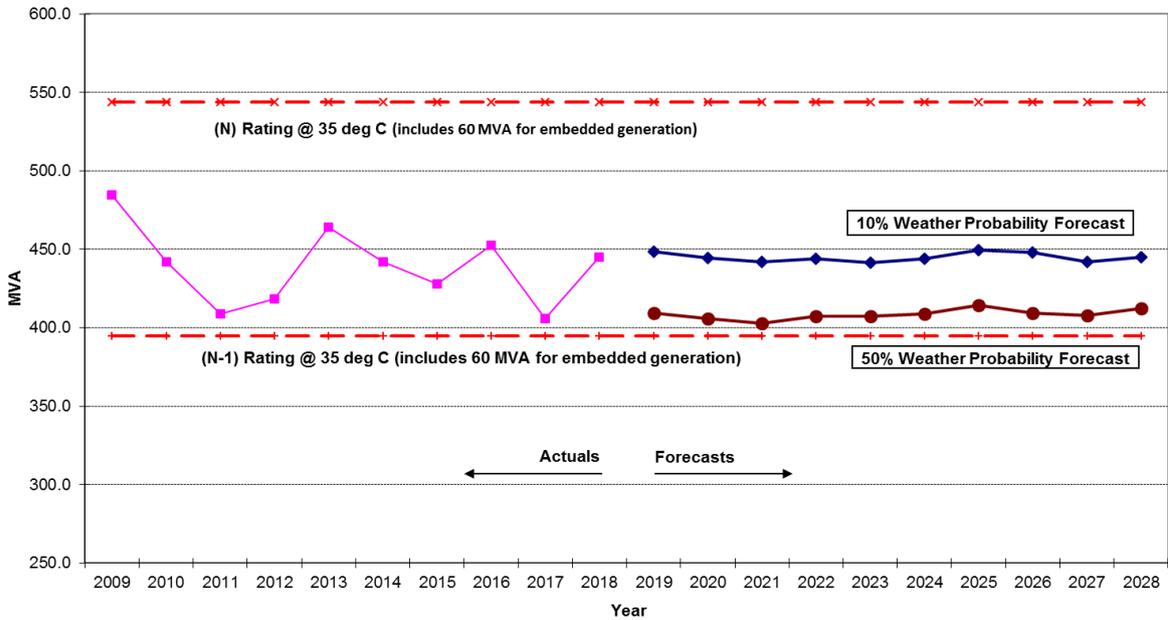
MWTS 66 kV is supplied by two 150 MVA 220/66 kV transformers and one 165 MVA 220/66 kV transformer.

MWTS 66 kV is a summer peaking station and recorded a maximum demand of 452 MW (464 MVA) in early January 2013. The peak demand on the station reached 441.3 MW (445.1 MVA) in summer 2017/18. The peak demand period is usually quite short, and coincides with a few weeks of peak tourism from Christmas to early January along the east coast of Victoria. The maximum demand recorded is very dependent on weather conditions during this short period. The load at MWTS 66 kV is forecast to remain relatively flat for the ten year planning horizon. The station load has a power factor of 0.99 at maximum demand. MWTS 66 kV demand is expected to exceed 95% of the 50<sup>th</sup> percentile peak demand for 5 hours per annum.

The assessment of the energy at risk at MWTS 66 kV needs to take into account the significant levels of embedded generation 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, in order to make a realistic assessment of the risk at MWTS the total output from these embedded generators is assumed to be 60 MVA.

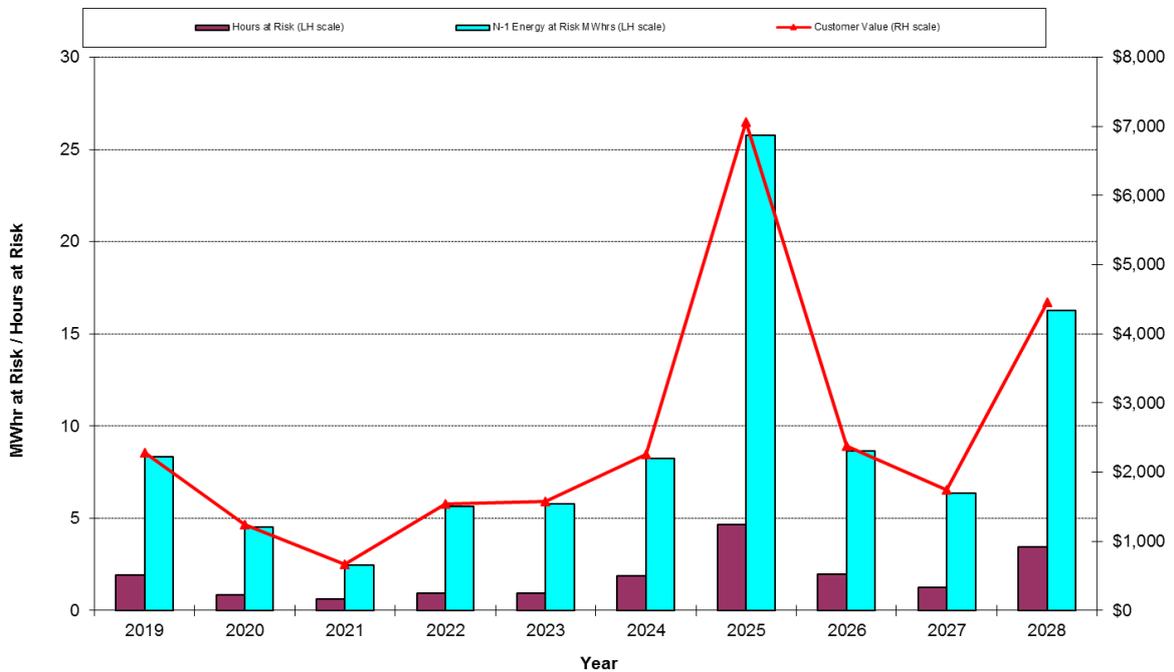
The “N-1” and “N” ratings shown on the graph below include the transformer capacity as well as the assumed 60 MVA contribution from embedded generation. For example the 395 MVA “N-1” rating includes the 335 MVA capacity of two 220/66 kV transformers and 60 MVA from embedded generation. The graph also shows the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station’s operational “N” rating (all transformers in service plus 60 MVA from embedded generation) and the “N-1” rating at an ambient temperature of 35°C. The “N” rating on the chart indicates the maximum load that can be supplied from MWTS 66 kV with all transformers in service. Summer peak demand loading at MWTS is expected to exceed the station’s “N-1” rating for the entire 10 year planning period.

MWTS 66 kV Summer Peak Demand Forecasts including generation



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

Annual Energy and Hours at Risk at MWTS 66 (Single Contingency Only)



MWTS is not expected to be loaded above its “N-1” rating under 50<sup>th</sup> percentile or 10<sup>th</sup> percentile winter maximum demand forecasts during the 10 year planning horizon.

## Comments on Energy at Risk

As noted above, embedded generation is assumed to be contributing 60 MVA during the peak demand period, which represents approximately 25 percent of the total installed capacity of the embedded generators in the MWTS 66 kV network.

For an outage of one MWTS 220/66 kV transformer over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for approximately 1.9 hours in 2018/19. The corresponding energy at risk under “N-1” conditions is estimated to be approximately 8 MWh. The estimated value to consumers of this energy at risk is approximately \$0.34 million (based on a value of customer reliability of \$42,199/MWh)<sup>1</sup>. It is noted, however, that the probability of a major outage of one of the three transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk is weighted by this low unavailability, the expected unsupplied energy is 0.05 MWh with a value of \$2,200.

Under higher summer temperature conditions (that is at the 10<sup>th</sup> percentile level), the energy at risk in 2018/19 is estimated to be 378 MWh. The estimated value to consumers of the energy at risk is \$16 million. When this energy at risk is weighted by the transformer unavailability, the expected unserved energy is estimated to be 2.5 MWh, which has a value to consumers of around \$0.10 million.

These key statistics for the year 2018/19 under “N-1” outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	8	\$0.34 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	0.05	\$2,200
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	378	\$16 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	2.5	\$0.10 million

If one of the 220/66 kV transformers at MWTS is taken off line during peak loading times and the “N-1” station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is operated by AusNet Transmission Group’s TOC<sup>2</sup> to protect the connection assets from overloading<sup>3</sup>, 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.

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

<sup>2</sup> Transmission Operation Centre.

<sup>3</sup> 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.

## Feasible options for alleviation of constraints

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

1. Embedded generation: Bairnsdale Power Station is contracted to provide 20 MW over the night time hot water demand peak and during the afternoon peak demand period but it has the capacity to provide up to 80 MW if needed.
2. Subject to the availability of the AusNet Transmission Services' spare 220/66 kV transformer for rural areas (refer section 5.5), this spare transformer can be used to temporarily replace a failed transformer.
3. Install a fourth 220/66 kV transformer at MWTS: Installation of a 4<sup>th</sup> 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 further improve the power factor and to reduce the MVA loading on the transformers will provide only marginal benefits.
5. Load transfers: Only 5 MVA of load can be shifted away from MWTS using the existing 22 kV distribution network, so this option does not make a material contribution to managing the risk at MWTS.

## Preferred network option for alleviation of constraints

In view of the current level of expected unserved energy at MWTS, and the relatively flat forecast demand over the next 10 years, implementing a network solution is unlikely to be economic 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: Magnitude and probability of loss of load

Distribution Businesses supplied by this station:

AusNet Electricity Services (100%)

Normal cyclic rating with all plant in service

544 MVA via 3 transformers and embedded generation

Summer N-1 Station Rating

395 MVA via 2 transformers and embedded generation

Winter N-1 Station Rating

474 MVA via 2 transformers and embedded generation

Station: MWTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	409.1	405.8	402.9	407.1	407.2	409.0	414.5	409.2	407.8	412.1
50th percentile Winter Maximum Demand (MVA)	349.6	352.0	356.9	364.3	364.8	368.2	372.8	372.5	373.6	376.6
10th percentile Summer Maximum Demand (MVA)	448.6	444.5	441.7	444.0	441.3	443.8	449.7	447.9	442.2	445.1
10th percentile Winter Maximum Demand (MVA)	356.1	358.3	363.0	369.8	371.0	373.4	377.8	377.3	378.7	381.4
N - 1 energy at risk at 50th percentile demand (MWh)	8	5	2	6	6	8	26	9	6	16
N - 1 hours at risk at 50th percentile demand (hours)	1.9	0.8	0.6	0.9	0.9	1.9	4.7	2.0	1.2	3.4
N - 1 energy at risk at 10th percentile demand (MWh)	378	319	280	311	274	309	395	368	286	327
N - 1 hours at risk at 10th percentile demand (hours)	16.3	15.2	14.5	15.1	14.4	15.0	16.6	16.1	14.6	15.4
N and N-1 Expected Unserved Energy at 50th percentile demand (MWh)	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.0	0.1
N and N-1 Expected Unserved Energy at 10th percentile demand (MWh)	2.5	2.1	1.8	2.0	1.8	2.0	2.6	2.4	1.9	2.1
N and N-1 Expected Unserved Energy value at 50th percentile demand	\$0.00M	\$0.00M	\$0.00M	\$0.00M	\$0.00M	\$0.00M	\$0.01M	\$0.00M	\$0.00M	\$0.00M
N and N-1 Expected Unserved Energy value at 10th percentile demand	\$0.10M	\$0.09M	\$0.08M	\$0.09M	\$0.08M	\$0.08M	\$0.11M	\$0.10M	\$0.08M	\$0.09M
N and N-1 Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$0.03M	\$0.03M	\$0.02M	\$0.03M	\$0.02M	\$0.03M	\$0.04M	\$0.03M	\$0.02M	\$0.03M

Notes:

- "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.
- "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.
- "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.
- "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
- The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
- The 0.7 and 0.3 weightings applied to the 50<sup>th</sup> and 10<sup>th</sup> percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))

## RED CLIFFS TERMINAL STATION (RCTS) 22kV

Red Cliffs Terminal Station (RCTS) 22 kV consists of two 35 MVA 235/66/22 kV transformers supplying the 22 kV network ex-RCTS. An additional 140 MVA 235/66/22 kV transformer operates normally open on the 22 kV bus with an auto-close scheme to close this transformer onto the 22 kV bus in the event of a failure of either of the other two transformers. This configuration is the main source of supply for 6,367 customers in Red Cliffs and the surrounding area. The station supply area includes Red Cliffs, Colignan and Werrimull.

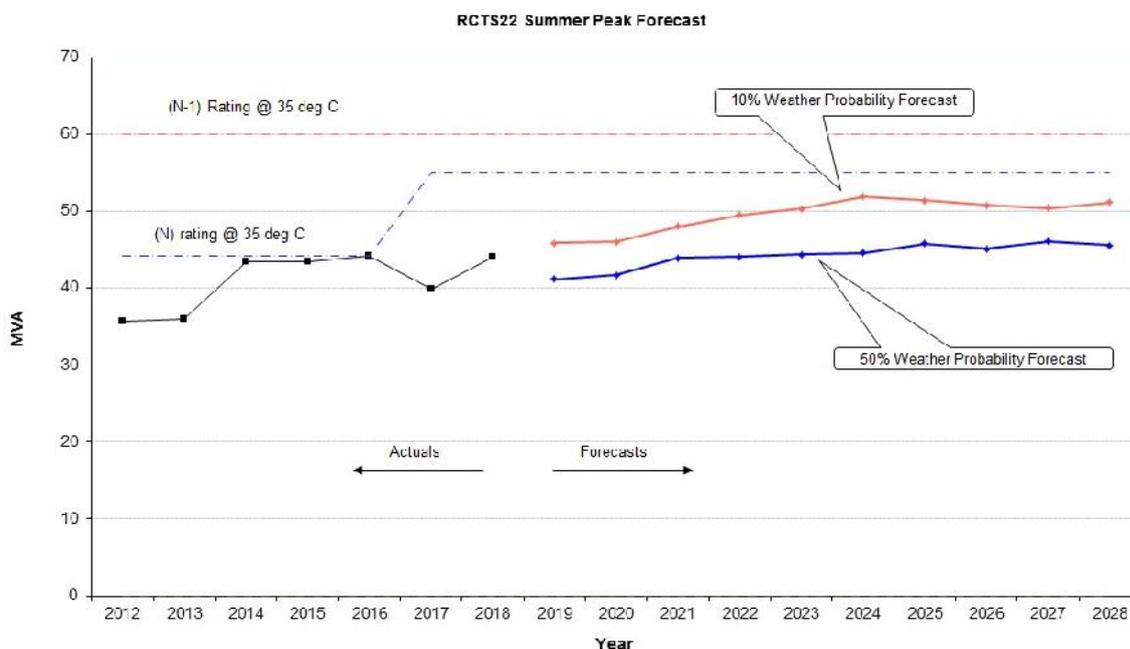
### Magnitude, probability and impact of loss of load

The peak load for the RCTS 22 kV network reached 41.3 MW in summer 2018. It is estimated that:

- For 7 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station transformer power factor at the peak time demand is 0.94 with both capacitor banks in service.

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 demand is summer peaking. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station’s operational “N” rating and the “N-1” rating at 35°C ambient temperature. The RTS 22 kV station N rating was increased to 55 MVA following the uprating of the 22 kV droppers by AusNet Transmission Group in 2016.



The graph shows there is sufficient capacity at the station to supply all expected load at the 50<sup>th</sup> and 10<sup>th</sup> percentile temperatures over the forecast period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

## 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 22,035 customers in Red Cliffs and the surrounding area. The station supply area includes Merbein, Mildura and Boundary Bend.

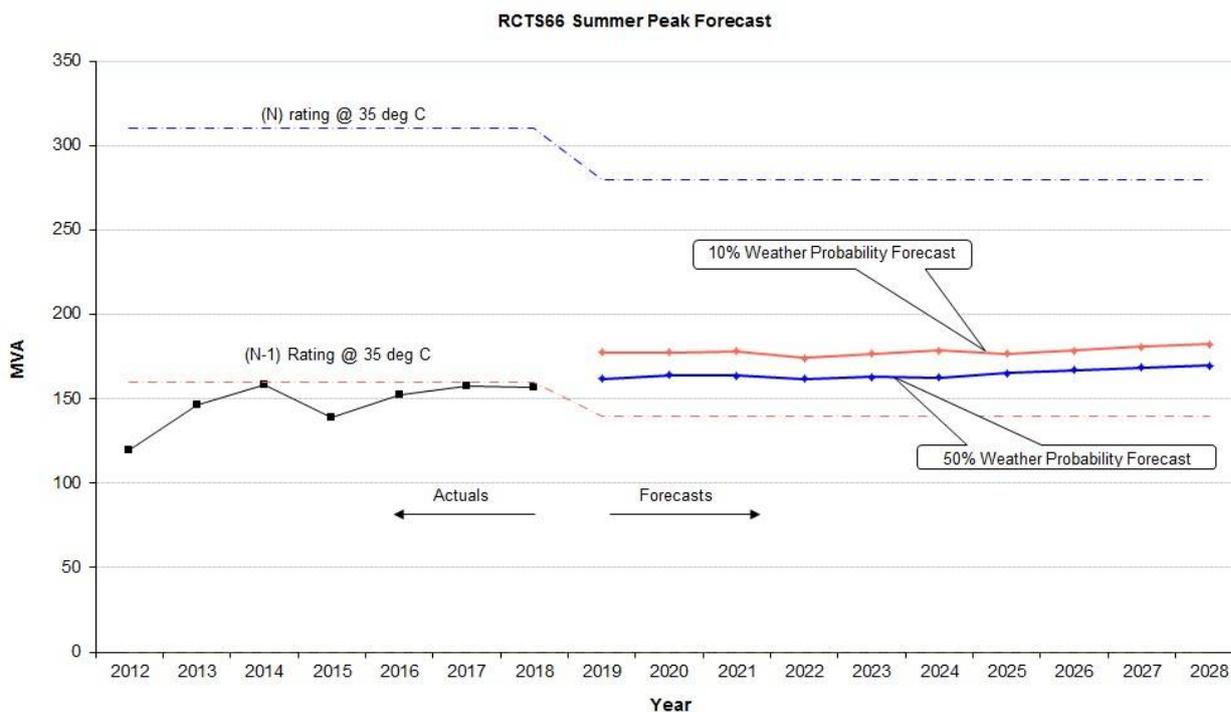
### Magnitude, probability and impact of loss of load

RCTS 66 kV demand is summer peaking. In February 2012, part of the 66 kV network previously supplied from RCTS was transferred to the new Wemen Terminal Station (WETS). This is reflected in the reduction in actual demand in that year (shown in the chart below). The peak load for the 66 kV network now supplied from the station reached 146.9 MW in summer 2018. As noted in section 3.2.1 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 advance of AusNet Transmission Services completing its review of ratings at stations affected by reverse power flows, this risk assessment adopts the conservative assumption that from 2019 the station rating of RCTS 66 kV is reduced from cyclic to nameplate. This reduction is shown in the graph below.

It is estimated that:

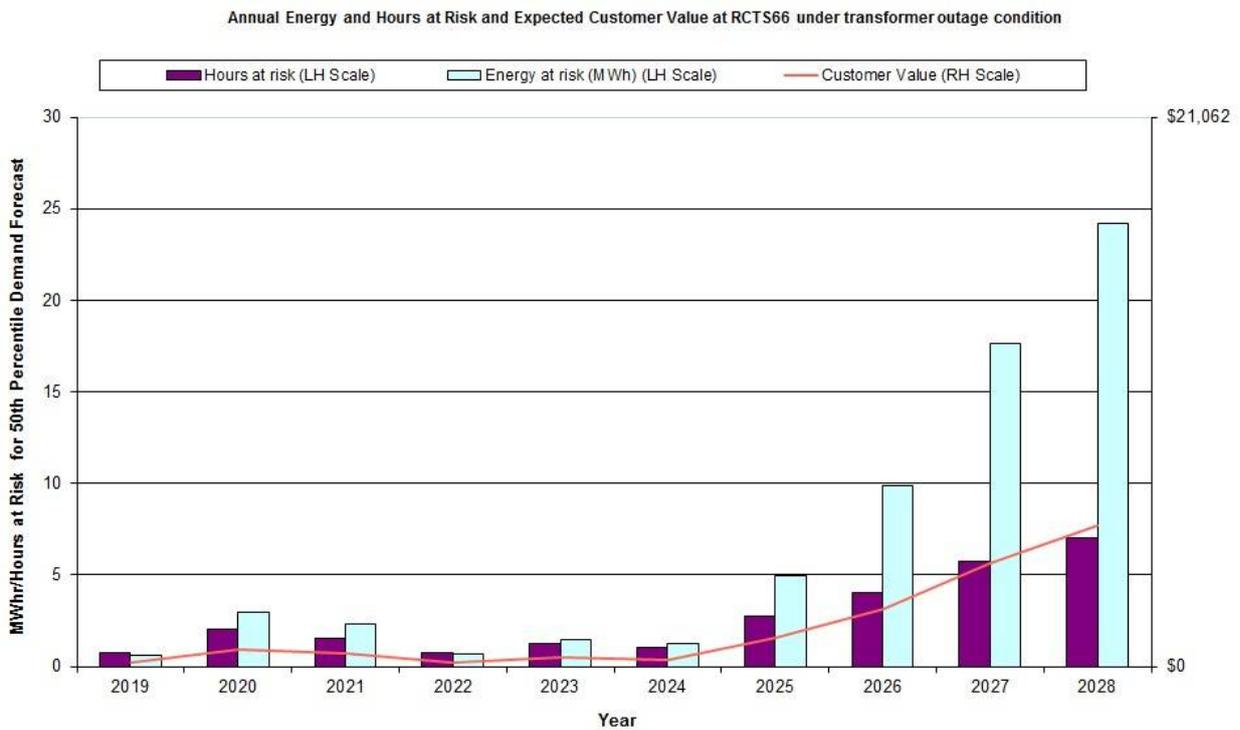
- For 13 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at the time of peak demand 0.94.

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



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

The bar chart below depicts the energy at risk with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours per year that the 50<sup>th</sup> 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 50<sup>th</sup> percentile demand forecast.



### Comments on Energy at Risk

For a major outage of one transformer at RCTS 66 kV during the summer period, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 7 hours in 2028. The energy at risk at the 50<sup>th</sup> percentile temperature under N-1 conditions is estimated to be 24.2 MWh in 2028. The estimated value to consumers of the 24.2 MWh of energy at risk is approximately \$0.8 million (based on a value of customer reliability of \$34,349/MWh).<sup>1</sup> In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at RCTS 66 kV in 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers approximately \$0.8 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (24.2 MWh for 2028) is weighted by this low unavailability, the expected unsupplied energy is estimated to be around 0.16 MWh. This expected unserved energy is estimated to

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

have a value to consumers of around \$5,500 (based on a value of customer reliability of \$34,349/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2028 is estimated to be 257.6 MWh. The estimated value to consumers of this energy at risk in 2019 is approximately \$8.8 million. The corresponding value of the expected unserved energy (of 1.67 MWh) is approximately \$57,500.

These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	24.2	\$0.8 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	0.16	\$5,500
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	257.6	\$8.8 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	1.67	\$57,500

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

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

### **Feasible options for alleviation of constraints**

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

1. Embedded generation: Three new solar farms (Bannerton Solar Park (BSP), Wemen Sun Farm (WSF) and Karadoc Solar Farm (KSF)) are scheduled to be commissioned in 2019 and will generate into the 66 kV infrastructure with a total capacity of 265.8 MW. BSP (88 MW), WSF (87.8 MW) and KSF (90 MW) will be able to help supply the loads at RVL ZSS and BBD ZSS, which will reduce the loads at RCTS 66kV, and may defer the need for any capacity augmentation within the forecast period.
2. Possible uptake of battery storage in the future could provide some contribution to supporting the peak load.

<sup>2</sup> Overload Shedding Scheme of Connection Asset.

<sup>3</sup> Transmission Operation Centre.

3. A contingency plan to transfer RVL and OYN zone substations from RCTS to WETS (~42 MVA) will be implemented in the event of the loss of one of the RCTS 220/66 kV transformers.
4. Subject to the availability of an AusNet Transmission Group spare 220/66 kV transformer for rural areas (refer to Section 5.5), a spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

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

As already noted, a contingency plan to transfer RVL and OYN zone substation from RCTS to WETS (~42 MVA) will be implemented in the event of the loss of one of the RCTS 220/66 kV transformers. In addition, generation output from the new solar farms BSP, WSF and KSF may help supply the loads at RVL and BBD if required.

The level of expected unserved energy over the forecast period suggests that installation of additional capacity at RCTS 66 kV is unlikely to be economically justified during the forecast period. The contingency plan described above will provide an effective means of mitigating load at risk 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.

## Red Cliffs Terminal Station

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

**Distribution Businesses supplied by this station:** Powercor (100%)  
**Normal cyclic rating with all plant in service** 310 MVA via 2 transformers (Summer peaking)  
**Summer N-1 Station Rating:** 160 MVA [See Note 1 below for interpretation of N-1]  
**Winter N-1 Station Rating:** 192 MVA

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	161.9	164.0	163.6	162.0	162.9	162.7	165.1	166.8	168.5	169.6
50th percentile Winter Maximum Demand (MVA)	89.5	90.7	92.0	92.4	93.7	95.0	95.7	96.4	97.2	98.5
10th percentile Summer Maximum Demand (MVA)	177.6	177.3	178.1	173.9	176.7	178.4	176.8	178.6	180.9	182.2
10th percentile Winter Maximum Demand (MVA)	99.8	99.7	101.7	102.9	103.3	104.8	105.2	106.2	107.1	108.0
N-1 energy at risk at 50% percentile demand (MWh)	0.6	2.9	2.3	0.7	1.5	1.2	4.9	9.9	17.6	24.2
N-1 hours at risk at 50th percentile demand (hours)	0.8	2.0	1.5	0.8	1.3	1.0	2.8	4.0	5.8	7.0
N-1 energy at risk at 10% percentile demand (MWh)	132.9	127.0	143.7	67.8	114.6	149.9	117.0	156.3	218.2	257.6
N-1 hours at risk at 10th percentile demand (hours)	21.0	20.5	21.8	14.0	19.3	22.5	19.5	23.0	29.0	32.3
Expected Unserved Energy at 50th percentile demand (MWh)	0.00	0.02	0.01	0.00	0.01	0.01	0.03	0.06	0.11	0.157
Expected Unserved Energy at 10th percentile demand (MWh)	0.86	0.83	0.93	0.44	0.74	0.97	0.76	1.02	1.42	1.67
Expected Unserved Energy value at 50th percentile demand	\$0.00M	\$0.01M								
Expected Unserved Energy value at 10th percentile demand	\$0.03M	\$0.03M	\$0.03M	\$0.02M	\$0.03M	\$0.03M	\$0.03M	\$0.03M	\$0.05M	\$0.15M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$0.01M	\$0.01M	\$0.01M	\$0.00M	\$0.01M	\$0.01M	\$0.01M	\$0.01M	\$0.02M	\$0.02M

#### Notes:

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

## RICHMOND TERMINAL STATION 22 kV (RTS 22 kV)

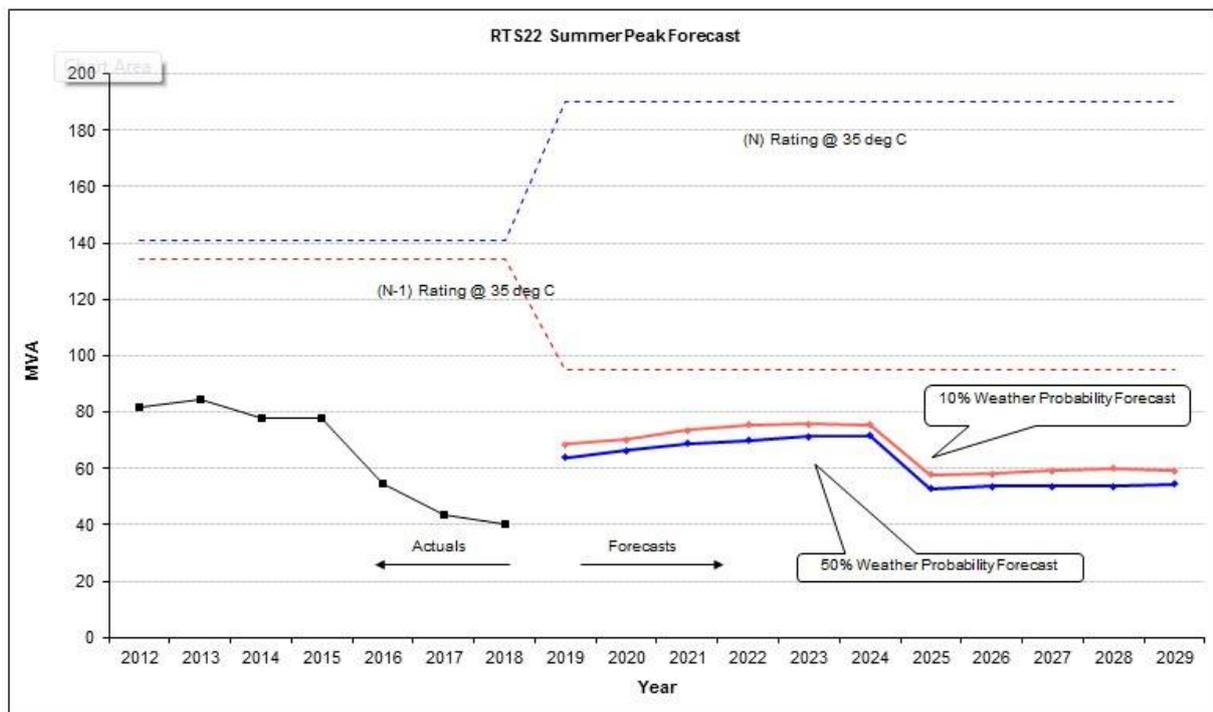
RTS 22 kV is a summer critical station equipped with two 75 MVA 220/22 kV transformers, providing supply to 7,087 customers in CitiPower’s distribution network. The terminal station’s supply area includes inner suburban areas in Richmond and Melbourne City’s Russell Place and surrounding areas. The station also provides supply to City Link and public transport railway substations east of the Central Business District.

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 rating have subsequently changed to approximately 190 MVA and 95 MVA respectively. This is reflected in the graph below.

The peak load on the station reached 4 39.2 MW in summer 2018. It is estimated that:

- For 9 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile forecast.
- The station load power factor at time of peak demand is 0.98.

The graph below depicts the latest 10% and 50% probability maximum demand forecasts during the summer periods over the next ten years, together with the operational N and N-1 ratings for RTS 22 kV. The demand forecasts include the effects of future load transfer works that have been committed. RTS 22 kV load reductions (approximately 25 MVA) in 2014 and 2015 were due to load transfers to RTS 66 kV as part of the Prahran (PR22) Zone Substation de-commissioning process.



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

## RICHMOND TERMINAL STATION 66 kV (RTS 66 kV)

RTS 66 kV is a summer critical station consisting of three 225 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (91%) and United Energy (9%), providing supply to a total of 155,628 customers in the Eastern Central Business District and widespread inner suburban areas in the east and south-east of Melbourne, including Fitzroy, Collingwood, Abbotsford, Richmond, North Richmond, Hawthorn, Camberwell, Gardiner, Toorak, Armadale, South Yarra, St Kilda, Elwood and Balaclava.

In 2018 AusNet Transmission Group completed an asset replacement project at RTS, which involved replacing the ageing five existing 150 MVA transformers with three 225 MVA transformers.

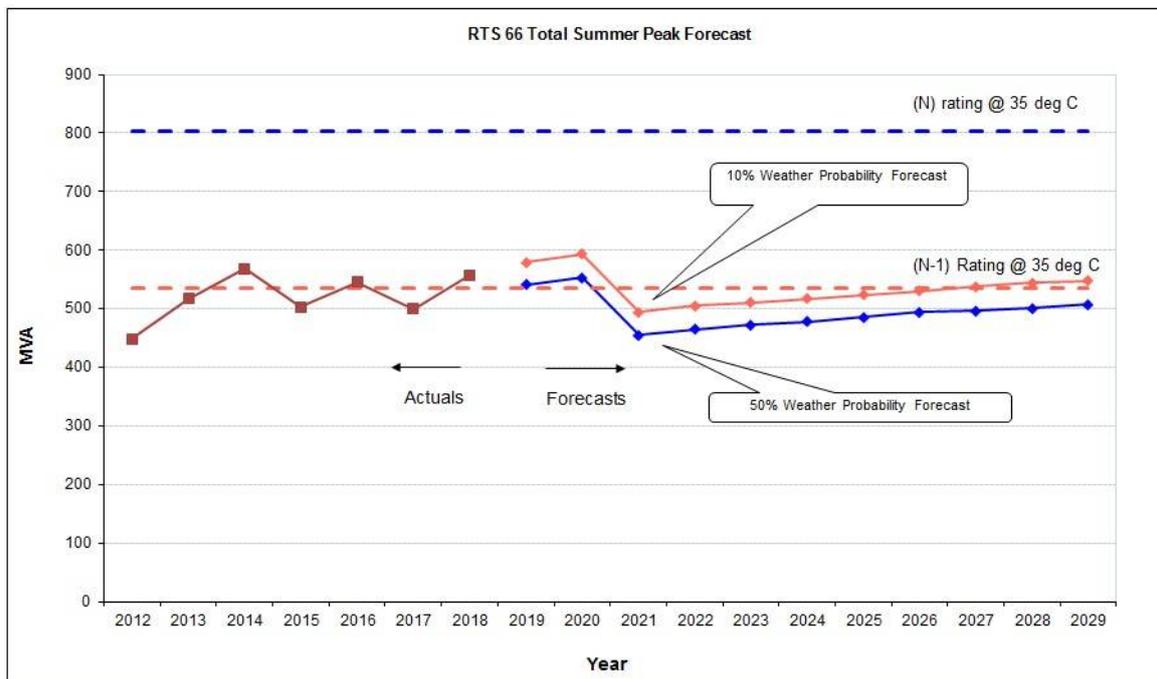
### Magnitude, probability and impact of loss of load

The peak load on the station reached 551.71 MW in summer 2018.

It is estimated that:

- For 11 hours per year, 95% of peak demand is expected to be reached in a 50<sup>th</sup> percentile summer.
- The station load power factor at time of peak demand is 0.99.

The following graph shows recent actual demand at the station, and the forecast demand from 2019 to 2029. The station’s (N) and (N-1) ratings at 35 degrees C are also shown.



The graph shows that there is some load at risk for the first two years of the forecast period. This will be managed through the use of a fourth temporary 150 MVA transformer. For the failure of one 225 MVA transformer, the bus will be split so that the 150 MVA transformer supplies EW and SK and the remaining two 225 MVA transformers supply the remaining load. After the 2020 summer, MP zone substation will be transferred to BTS and this removes the load at risk until 2028 when the 10<sup>th</sup> percentile demand forecast will reach the N-1 rating and at this point load transfers will be used to manage any load at risk. Therefore, the need for further augmentation of capacity at RTS 66 kV is not expected to arise over the next ten years.

## RINGWOOD TERMINAL STATION 22 kV (RWTS 22 kV)

Ringwood Terminal Station provides supply at two voltage levels - 66 kV and 22 kV. RWTS 22 kV is now supplied by two 75 MVA 220/22 kV three-phase transformers following completion of AusNet Transmission Group’s asset replacement project in 2013. RWTS 22 kV is the main source of 22 kV supply for the local area and for the commuter railway network.

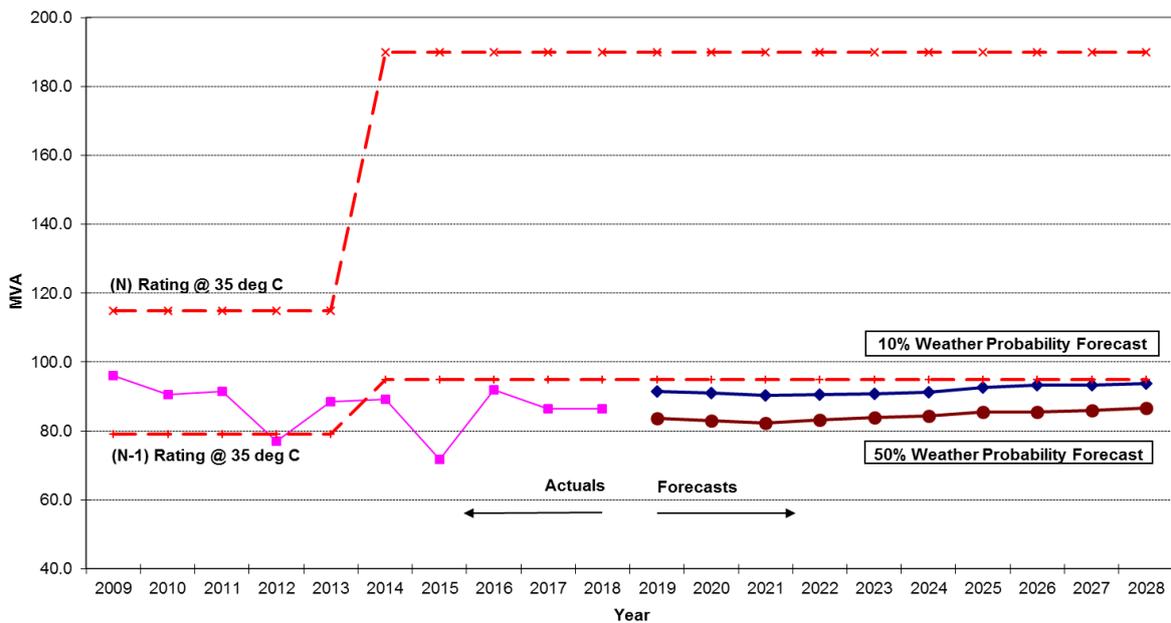
The geographic coverage of the station’s supply area includes Ringwood, Mitcham, Wantirna and Nunawading. The electricity distribution networks for this area are the responsibility of both AusNet Electricity Services (68%) and United Energy Distribution (32%).

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

Peak demand at the station occurs in summer. Summer peak demand at RWTS 22 kV is forecast to remain relatively flat over the ten year planning period. The station recorded a peak demand of 90.2 MW (92.0 MVA) in summer 2015/16 which is the highest recorded peak demand since the summer 2008/09 peak demand of 96.2 MVA. The peak demand in summer 2017/18 was 85.1 MW (86.4 MVA). Demand at RWTS 22 kV is expected to exceed 95% of the 50<sup>th</sup> percentile peak demand for 3 hours per annum. The station load has a power factor of 0.99 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.

RWTS 22 kV is not expected to be loaded above its “N-1” rating under 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecasts during the ten year planning horizon. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecasts together with the station’s “N-1” rating at an ambient temperature of 35°C.

RWTS 22 kV Summer Peak Demand Forecasts



As already noted, demand remains below the “N-1” rating under both 10<sup>th</sup> percentile and 50<sup>th</sup> percentile maximum demand forecasts for the ten year planning period between 2018/19 to 2027/28. There is therefore not expected to be any need for augmentation or other corrective action over the ten year planning period.

## RINGWOOD TERMINAL STATION 66 kV (RWTS 66 kV)

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

The electricity supply distribution networks for this region are the responsibility of both AusNet Electricity Services (77%) and United Energy (23%).

### 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, load demand on the RWTS bus groups 1-3 and 2-4 must be kept within the capabilities of their respective two transformers at all times otherwise load shedding may occur. For an unplanned transformer outage in any of the two RWTS bus groups, an auto close scheme will operate resulting in parallel operation of the three remaining transformers.

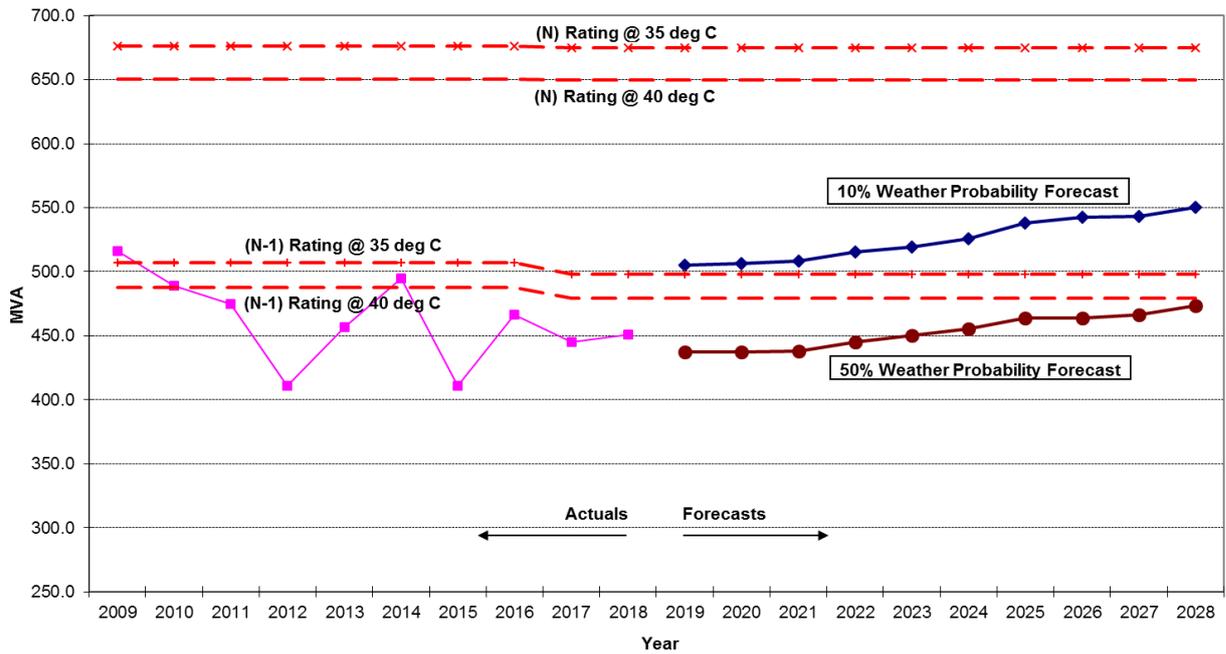
### Combined Summer Peak Demand forecasts for RWTS 66 kV - Total Station Demand

The peak demand on the station reached 494 MW (495 MVA) in summer 2013/14. The recorded peak demand in summer 2017/18 was 440.2 MW (451.1MVA), which was lower than the summer 2013/14 station peak demand. The station load has a power factor of 0.98 at maximum demand but the load on the transformers has a power factor of 1 due to installed 66 kV capacitor banks. RWTS 66 kV demand is expected to exceed 95<sup>th</sup> percentile peak demand for 7 hours per annum.

If one transformer is out of service ("N-1"), RWTS 66 kV is forecast to have load at risk of 1.3 MWh at the 10<sup>th</sup> percentile temperature in summer 2018/19, increasing steadily to 427 MWh by summer 2027/28. The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecasts together with the station's "N" and "N-1" ratings at ambient temperatures of 35°C and 40°C.

The combined winter demand at RWTS 66 kV is not expected to reach the station's "N-1" winter rating during the ten year planning horizon.

**Total Station Load: RWTS 66 kV Summer Peak Demand Forecasts**



**RWTS Bus groups 1-3 and 2-4: Summer Peak Demand Forecasts**

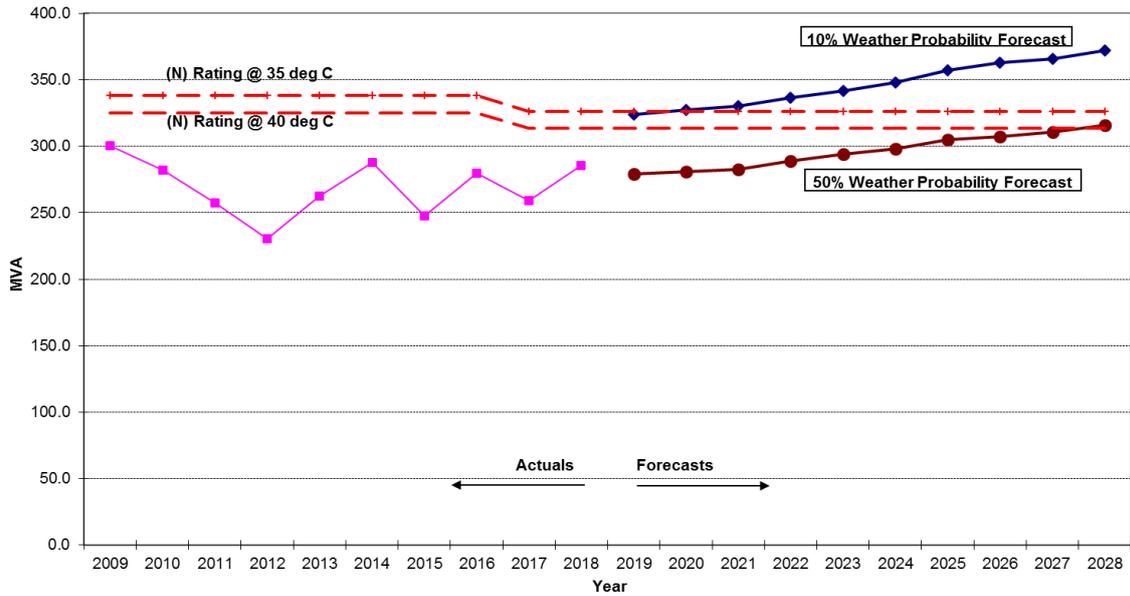
In addition to considering the station’s total summer demand under “N-1” conditions as shown above, it is essential to assess the risk of load shedding on the individual bus groups when both of their respective transformers are in service, i.e under “N” conditions.

**RWTS Bus group 1-3:** Peak demand at RWTS 66 kV bus group 1-3 occurs in summer. Based on the individual summer demand forecasts for this bus group, with both transformers in service, i.e. under “N” conditions, the demand on this bus group at the 50<sup>th</sup> percentile temperature is forecast to remain within its “N” rating. The 10<sup>th</sup> percentile summer maximum demand is however forecast to exceed the maximum 35 degree “N” rating from summer 2019/20. Where required, such as if a 10<sup>th</sup> percentile temperature day is anticipated, 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), Chrinside Park (CPK) and Woori Yallock (WYK).

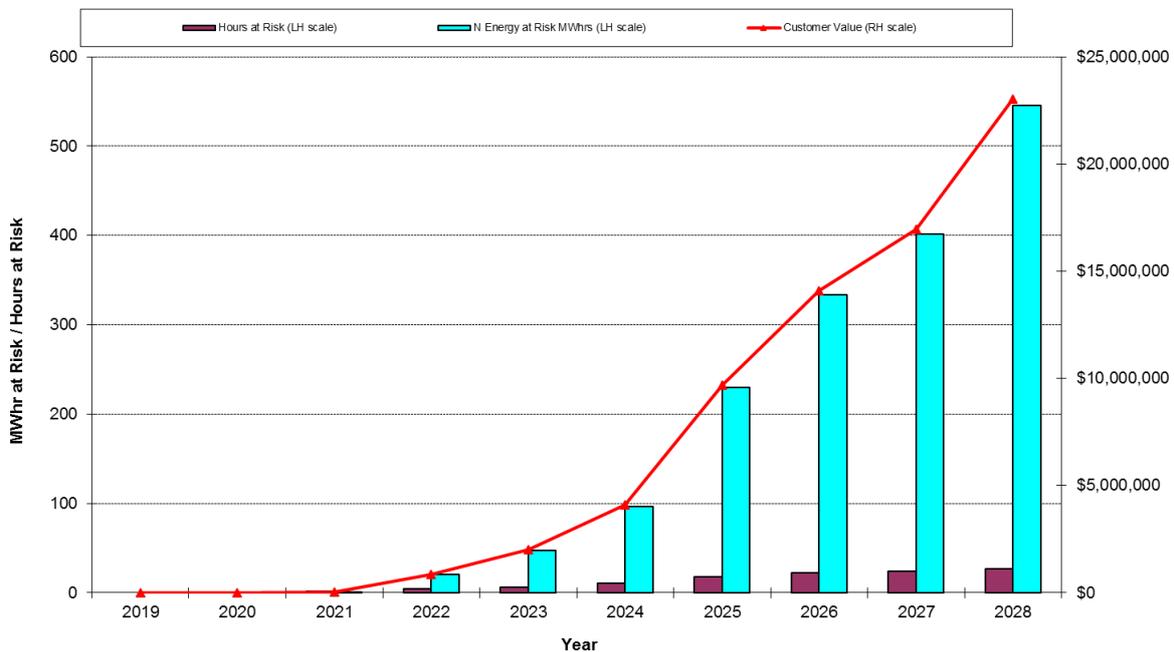
The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecasts together with the bus group 1-3 “N” rating at an ambient temperature of 35°C and 40°C.

Bus Group 1-3: RWTS 66 kV Summer Peak Demand Forecasts



The bar chart below depicts the “N” energy at risk for the 10<sup>th</sup> percentile demand forecast, and the hours per year that the 10<sup>th</sup> percentile demand forecast is expected to exceed the “N” capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 10<sup>th</sup> percentile demand forecast.

Annual Energy and Hours at Risk at RWTS13 66 kV (Bus group 1-3)

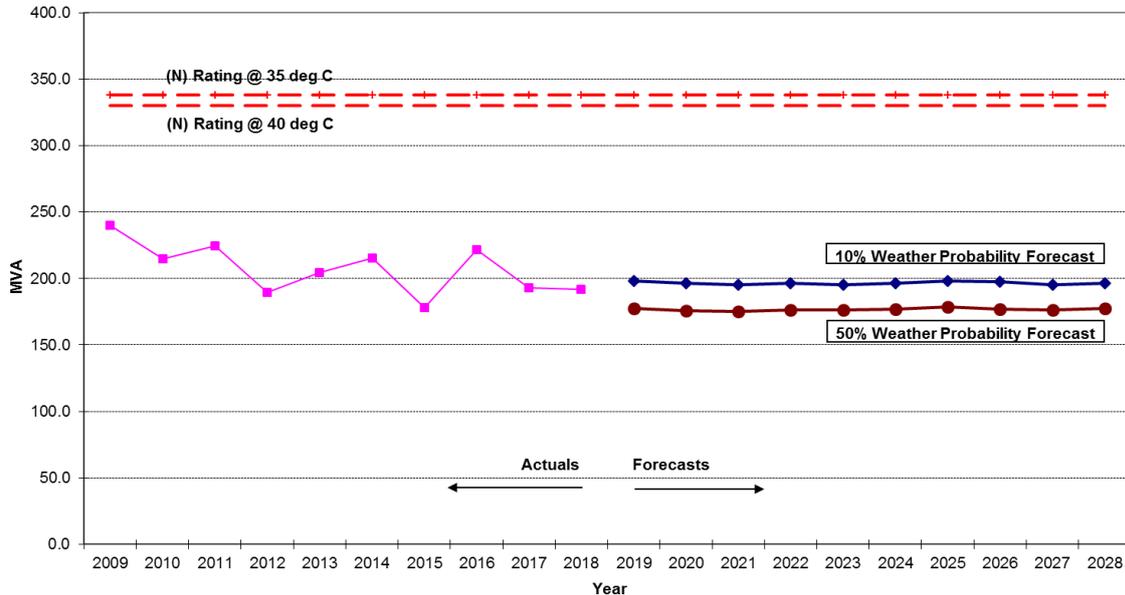


**RWTS Bus group 2-4:** Similar to bus group 1-3, the peak demand at RWTS 66 kV bus group 2-4 also occurs in summer. Based on the individual summer demand forecasts for this bus group, with both transformers in service, i.e. under “N” conditions, the demand on this bus group at the 50<sup>th</sup> or 10<sup>th</sup> 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 plant 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 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecasts together with the bus group 2-4 rating at an ambient temperature of 35°C and 40°C.

**Bus Group 2-4: RWTS 66 kV Summer Peak Demand Forecasts**



**Comments on Energy at Risk**

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

For an outage of one 220/66 kV transformer at RWTS, there will be sufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for the ten year forecast period.

At the 10<sup>th</sup> percentile temperature, for an outage of one 220/66 kV transformer at RWTS, there will be insufficient capacity to supply all demand for about 20 hours in 2027/28. The energy at risk under “N-1” conditions is estimated to be 427 MWh in 2027/28. The estimated value to consumers of the 427 MWh of energy at risk is approximately \$18 million (based on a value of customer reliability of \$42,199/MWh)<sup>1</sup>. In other words, at the 10<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one 220/66 kV transformer at RWTS for the entire duration of the 2027/28 summer would lead to involuntary supply interruptions that are valued by consumers at \$18 million.

It is emphasised however, that the probability of a major transformer outage is very low, with a network average of 1.0% per transformer per annum, contributing to an expected unavailability per transformer per annum of 0.217%. When the energy at risk (427 MWh) is weighted by this low unavailability, the expected unserved energy is estimated to be around

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

2.8 MWh. This expected unserved energy is estimated to have a value to consumers of around \$0.12 million (based on a value of customer reliability of \$42,199/MWh).

In addition to the “N-1” risk identified, there is forecast to be insufficient capacity on the RWTS 66 kV bus group 1-3 to supply all demand for approximately 27 hours in 2027/28. This 10<sup>th</sup> percentile level “N” energy at risk is estimated to be 546 MWh, equating to approximately \$23 million of expected unserved energy in 2027/28 (based on a value of customer reliability of \$42,199/MWh).

These key statistics for the year 2027/28 under “N” and “N-1” outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
“N” Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0	\$0
“N-1” Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0	\$0
“N” and “N-1” Expected unserved energy at 50 <sup>th</sup> percentile demand	0	\$0
“N” Energy at risk, at 10 <sup>th</sup> percentile demand forecast	546	\$23 million
“N-1” Energy at risk, at 10 <sup>th</sup> percentile demand forecast	427	\$18 million
“N” and “N-1” Expected unserved energy at 10 <sup>th</sup> percentile demand	549	\$23 million

### Feasible options for alleviation of constraints

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

1. Implement emergency plans to transfer load to adjacent terminal stations: Both AusNet Electricity Services and United Energy have plans to enable load transfers under emergency conditions via emergency 66 kV ties, and via 22 kV feeders under system normal conditions, to the adjacent East Rowville and Templestowe terminal stations. The 22 kV feeders have a transfer capability of approximately 55 MVA. Where required, such as if a 10<sup>th</sup> percentile temperature day is anticipated, the 22 kV load transfers would be utilised to manage system normal loading to within the terminal station’s limits until augmentation is economically justified. The emergency 66 kV ties from RWTS 66 kV can be in operation within a few hours and have a transfer capability of approximately 50 MVA each.
2. Rebalance loads: Loading on bus group 1-3 is already around 70% higher than on bus group 2-4, and is forecast to grow at a much higher rate. Rebalancing loads across the two bus groups could be implemented to manage the “N” risk on bus group 1-3. AusNet Electricity Services and United Energy will jointly identify the works required to rebalance loads in the most efficient manner, following which the cost and optimal timing of the required works will be established. Under the current demand forecasts, it is expected that the optimal timing of such work would be around 2023, subject to further detailed investigation.
3. Install an additional 50 MVAR 66 kV capacitor bank: RWTS currently has two 50 MVAR 66 kV capacitor banks on 66 kV bus number 2 of the 2-4 bus group, and the station operates with a power factor around 0.97 lagging in summer. An additional 50 MVAR

66 kV capacitor bank on bus group 1-3 will help to reduce the net MVA supplied by the transformers by approximately 7.5 MVA, and would defer a network augmentation by approximately one to two years.

4. Relocate the existing 2B 50 MVAR 66 kV capacitor bank: As already noted, RWTS currently has two 50 MVAR 66 kV capacitor banks on 66 kV bus number 2 of the 2-4 bus group. With the 10<sup>th</sup> percentile loading on bus group 1-3 forecast to exceed the “N” rating of the transformers in 2022, and bus group 2-4 showing a decline in forecast demand, moving one of the existing capacitor banks from the 2-4 bus group to the 1-3 bus group will reduce the net MVA supplied by the 1-3 bus group transformers by approximately 7.5 MVA and defer a network augmentation by approximately one to two years. While moving a capacitor bank will help to manage the “N” risk, it will not address the N-1 risk.
5. Install a 5<sup>th</sup> 220/66 kV transformer at Ringwood Terminal Station: The site has provision for a 5<sup>th</sup> transformer however it will require relocation of the existing capacitor banks to free up an appropriate location for the new transformer, thereby adding to the option cost.
6. 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 a capacity augmentation.
7. Embedded Generation: Embedded generation, with a capacity in the order of 5 MW, and connected to the RWTS 66 kV bus group 1-3, could defer the need for augmentation by approximately two years.

### **Preferred network option for alleviation of constraints**

The preferred option to manage the energy at risk at the station is to rebalance loads across the two 66 kV bus groups, as identified in Option 2. AusNet Electricity Services and United Energy will jointly identify the works required to rebalance loads in the most efficient way, following which the cost and optimal timing of the required works will be established.

Prior to implementing any augmentation option it is proposed to implement the following temporary measures to cater for rare but possible high system normal loading or an unplanned outage of one of the transformers at RWTS under critical loading conditions:

- Maintain 22 kV feeder contingency plans to transfer load to adjacent terminal stations. The 22 kV feeders have a transfer capability out of the RWTS of approximately 55 MVA, and can be used to manage system normal loading if required.
- Enable load transfers under contingency conditions via emergency 66 kV ties to the adjacent East Rowville and Templestowe terminal stations, respectively. The emergency 66 kV ties from RWTS 66 kV can be in operation within a few hours and have a transfer capability of approximately 50 MVA each.
- subject to the availability of a spare 220/66 kV transformer for metropolitan areas (refer Section 5.5), a spare transformer can be used to temporarily replace a failed transformer.

The tables on the following pages provide more detailed data on the station and bus group 1-3 ratings, demand forecasts, energy at risk and expected unserved energy.

## RINGWOOD TERMINAL STATION 66kV (RWTS 66)

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

Distribution Businesses supplied by this station:

AusNet Electricity Services (77%), United Energy (23%)

Normal cyclic rating with all plant in service

675 MVA via 4 transformers (Summer peaking)

Summer N-1 Station Rating (MVA):

498 MVA [See Note 1 below for interpretation of N-1]

Winter N-1 Station Rating (MVA):

566 MVA

Station: RWTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	437.3	437.4	437.9	445.3	450.5	455.3	463.9	464.0	466.7	473.6
50th percentile Winter Maximum Demand (MVA)	326.7	327.9	331.4	336.6	337.2	340.6	344.8	345.3	347.1	349.5
10th percentile Summer Maximum Demand (MVA)	504.9	506.2	508.2	515.2	519.2	526.0	537.8	542.4	543.1	550.2
10th percentile Winter Maximum Demand (MVA)	334.8	335.8	339.5	344.5	345.9	348.7	352.9	353.5	355.6	358.1
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)	1	3	9	35	54	98	225	292	302	427
N - 1 hours at risk at 10th percentile demand (hours)	1	2	4	4	6	8	14	16	17	20
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	0.1	0.3	0.5	0.9	2.0	2.5	2.6	3.7
Expected Unserved Energy value at 50th percentile demand	\$0.00M									
Expected Unserved Energy value at 10th percentile demand	\$0.00M	\$0.00M	\$0.00M	\$0.01M	\$0.02M	\$0.04M	\$0.08M	\$0.11M	\$0.11M	\$0.16M
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	\$0.01M	\$0.01M	\$0.02M	\$0.03M	\$0.03M	\$0.05M

#### 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 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50<sup>th</sup> and 10<sup>th</sup> percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))

**RINGWOOD TERMINAL STATION 66kV Bus group 1-3 (RWTS13 66)****Detailed data: Magnitude and probability of loss of load**

Distribution Businesses supplied by this station:  
Normal cyclic rating with all plant in service

AusNet Electricity Services (77%), United Energy (23%)  
326 MVA via 2 transformers (Summer peaking)

Station: Bus group 1-3 RWTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	278.1	279.7	281.4	286.9	291.9	295.9	302.2	304.4	307.6	312.7
50th percentile Winter Maximum Demand (MVA)	199.2	199.9	201.2	203.3	203.4	204.9	206.8	207.1	207.9	209.0
10th percentile Summer Maximum Demand (MVA)	320.2	323.3	326.4	332.3	337.3	343.0	352.1	357.4	360.5	366.4
10th percentile Winter Maximum Demand (MVA)	203.9	204.5	206.0	208.0	208.5	209.8	211.8	212.1	213.1	214.3
N energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	0	0	0
N hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	0	0	0
N energy at risk at 10th percentile demand (MWh)	0	0	1	21	47	97	230	334	401	546
N hours at risk at 10th percentile demand (hours)	0	0	1	4	7	11	18	22	24	27
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	0.8	20.6	47.3	96.8	229.7	333.6	401.3	545.7
Expected Unserved Energy value at 50th percentile demand	\$0.00M	\$0.00M	\$0.00M							
Expected Unserved Energy value at 10th percentile demand	\$0.00M	\$0.00M	\$0.03M	\$0.87M	\$2.00M	\$4.08M	\$9.69M	\$14.08M	\$16.93M	\$23.03M
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	\$0.26M	\$0.60M	\$1.22M	\$2.91M	\$4.22M	\$5.08M	\$6.91M

## Notes:

7. "N" means cyclic station output capability rating with all transformers in service. The rating is at an summer ambient temperature of 35 degrees Centigrade.
8. "N energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N capability rating.
9. "N hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N capability rating.
10. "Expected unserved energy" equals "energy at risk" under "N" conditions.
11. 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.
12. The 0.7 and 0.3 weightings applied to the 50<sup>th</sup> and 10<sup>th</sup> percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))

## SHEPPARTON TERMINAL STATION (SHTS) 66 kV

Shepparton Terminal Station (SHTS) 66 kV consists of three 150 MVA 220/66 kV transformers and is the main source of supply for over 72,215 customers in Shepparton and the Goulburn–Murray area. The station supply area includes the towns of Shepparton, Echuca, Mooroopna, Yarrawonga, Kyabram, Cobram, Numurkah, Tatura, Rochester, Nathalia, Tongala, and Rushworth.

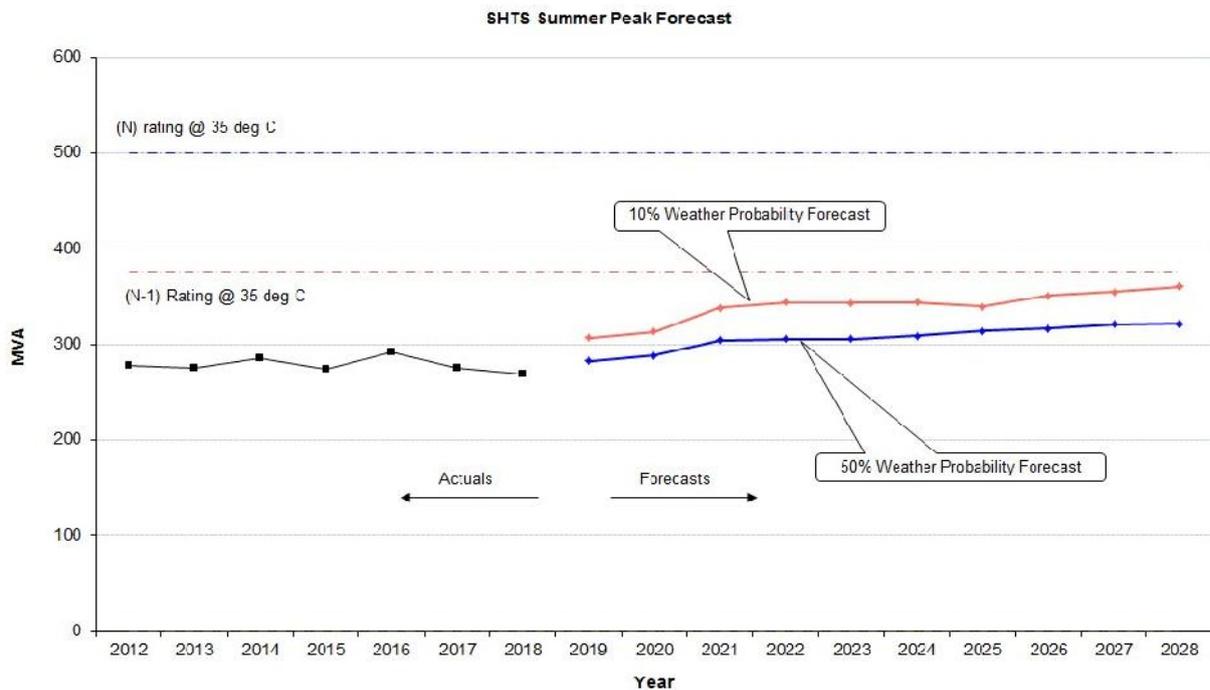
### Magnitude, probability and impact of loss of load

Demand at SHTS is summer peaking. Growth in summer peak demand at SHTS has averaged around -1.36 MVA (-0.4%) per annum over the last 5 years. Peak load on the station in the summer of 2017 reached 259.7 MW.

It is estimated that:

- For 6 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile forecast.
- The station load power factor at the time of peak demand is 0.97.

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



The chart shows there is sufficient capacity at the station to supply all expected demand at the 50<sup>th</sup> and 10<sup>th</sup> percentile temperature, over the forecast period even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

## SOUTH MORANG TERMINAL STATION (SMTS 66 kV)

### Background

A 220/66 kV connection station with two 220/66 kV 225 MVA transformers was established at the existing South Morang Terminal Station (SMTS) site in 2008. The re-arrangement of 66 kV loops with the establishment of SMTS resulted in the 160 MW Somerton Power Station being connected to the SMTS 66 kV bus.

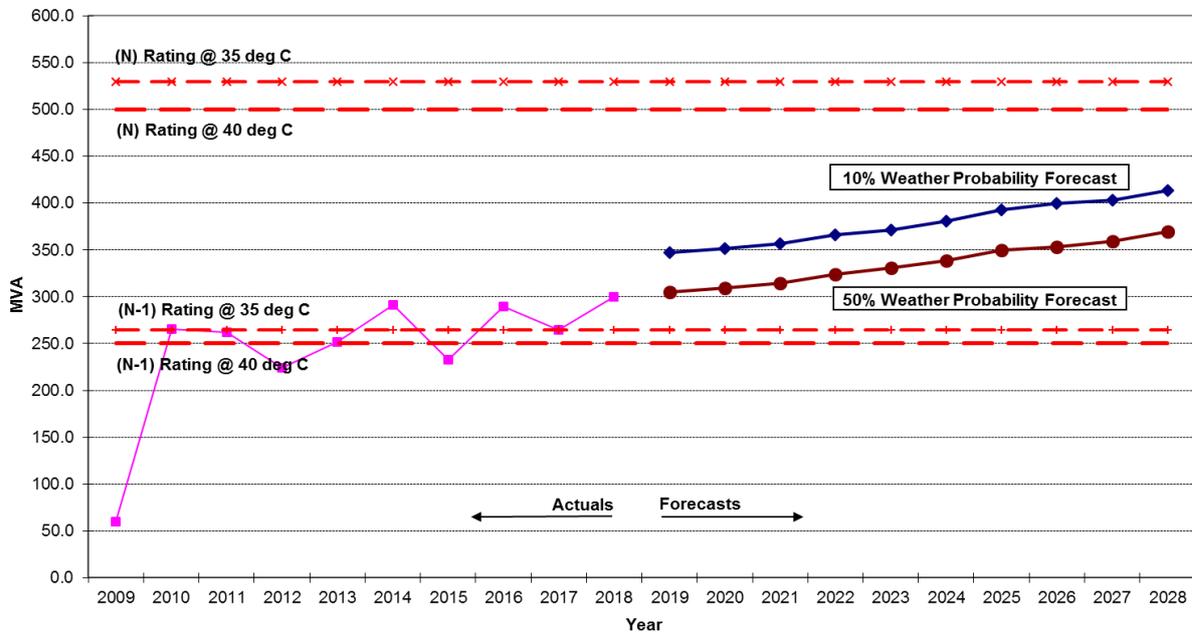
The geographic coverage of the area supplied by the new connection assets at SMTS spans from Seymour, Kilmore, Kalkallo, Kinglake and Rubicon in the north to Mill Park in the south and from Doreen and Mernda in the east to Somerton and Craigieburn in the west. The electricity distribution networks for this area are the responsibility of both AusNet Electricity Services (71%) and Jemena Electricity Networks (29%).

The recorded peak demand in summer 2017/18 was 295.3 MW (299.7 MVA) which exceeded the previous recorded maximum demand of 284.7 MW (291.6 MVA) set in summer 2013/14. The station load has a power factor of 0.99 at maximum demand. Demand is expected to exceed 95% of the 50<sup>th</sup> percentile peak demand for 4 hours per annum.

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

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

SMTS 66 kV Summer Peak Demand Forecasts

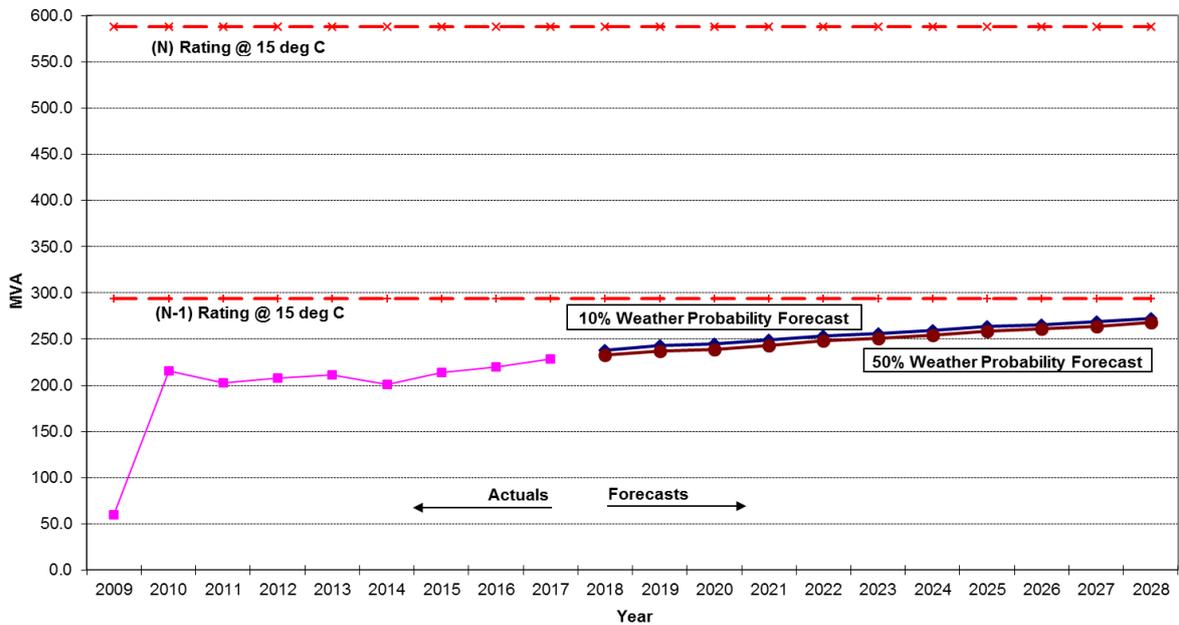


The “N” rating on the above chart indicates the maximum load that can be supplied from SMTS with both transformers in service.

With the projected growth in customer demand in the area, it is expected that SMTS will continue to exceed its “N-1” rating in summer at the 50<sup>th</sup> percentile and 10<sup>th</sup> percentile summer demand forecasts, as shown in the graph above.

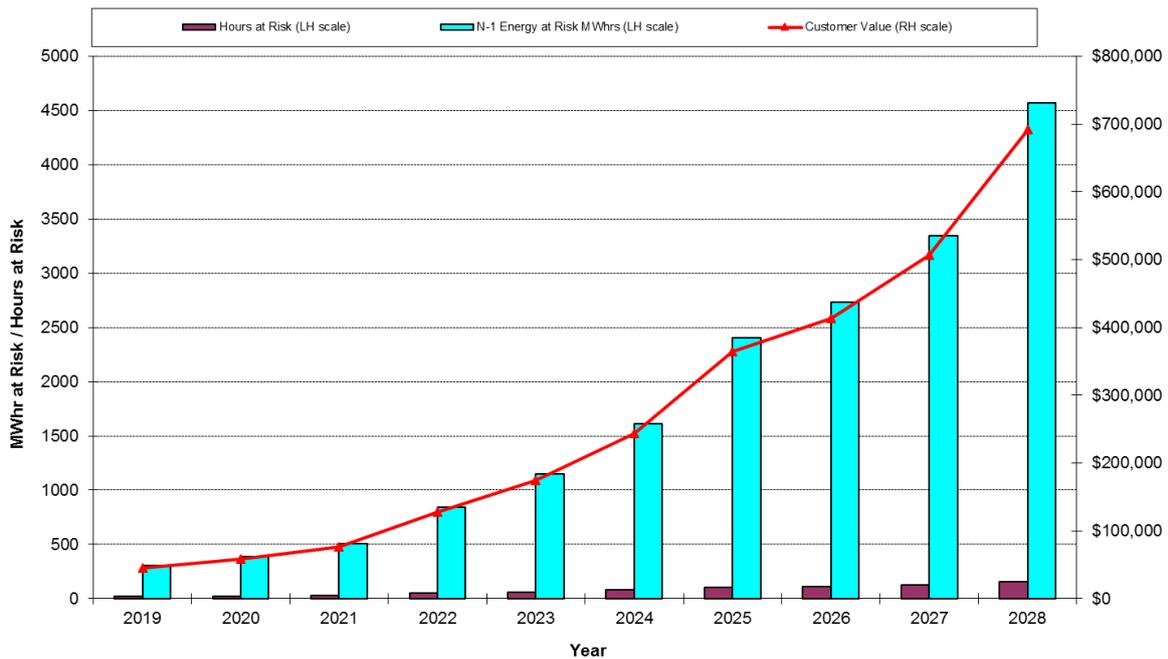
In the winter, the rating of the transformers is higher than the summer rating due to lower ambient temperatures. Thus, energy at risk during the winter period is generally lower than the summer period. The graph below demonstrates the 10<sup>th</sup> and the 50<sup>th</sup> percentile winter maximum demand forecast together with the station’s operational “N” rating and “N-1” rating. SMTS is expected to remain within its “N-1” rating under both 50<sup>th</sup> percentile and 10<sup>th</sup> percentile winter maximum demand forecasts for the 10 year planning horizon.

**SMTS 66 kV Winter Peak Demand Forecasts**



The bar chart below depicts the energy at risk over the winter and summer periods with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours each year that the 50<sup>th</sup> percentile demand forecast is expected to exceed the “N-1” station capability. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50<sup>th</sup> percentile demand forecast.

Annual Energy and Hours at Risk at SMTS 66 (Single Contingency Only)



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

**Comments on Energy at Risk assuming Somerton Power Station is unavailable**

Assuming that Somerton Power Station is unavailable, then for an outage of one transformer at SMTS over the entire summer period, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 158 hours in summer 2027/28. The energy at risk at the 50<sup>th</sup> percentile temperature under “N-1” conditions is estimated to be 4,569 MWh in summer 2027/28. The estimated value to consumers of the 4,569 MWh of energy at risk is approximately \$160 million (based on a value of customer reliability of \$34,952 MWh)<sup>1</sup>. In other words, at the 50<sup>th</sup> percentile demand level, without any contribution from embedded generation and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at SMTS in summer 2027/28 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$160 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (4,569 MWh) is weighted by this low transformer unavailability, the expected unserved energy is estimated to be around 20.0 MWh. This expected unserved energy is estimated to have a value to consumers of around \$0.69 million (based on a value of customer reliability of \$34,952/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) temperatures occurring each

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

year. Under higher temperature conditions (that is, at the 10<sup>th</sup> percentile level), the energy at risk in 2027/28 summer is estimated to be 10,964 MWh. The estimated value to consumers of the energy at risk in 2027/28 summer is approximately \$383 million. The corresponding value of the expected unserved energy (of 48.0 MWh) is approximately \$1.66 million.

These key statistics for the summer of 2027/28 under “N-1” outage conditions are summarised in the table below.

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	4,569	\$160 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	20.0	\$0.69 million
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	10,964	\$383 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	48.0	\$1.66 million

If one of the 220/66 kV transformers at SMTS is taken off line during peak loading times and the “N-1” station rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA), which is operated by AusNet Transmission Group’s TOC<sup>2</sup> to protect the connection assets from overloading<sup>3</sup>, will act swiftly to reduce the loads in blocks to within safe loading limits. In the event of OSSCA operating, it would automatically shed up to 40 MVA of load, affecting approximately 15,000 customers in 2018/19. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at feeder level in accordance with AusNet Electricity Services and Jemena’s operational procedures after the operation of the OSSCA scheme.

### **Comments on Energy at Risk assuming Somerton Power Station is available**

The previous comments on energy at risk are based on the assumption that there is no embedded generation available to offset the 220/66 kV transformer loading. The Somerton Power Station (SPS) is capable of generating up to 160 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 peak demand at SMTS will coincide with periods of high wholesale electricity prices, resulting in a high likelihood that SPS will be generating. If SPS is generating to its full capacity there would be no energy at risk at SMTS over the ten year planning horizon for both the 50<sup>th</sup> and 10<sup>th</sup> 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 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

<sup>2</sup> Transmission Operation Centre.

<sup>3</sup> 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.

to 20 MVA of load transfers via existing 22 kV feeders to adjoining zone substations. Jemena has plans and the capability to transfer an additional 13 MVA. This option is able to partly reduce the interruption duration and load at risk resulting from a major transformer failure.

2. Install a third 225 MVA 220/66 kV transformer at South Morang Terminal Station (SMTS), which would also require the installation of fault limiting reactors.
3. Demand Management. AusNet Electricity Services is currently using an MVA tariff to encourage large customers to improve their power factor as well as a critical peak pricing tariff to encourage them to reduce load at peak demand times and thus reduce the station loading. Up to 50% of the maximum demand at SMTS 66 kV is expected to be summer residential load, largely air conditioning. With the existing load mix it is likely that demand reduction initiatives can play a limited role in reducing the peak summer load at SMTS 66 kV.
4. Embedded Generation. As mentioned above, the Somerton power station is connected to SMTS. A network support agreement with SPS or other generators connected to the SMTS 66 kV bus will help to defer the need for augmentation.

### **Preferred network option for alleviation of constraints**

1. In the event that there are no firm commitments by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce future load at SMTS 66 kV; it will be proposed to install a new third 220/66 kV transformer at SMTS 66 kV. The capital cost of this option is estimated at \$22 million, which includes the cost of installing three fault limiting reactors. This equates to a total annual cost of approximately \$1.3 million per annum. Under the latest demand forecast, the installation of the third transformer at SMTS would not be economically justified in the forecast period.
2. Implement the following temporary measures to cater for an unplanned outage of one transformer at SMTS under critical loading conditions until the new 220/66 kV transformer is commissioned:
  - maintain contingency plans to transfer load quickly to adjacent terminal stations;
  - rely on Somerton Power Station (SPS) generation to reduce loading at SMTS 66 kV, and investigate the option of formalising a network support agreement with SPS;
  - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading; and
  - subject to the availability of AusNet Transmission Group's spare 220/66 kV transformer for the metropolitan area (refer Section 5.5), this spare transformer can be used to temporarily replace a failed transformer at SMTS. It is noted that AusNet Transmission Group currently has two 150 MVA spare transformers. Load sharing with a metro spare transformer will not be optimal, so the SMTS 66 kV capacity will be reduced under these emergency conditions.

The table on the following page provides more detailed data on the station rating, demand forecast, energy at risk and expected unserved energy assuming embedded generation is not available.

**SOUTH MORANG TERMINAL STATION (SMTS 66 kV)****Detailed data: Magnitude and probability of loss of load**

Distribution Businesses supplied by this station: AusNet Electricity Services (71%) and Jemena Electricity Networks (29%).

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

<b>Station: SMTS 66 kV</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>
50th percentile Summer Maximum Demand (MVA)	305.4	309.6	314.6	324.4	331.0	338.9	349.4	353.1	359.4	370.0
50th percentile Winter Maximum Demand (MVA)	236.9	238.9	242.8	248.2	250.4	254.4	258.9	261.1	264.1	267.6
10th percentile Summer Maximum Demand (MVA)	347.0	351.4	356.7	366.1	371.5	380.8	392.7	399.3	403.3	413.8
10th percentile Winter Maximum Demand (MVA)	242.9	245.0	248.9	253.1	255.8	259.3	263.8	265.9	269.1	272.7
N - 1 energy at risk at 50th percentile demand (MWh)	301	384	504	841	1,148	1,610	2,406	2,730	3,347	4,569
N - 1 hours at risk at 50th percentile demand (hours)	20	23	30	48	59	78	103	111	129	158
N - 1 energy at risk at 10th percentile demand (MWh)	2,290	2,588	2,981	3,808	4,356	5,402	7,075	8,165	8,888	10,964
N - 1 hours at risk at 10th percentile demand (hours)	76	83	95	118	131	157	206	231	247	291
Expected Unserved Energy at 50th percentile demand (MWh)	1	2	2	4	5	7	10	12	15	20
Expected Unserved Energy at 10th percentile demand (MWh)	10	11	13	17	19	23	31	35	39	48
Expected Unserved Energy value at 50th percentile demand	\$0.05M	\$0.06M	\$0.08M	\$0.13M	\$0.17M	\$0.24M	\$0.36M	\$0.41M	\$0.51M	\$0.69M
Expected Unserved Energy value at 10th percentile demand	\$0.35M	\$0.39M	\$0.45M	\$0.58M	\$0.66M	\$0.82M	\$1.07M	\$1.24M	\$1.35M	\$1.66M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$0.14M	\$0.16M	\$0.19M	\$0.26M	\$0.32M	\$0.42M	\$0.58M	\$0.66M	\$0.76M	\$0.98M

## Notes:

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

## SPRINGVALE TERMINAL STATION (SVTS)

Springvale Terminal Station (SVTS) is located in the south east of greater Melbourne. The geographic coverage of the station's supply area spans from Blackburn in the north to Noble Park in the south and from Wantirna South in the east to Riversdale in the west. The electricity supply network for this large region is split between United Energy (UE) and CitiPower (CP).

### Background

SVTS was augmented with a new 150 MVA 220/66 kV transformer in 2006 to reinforce the security and reliability of supply for customers in the area. The station now has four 150 MVA 220/66 kV transformers and operates in a split bus arrangement. Under system normal conditions the No.1 & No.2 transformers (B1 & B2) are operated in parallel as one group (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 capabilities of the two transformers B1 & B2 at all times.
- Load demand on the SVTS 3466 group should be kept within the capabilities of the two transformers B3 & B4 at all times.
- Load demand on the total station should be kept within the capabilities of any three transformers when one transformer is out of service.

SVTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 478 MW (491 MVA) in summer 2009 under extreme weather conditions. The peak demand in summer 2018 was 403.3 MW (410.6 MVA). Six embedded generation units (3 which operate only as a backup supply) over 1 MW are connected at SVTS 66 kV.<sup>1</sup>

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

### SVTS 1266 (B12) Bus Group Summer Peak Forecasts

This bus group supplies Noble Park, Springvale South, Clarinda, Oakleigh East, Springvale and Springvale West zone substations owned by United Energy. Four generation units over 1 MW are connected at SVTS 1266 (B12) bus group.<sup>1</sup>

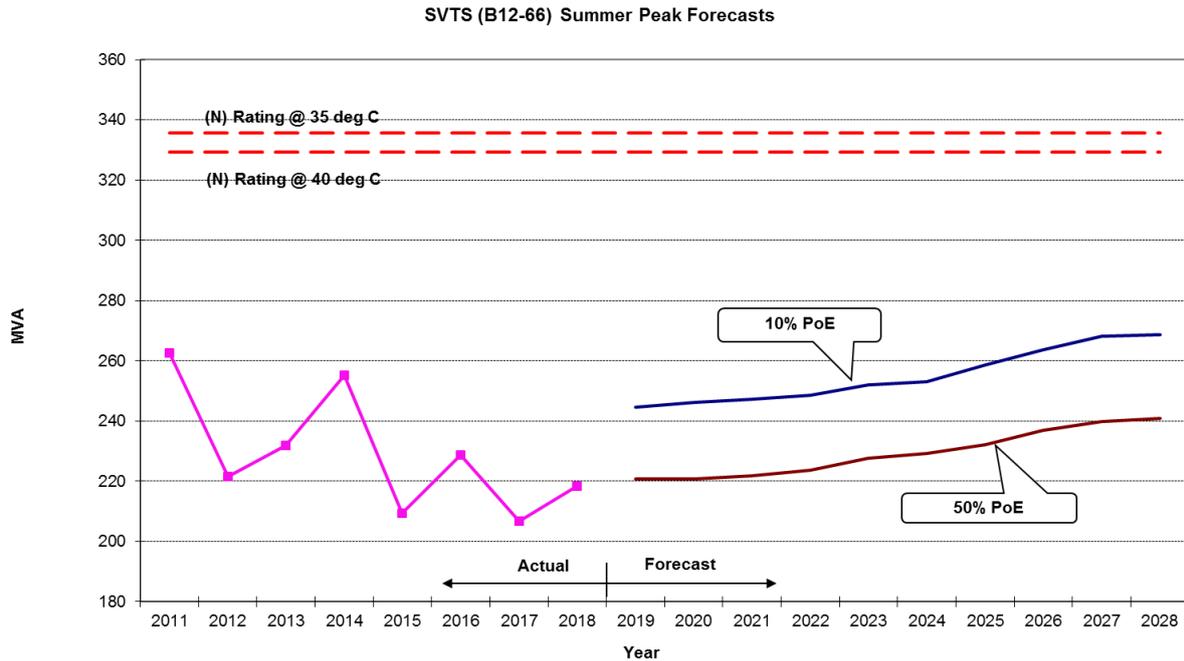
The recorded peak demand in summer 2018 for the SVTS 1266 group was 211.4 MW (218.4 MVA). The load at SVTS 1266 (B12) is forecast to have a power factor of 0.985 at times of peak demand.

United Energy's new Keysborough zone substation was commissioned in 2014. Approximately 15 MW of demand was transferred away from SVTS to HTS. This load transfer is reflected in the graph below.

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<sup>1</sup> The maximum demand forecasts adopted in this risk analysis exclude the impact of generation schemes.

The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand for SVTS 1266 and the corresponding rating with both transformers in service.



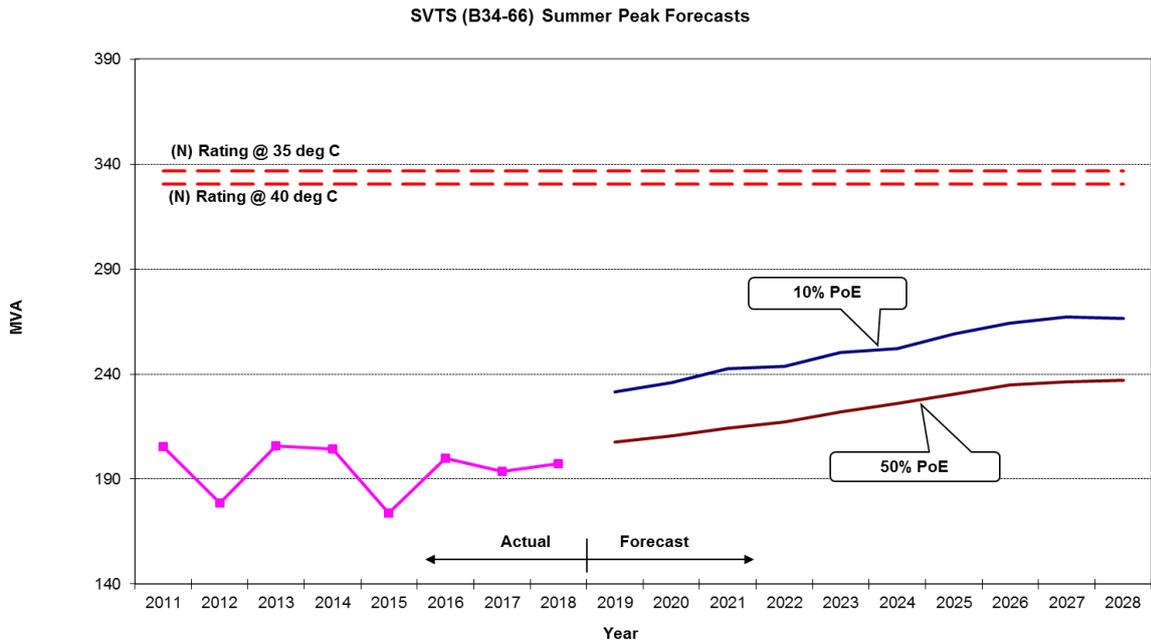
The graph above shows that with both transformers in service, there is adequate capacity to meet the anticipated maximum demand for the entire planning period.

**SVTS 3466 (B34) Bus Group Summer Peak Forecasts**

This bus group supplies East Burwood, Glen Waverley and Notting Hill zone substations owned by United Energy and Riversdale zone substation owned by CitiPower. Two generation units over 1 MW are connected at SVTS 3466 (B34) bus group.<sup>1</sup>

The recorded peak demand in summer 2018 for the SVTS 3466 group was 193.8 MW (197.5 MVA). The load at SVTS 3466 (B12) is forecast to have a power factor of 0.984 at times of peak demand.

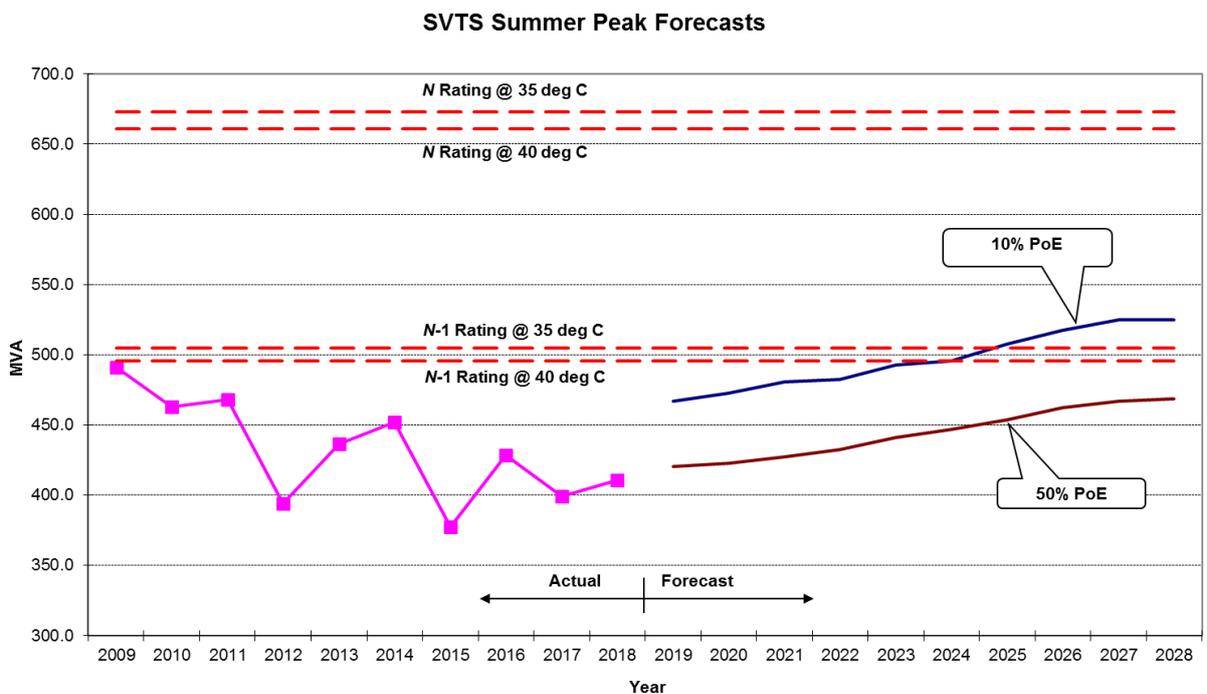
The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand for SVTS3466 and the corresponding rating with both transformers in service.



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

### SVTS Total Summer Peak Forecasts

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

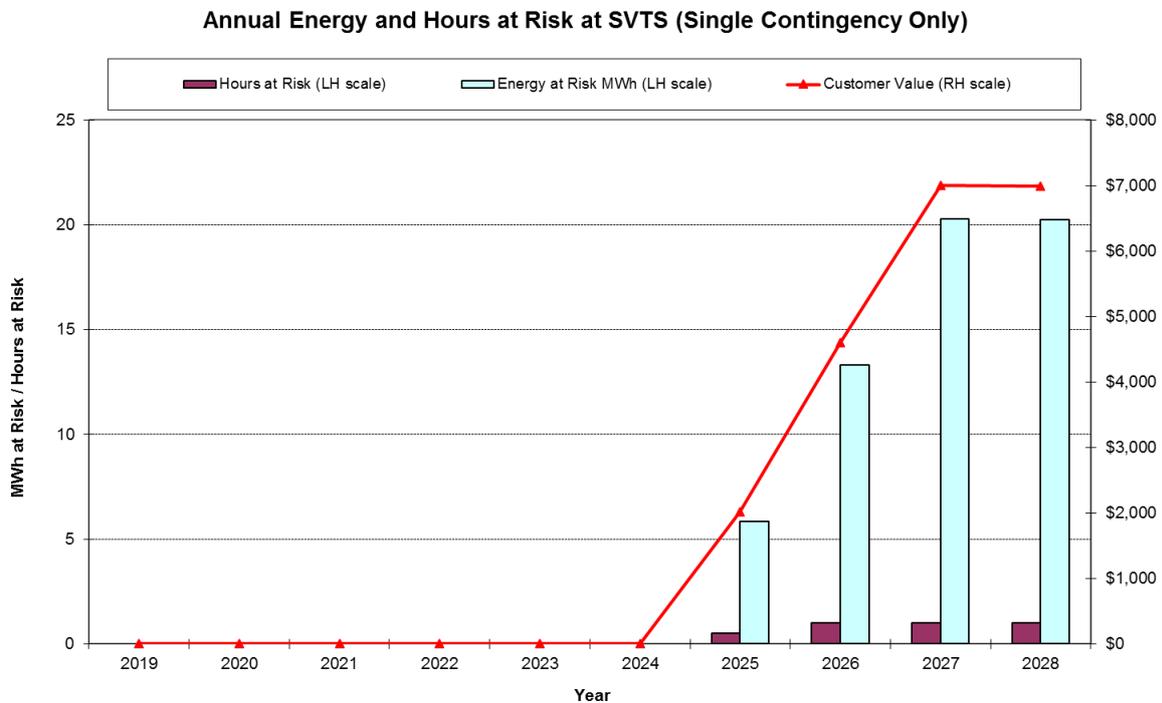


The N rating on the graph indicates the maximum load that can be supplied from SVTS with all transformers in service. Exceeding this level will require load shedding or emergency load transfers to keep the terminal station operating within its limits.

The graph indicates that the demand at SVTS 66 kV remains below its N rating within the ten year planning period. However, the 10<sup>th</sup> percentile overall summer maximum demand is forecast to exceed the station’s (N-1) rating at 40°C from summer 2025, while the 50<sup>th</sup> percentile summer maximum demand is forecast to remain below its (N-1) rating.

The overall station load is forecast to have a power factor of 0.983 at times of peak demand. The demand at SVTS 66 kV is expected to exceed 95% of the peak demand for approximately 6 hours per annum.

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



**Comments on Energy at Risk**

For an outage of one transformer at SVTS, it is expected that from 2025, there would be insufficient capacity at the station to supply all demand at the 10<sup>th</sup> percentile temperature.

By the end of the ten-year planning period in 2028, the energy at risk under N-1 conditions is estimated to be 20 MWh at the 10<sup>th</sup> percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 1 hour in that year. The estimated value to customers of the 20 MWh of energy at risk in 2028 is approximately \$0.81 million (based on a value of customer reliability of \$40,192/MWh)<sup>2</sup>. In other words, at the 10<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be

<sup>2</sup> 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.

taken to mitigate the impact of a forced outage, a major outage of one transformer at SVTS over the summer of 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$0.81 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (20 MWh in 2027) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.17 MWh. This expected unserved energy is estimated to have a value to consumers of around \$7,000 (based on a value of customer reliability of \$40,192/MWh). AusNet Transmission Group has indicated that three of the four transformers at SVTS have an elevated failure risk due to the age and condition of the transformers. Therefore the expected unserved energy calculated above may underestimate the risk at this station. Given that AusNet Transmission Group plans to replace these transformers as part of its asset replacement program in 2021 it is not economical to advance any augmentation works at SVTS.<sup>3</sup>

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of 10<sup>th</sup> percentile temperatures occurring in each year. Under 50<sup>th</sup> percentile temperature conditions, there is no energy at risk as maximum demand is within the station's N-1 rating.

These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0	\$0
Expected unserved energy at 50 <sup>th</sup> percentile demand	0	\$0
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	20	\$0.81 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	0.17	\$7,000

If one of the 220/66 kV transformers at SVTS is taken off line during peak loading times and the (N-1) station rating is exceeded, the OSSCA<sup>4</sup> load shedding scheme which is operated by AusNet Transmission Group's NOC<sup>5</sup> will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with United Energy's and CitiPower's operational procedures after the operation of the OSSCA scheme.

<sup>3</sup> The 2018 Victorian Annual Planning Report (VAPR) provides further information on AusNet Transmission Group's asset renewal program. It is available from: <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report>

<sup>4</sup> Overload Shedding Scheme of Connection Asset.

<sup>5</sup> Network Operations Centre

## Feasible options for alleviation of constraints

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

1. Implement a contingency plan to transfer load to adjacent terminal stations. Both United Energy and CitiPower have established and implemented the necessary plans that enable load transfers under contingency conditions via the 66 kV subtransmission and/or the high voltage 22 kV and 11 kV distribution networks. These plans are reviewed annually prior to the summer season. The total transfer capability away from SVTS 66 kV onto adjacent terminal stations via distribution network is assessed at 61 MVA for summer 2019.
2. Establish a new 220/66 kV terminal station (DNST) in the Dandenong area to off-load SVTS.

In early 2012 United Energy submitted a preliminary connection enquiry to AEMO for the establishment of a new connection point in the Dandenong area. Joint planning activities have been underway between the two organisations to quantify the risk of the emerging constraints in the area and to assess viable options for alleviating the constraints. The investigations identified that the need is driven mainly by load-at-risk associated with the 220kV line constraints in the area. This assessment identified the timing requirement for a new Dandenong Terminal Station (DNST) to be before summer 2027 with associated sub-transmission works carried out to transfer load from zone substations in the vicinity to the new connection point.

The capital cost of installing a new 220/66 kV terminal station in Dandenong is estimated to be in excess of \$70 million. The estimated total annual cost of this network augmentation is approximately \$4.1 million.

Since this study was completed there has been a reduction in the net maximum demand forecast at Heatherton Terminal Station (HTS) and SVTS and an increase in ratings at HTS, and so the new terminal station is not likely to be economically justified within the ten year planning horizon. United Energy will continue to work with AEMO on this joint planning exercise.

3. Install a third 225 MVA 220/66 kV transformer at Malvern terminal station (MTS) to off-load SVTS.
4. Install a fifth 150 MVA 220/66 kV transformer at SVTS.
5. Replace three of the four SVTS 220/66 kV transformers in 2021, as part of AusNet Transmission Group's asset replacement programme. AusNet Transmission Group intends to replace three of the four existing transformers with like-for-like transformers. AusNet Transmission Group has indicated that the station's (N-1) rating is expected to be similar to (or marginally higher than) the current level.

## Preferred network option(s) for alleviation of constraints

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at SVTS under critical loading conditions:
  - maintain contingency plans to transfer load quickly to adjacent terminal stations;
  - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any automatic load shedding that may take place; and
  - subject to the availability of AusNet Transmission Group's metropolitan spare 220/66 kV transformer (refer to Section 4.5), this spare transformer can be used to temporarily replace the failed transformer.
2. Replace three of the four SVTS 220/66 kV transformers in 2021, as part of AusNet Transmission Group's asset replacement program.
3. Establish a new 220/66 kV terminal station in the Dandenong area to off-load SVTS.

On the present forecasts, establishment of a new terminal station in the Dandenong area is unlikely to be economically justified within the ten year planning horizon, but may be economically viable shortly after.

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



## SPRINGVALE TERMINAL STATION 66 kV

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

**Distribution Businesses supplied by this station:** United Energy (94.5%) and CitiPower 5.5%)  
**Station operational rating (N elements in service):** 673 MVA via 4 transformers (Summer peaking)  
**Summer N-1 Station Rating:** 505 MVA [See Note 1 below for interpretation of N-1]  
**Winter N-1 Station Rating:** 560 MVA

Station: SVTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	420	423	427	432	441	447	454	463	467	469
50th percentile Winter Maximum Demand (MVA)	324	325	325	325	326	329	331	333	335	337
10th percentile Summer Maximum Demand (MVA)	467	473	481	482	493	496	508	517	525	525
10th percentile Winter Maximum Demand (MVA)	329	331	331	331	333	336	338	340	343	345
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	6	13	20	20
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	1	1	1	1
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2
Expected Unserved Energy value at 50th percentile demand	\$0.0k									
Expected Unserved Energy value at 10th percentile demand	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$2.0k	\$4.6k	\$7.0k	\$7.0k
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	\$0.6k	\$1.4k	\$2.1k	\$2.1k

#### Notes:

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

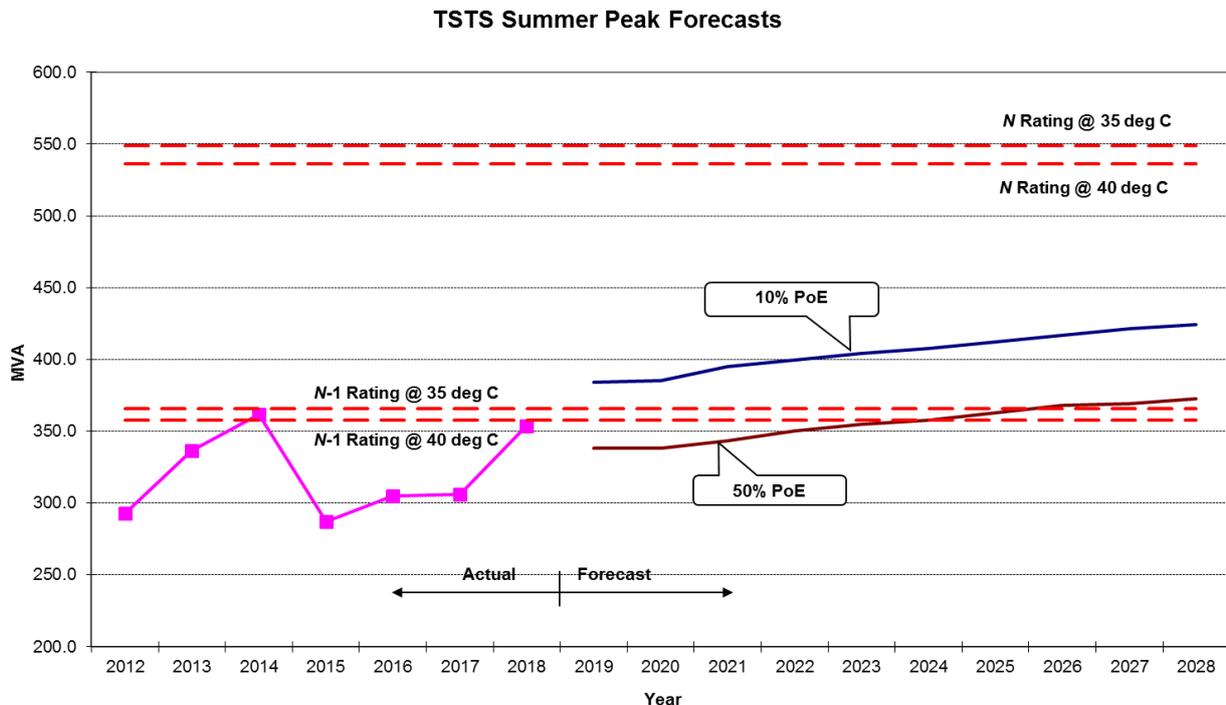
## TEMPLESTOWE TERMINAL STATION (TSTS)

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

TSTS 66 kV is a summer critical terminal station. The station reached its highest recorded peak demand of 357.6 MW (377.1 MVA) in summer 2009 under extreme weather conditions. The peak demand in summer 2018 was 340.2 MW (353.6 MVA). There is one embedded generation unit over 1 MW connected at TSTS.<sup>1</sup>

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

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



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

The graph indicates that the overall demand at TSTS remains below its N rating within the 10 year planning period. The 50<sup>th</sup> percentile summer peak demand is not expected to exceed the station’s (N-1) rating at 35°C until 2026. However, the 10<sup>th</sup> percentile summer peak demand is forecast to exceed the station’s (N-1) rating at 35°C and 40°C from summer 2019.

<sup>1</sup> The maximum demand forecasts adopted in this risk analysis exclude the impact of generation schemes.

The demand at TSTS 66 kV is expected to exceed 95% of the peak demand for approximately 3 hours per annum. The station load has a power factor of 0.967 at times of peak demand.

### Comments on Energy at Risk

For an outage of one transformer at TSTS, it is expected that there would be sufficient capacity at the station to supply demand at the 50<sup>th</sup> percentile temperature until 2026.

By the end of the ten-year planning period in 2028, the energy at risk under N-1 conditions is 5 MWh at the 50<sup>th</sup> percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 2 hours in that year. The estimated value to customers of the 5 MWh of energy at risk in 2028 is approximately \$0.18 million (based on a value of customer reliability of \$35,172/MWh)<sup>2</sup>. In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TSTS over the summer of 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$0.18 million.

It is emphasised however, that the probability of a major outage of one of the three transformers occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (5 MWh in 2028) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.03 MWh. This expected unserved energy is estimated to have a value to consumers of around \$1,100 (based on a value of customer reliability of \$35,172/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2028 is estimated to be 172 MWh. The estimated value to consumers of this energy at risk in 2028 is approximately \$6.1 million. The corresponding value of the expected unserved energy (of 1.1 MWh) is approximately \$39,000.

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 is evaluating the economic feasibility of replacing one or both old transformers at TSTS, and will initiate an asset replacement project in 2019 to address the asset failure risk. Given that AusNet Transmission Group plans to replace at least one of the transformers as part of its asset replacement program, the elevated failure rates are unlikely to advance any augmentation works at this terminal station.<sup>3</sup>

These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

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<sup>2</sup> 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.

<sup>3</sup> Chapter 5 of the 2016 Victorian Annual Planning Report provides further details of AusNet Transmission Group's asset renewal program. It is available from:  
<http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report>

	MWh	Valued at consumer interruption cost
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	5	\$0.18 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	0.03	\$1,100
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	172	\$6.1 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	1.1	\$39,000

If one of the 220/66 kV transformers at TSTS is taken off line during peak loading times and the (N-1) station rating is exceeded, the OSSCA<sup>4</sup> load shedding scheme which is operated by AusNet Transmission Group's TOC<sup>5</sup> will act swiftly to reduce the loads in blocks to within safe loading limits. Any load reductions that are in excess of the minimum amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with each distribution company's operational procedures after the operation of the OSSCA scheme.

In the case of TSTS supply at maximum loading periods, the OSSCA scheme would shed about 80 MW of load, affecting approximately 26,200 customers in 2019.

### Feasible options for alleviation of constraints

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

1. Implement a contingency plan to transfer load to adjacent terminal stations. United Energy, CitiPower, AusNet Electricity Services and Jemena Electricity Networks have established and implemented the necessary plans that enable load transfers under contingency conditions. These plans are reviewed annually prior to the summer season. The total transfer capability away from TSTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 64 MVA for summer 2018-19.
2. Establish a new 220/66 kV terminal station. Two terminal station sites, one in Doncaster (DCTS) and another in Kew (KWTS), have been reserved for possible future electrical infrastructure development to meet customers' needs in the area. With established 220 kV tower lines to both sites, development of either of these sites could be economic depending upon the geographical location of additional customer load.
3. Install a fourth 150 MVA 220/66 kV transformers at TSTS. There is provision in the yard for an additional transformer.

The capital cost of installing a 220/66 kV transformer at TSTS 66 kV is estimated to be \$20 million. The estimated total annual cost of this network augmentation is approximately \$1.2 million.

On the present maximum demand forecasts, the fourth 220/66 kV transformer is not likely to be required within the ten year planning horizon.

<sup>4</sup> Overload Shedding Scheme of Connection Asset.

<sup>5</sup> Transmission Operations Centre.

## Preferred network option(s) for alleviation of constraints

1. Implement the following temporary measures to cater for an unplanned outage of one transformer at TSTS under critical loading conditions:
  - maintain contingency plans to transfer load quickly to adjacent terminal stations;
  - fine-tune the OSSCA scheme settings in conjunction with TOC to minimise the impact on customers of any load shedding that may take place; and
  - subject to the availability of AusNet Transmission Group's spare 220/66 kV transformer for metropolitan areas (refer to Section 4.5), this spare transformer can be used to temporarily replace the failed transformer.
2. Install a fourth 150 MVA 220/66 kV transformers at TSTS.

In the absence of any commitment by interested parties to offer network support services by installing local generation or through demand side management initiatives that would reduce load at TSTS, it is proposed to install a fourth 220/66 kV transformer at TSTS. On the present forecasts, an additional 220/66 kV transformer is unlikely to be economic within the ten year planning horizon.

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

## TEMPLESTOWE TERMINAL STATION 66 kV

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

**Distribution Businesses supplied by this station:** United Energy (39%), CitiPower (31%), AusNet Electricity Services (21%), Jemena (9%)  
**Station operational rating (N elements in service):** 549 MVA via 3 transformers (Summer peaking)  
**Summer N-1 Station Rating:** 366 MVA [See Note 1 below for interpretation of N-1]  
**Winter N-1 Station Rating:** 417 MVA

Station: TSTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	338	338	344	350	355	358	363	368	369	373
50th percentile Winter Maximum Demand (MVA)	247	249	252	254	256	259	262	264	265	267
10th percentile Summer Maximum Demand (MVA)	384	385	395	399	404	408	412	417	421	425
10th percentile Winter Maximum Demand (MVA)	257	259	262	264	266	269	272	274	276	278
N-1 energy at risk at 50th percentile demand (MWh)	0	0	0	0	0	0	0	1	1	5
N-1 hours at risk at 50th percentile demand (hours)	0	0	0	0	0	0	0	1	1	2
N-1 energy at risk at 10th percentile demand (MWh)	32	34	55	70	83	95	113	135	152	172
N-1 hours at risk at 10th percentile demand (hours)	3	3	3	3	4	4	5	5	7	7
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)	0.2	0.2	0.4	0.5	0.5	0.6	0.7	0.9	1.0	1.1
Expected Unserved Energy value at 50th percentile demand	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.2k	\$0.3k	\$1.1k
Expected Unserved Energy value at 10th percentile demand	\$7.3k	\$7.7k	\$12.6k	\$15.8k	\$18.9k	\$21.5k	\$25.8k	\$30.6k	\$34.6k	\$39.1k
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$2.2k	\$2.3k	\$3.8k	\$4.7k	\$5.7k	\$6.5k	\$7.7k	\$9.3k	\$10.6k	\$12.5k

#### Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. For 50<sup>th</sup> percentile value, the rating is at an ambient temperature of 35 degrees Centigrade. For 10<sup>th</sup> percentile value, the rating is at an ambient temperature of 40 degrees Centigrade.
2. "N-1 energy at risk" is the amount of energy in a year during which the specified demand forecast exceeds the N-1 capability rating. Energy at risk at the specified demand forecast when all plant is in service (N) is shown separately.
3. "N-1 hours per year at risk" is the number of hours in a year during which the specified demand forecast exceeds the N-1 capability rating. Hours at risk at the specified demand forecast when all plant is in service (N) are shown separately.
4. "Expected unserved energy" means "energy at risk" multiplied by the probability of a major outage affecting one transformer. "Major outage" means an outage with duration of 2.6 months. The outage probability is derived from the base reliability data given in Section 5.4.
5. The value of unserved energy is derived from the sector values given in Table 1 of Section 2.4, weighted in accordance with the composition of the load at this terminal station.
6. The 0.7 and 0.3 weightings applied to the 50<sup>th</sup> and 10<sup>th</sup> percentile expected unserved energy estimates (respectively) are in accordance with the approach applied by AEMO, and described on page 12 of its publication titled *Victorian Electricity Planning Approach*, published in June 2016 (see [http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/Victorian\\_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx](http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.ashx))

## TERANG TERMINAL STATION (TGTS) 66kV

Terang Terminal Station (TGTS) 66 kV consists of one 125 MVA transformer and one 150 MVA 220/66 kV transformer and is the main source of supply for over 77,745 customers in Terang and the surrounding area. The terminal station supply area includes Terang, Colac, Camperdown, Cobden, Warrnambool, Koroit, Portland and Hamilton.

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

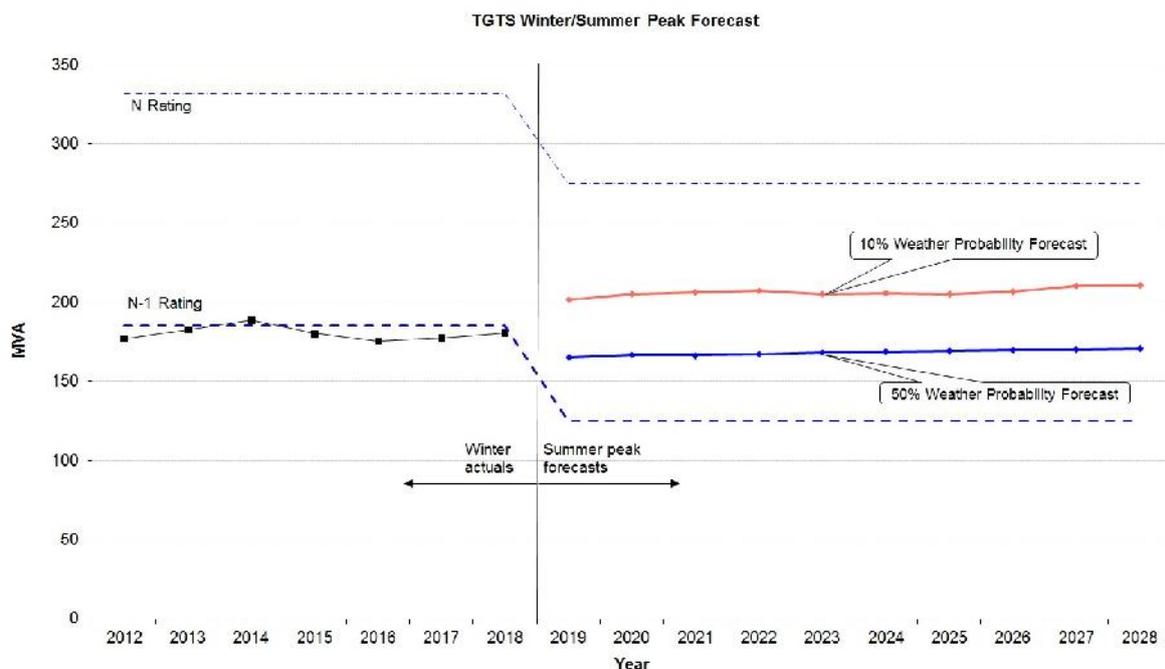
There is now 131 MW of wind generation capacity connected to the 66 kV network supplied from TGTS. The TGTS demand forecast used in this year’s report includes a forecast of wind farm generation at peak demand. As a consequence, the forecast demand at the station is now summer peaking, so the station’s summer rating of 166 MVA is used in this risk assessment. This contrasts with the approach in previous years, which applied the station’s winter rating of 185 MVA. This step change in station cyclic rating is depicted in the graph below.

TGTS 66 kV 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). Over that period, growth in winter peak demand at TGTS averaged around -0.34 MW or -0.14% per annum. The metered peak load on the station reached 180.2 MW (180.6 MVA) in winter 2017.

It is estimated that:

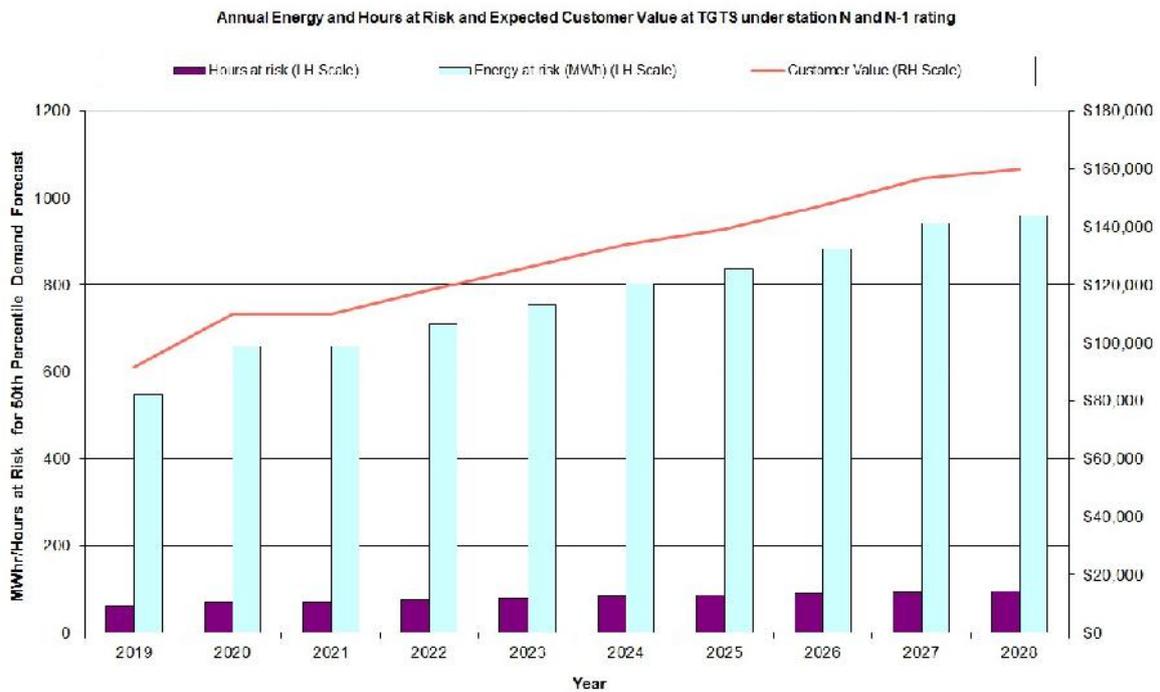
- For 3 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile forecast.
- The station load power factor at the time of peak demand is 0.99.

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



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

The bar chart below depicts the energy at risk with one transformer out of service for the 50<sup>th</sup> percentile demand forecast, and the hours per year that the 50<sup>th</sup> 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 50<sup>th</sup> percentile demand forecast.



### Comments on Energy at Risk

For an outage of one transformer at TGTS, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 95 hours in 2028. The energy at risk at the 50<sup>th</sup> percentile temperature under N-1 conditions is estimated to be 959 MWh in 2028. The estimated value to consumers of the 959 MWh of energy at risk is approximately \$37 million (based on a value of customer reliability of \$38,488 per MWh).<sup>1</sup> In other words, at the 50<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TGTS in 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$37 million.

It is emphasised however, that the probability of a major outage of one of the two transformers occurring over the year is very low at about 1.0% per transformer per annum, while the expected unavailability per transformer per annum is 0.217%. When the energy at risk (959 MWh for 2028) is weighted by this low unavailability, the expected unserved energy is estimated to be 4.2 MWh. This expected unserved energy is estimated to have a value to consumers of around \$160,000 (based on a value of customer reliability of \$38,488 per MWh).

<sup>1</sup> 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.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under 10<sup>th</sup> percentile temperature conditions, the energy at risk in 2028 is estimated to be 6,829 MWh. The estimated value to consumers of this energy at risk in 2028 is approximately \$263 million. The corresponding value of the expected unserved energy (of 29.6 MWh) is \$1.14 million.

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

	<b>MWh</b>	<b>Valued at consumer interruption cost</b>
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	959	\$37 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	4.2	\$160,000
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	6,829	\$263 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	29.6	\$1.14 million

### **Feasible options for alleviation of constraints**

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

- Replacing the #2 125 MVA 220/66 kV transformer at TGTS with a 150 MVA unit. For an indicative installation cost of \$14 million this option will most likely prove to be uneconomic as it only provides a marginal increase in station capacity, hence necessitating additional capacity augmentation shortly afterwards.
- Installation of a third 220/66 kV transformer (150 MVA) at TGTS at an indicative capital cost of \$18 million.
- Demand reduction: There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction would depend on the customer uptake and would be taken into consideration when determining the optimum timing for any future capacity augmentation.
- Embedded generation: Four existing wind farms (Codrington, Yambuk, Oaklands Hill and Mortons Lane) generate into the 66 kV infrastructure ex-TGTS with a total capacity of 131 MW. There are two committed wind farms, Salt Creek wind farm (54 MW) and Mt Gellibrand wind farm (132 MW) which will be commissioned in 2019 and contribute generation into the 66 kV infrastructure ex-TGTS. Additional wind generation is being investigated in the area supplied by TGTS and this may defer any capacity augmentation planned for TGTS.
- There are presently several large embedded generation 66 kV wind farm proposals in the area which may drive the need for an additional 150 MVA 220/66 kV transformer at TGTS to accommodate the reverse power flow expected at TGTS.

- Possible uptake of battery storage in the future could provide some contribution to supporting the peak load.

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

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

1. Install a third 220/66 kV transformer (150 MVA) at TGTS at an indicative capital cost of \$18 million. This equates to a total annual cost of approximately \$1.04 million per annum. On the basis of the medium economic growth scenario and both 50<sup>th</sup> and 10<sup>th</sup> percentile weather probability, the transformer would not be expected to be required before 2028 to support the critical peak demand.
2. As a temporary measure, maintain contingency plans to transfer load quickly to the Geelong Terminal Station (GTS) by the use of the 66 kV tie lines between TGTS and GTS in the event of an unplanned outage of one transformer at TGTS under critical loading conditions. This load transfer is in the order of 15 MVA. Under these temporary measures, affected customers would be supplied from the 66 kV tie line infrastructure on a radial network, thereby reducing their level of reliability.
3. Subject to the availability of an AusNet Transmission Group's spare 220/66 kV transformer for rural areas (refer Section 5.5), this spare transformer can be used to temporarily replace a failed transformer to minimise the transformer outage period.

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

## TGTS Terminal Station

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

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

**MVA**  
 Normal cyclic rating with all plant in service 332 via 2 transformers (summer)  
 Summer N-1 Station Rating: 166 [See Note 1 below for interpretation of N-1]  
 Winter N-1 Station Rating: 185

Station: TGTS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	164.9	166.7	166.3	167.2	168.1	168.4	169.3	169.5	170.4	170.7
50th percentile Winter Maximum Demand (MVA)	146.0	148.3	149.2	149.8	150.2	151.7	151.5	152.8	153.3	153.4
10th percentile Summer Maximum Demand (MVA)	201.4	205.2	206.3	206.9	205.0	205.7	204.9	206.6	210.0	210.8
10th percentile Winter Maximum Demand (MVA)	170.2	172.6	172.9	173.9	175.5	176.8	175.0	176.6	178.2	177.0
N-1 energy at risk at 50% percentile demand (MWh)	548.1	658.3	658.8	708.5	755.9	803.5	835.5	883.1	940.2	959.2
N-1 hours at risk at 50th percentile demand (hours)	61.5	70.8	71.5	75.3	79.5	84.0	85.8	89.8	93.3	94.8
N-1 energy at risk at 10% percentile demand (MWh)	4644.9	5429.9	5639.1	5830.6	5662.4	5907.9	5581.2	6031.6	6804.1	6829.3
N-1 hours at risk at 10th percentile demand (hours)	298.8	338.5	349.5	359.5	353.8	367.8	349.0	374.3	410.5	410.3
Expected Unserved Energy at 50th percentile demand (MWh)	2.38	2.85	2.85	3.07	3.28	3.48	3.62	3.83	4.07	4.16
Expected Unserved Energy at 10th percentile demand (MWh)	20.13	23.53	24.44	25.27	24.54	25.60	24.19	26.14	29.48	29.59
Expected Unserved Energy value at 50th percentile demand	\$0.09M	\$0.11M	\$0.11M	\$0.12M	\$0.13M	\$0.13M	\$0.14M	\$0.15M	\$0.16M	\$0.16M
Expected Unserved Energy value at 10th percentile demand	\$0.77M	\$0.91M	\$0.94M	\$0.97M	\$0.94M	\$0.99M	\$0.93M	\$1.01M	\$1.13M	\$1.14M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$0.30M	\$0.35M	\$0.36M	\$0.37M	\$0.37M	\$0.39M	\$0.38M	\$0.40M	\$0.45M	\$0.45M

#### Notes:

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

## THOMASTOWN TERMINAL STATION 66 kV (TTS 66 kV)

Thomastown Terminal Station (TTS) is located in the north of greater Melbourne. It operates at 220/66 kV and supplies Jemena Electricity Networks and AusNet Electricity Services customers in the Thomastown, Coburg, Preston, Watsonia, North Heidelberg, Lalor, Coolaroo and Broadmeadows areas.

### Background

TTS has five 150 MVA transformers and is a summer critical station. Under system normal conditions, the No.1 & No.2 transformers are operated in parallel as one group (TTS(B12)) and supply the No.1 & No.2 66 kV buses. The No.3, No.4 & No.5 transformers are operated in parallel as a separate group (TTS(B34)) and supply the No.3 & No.4 66 kV buses. The 66 kV bus 2-3 and bus 1-4 tie circuit breakers are operated open to limit the maximum prospective fault levels on the four 66 kV busses to within the switchgear ratings.

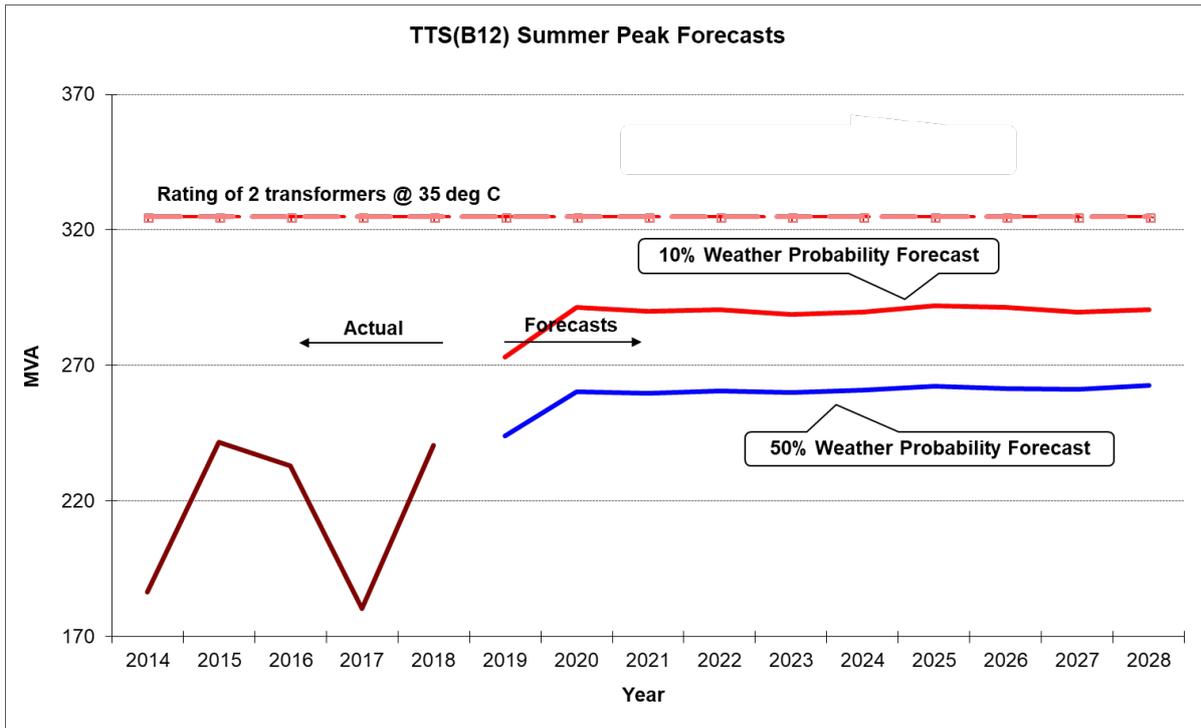
For an unplanned transformer outage in the TTS(B12) group, the No.5 transformer will automatically change over to the TTS(B12) group. Therefore, an unplanned transformer outage of any one of the five transformers at TTS will result in both the TTS(B12) & TTS(B34) groups being comprised of two transformers each. Given this configuration, load demand on the TTS(B12) group must be kept within the capabilities of the two transformers at all times or load shedding may occur.

### Transformer group TTS (B12) Summer Peak Forecasts

The graph below depicts the summer maximum demand forecasts (for 50<sup>th</sup> and 10<sup>th</sup> percentile temperatures) for TTS (B12) and the corresponding rating with both transformers (B1 & B2) operating. It is estimated that:

- For 7 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at the time of peak demand is 0.96.

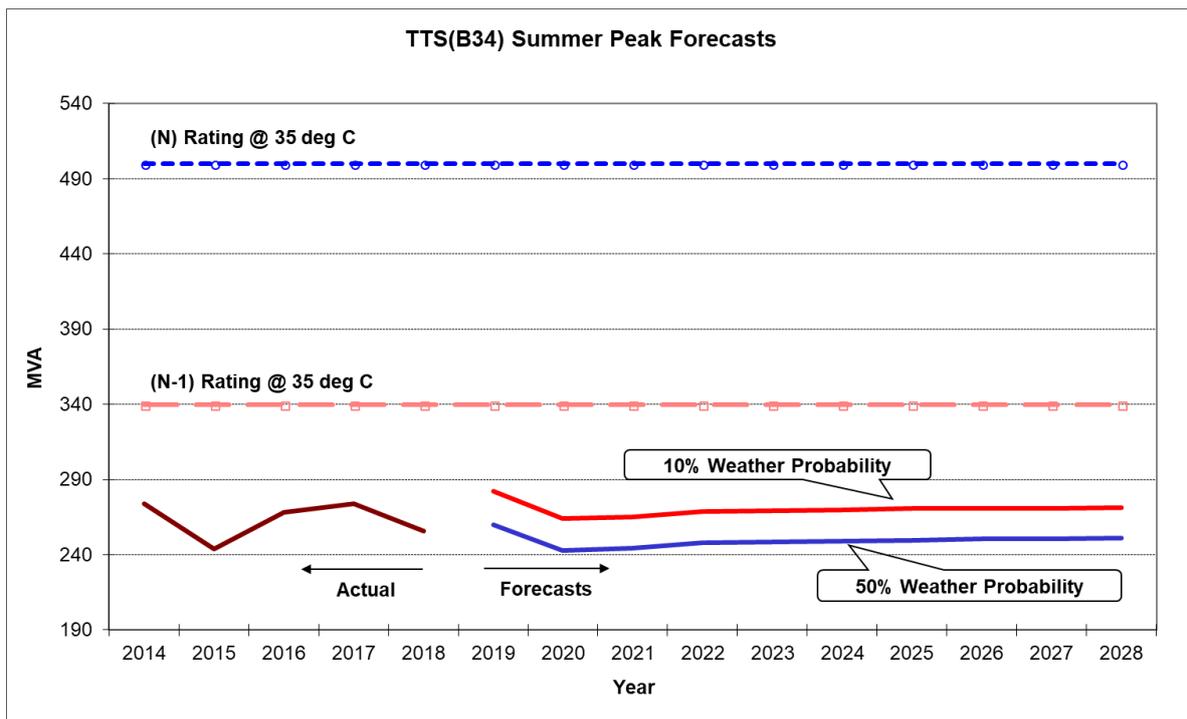
The graph shows that with all transformers in service, there is adequate capacity to meet the anticipated maximum load demand for the entire forecast period. As explained above, if an unplanned transformer outage in the TTS(B12) group occurs, the No.5 transformer will automatically change over to the TTS(B12) group. In effect then, the N-1 and N ratings of the TTS(B12) group are equivalent. Thus there is sufficient capacity provided by the TTS(B12) group to meet the anticipated maximum demand for the entire forecast period, even under a transformer outage condition.



**Transformer group TTS (B34) Summer Peak Forecasts**

The graph below depicts the TTS (B34) rating with all transformers (B3, B4 & B5) in service (“N” rating), and with one of the three transformers out of service (“N-1” rating), along with the 50<sup>th</sup> and 10<sup>th</sup> percentile summer maximum demand forecasts. It is estimated that:

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



The above graph shows that there is adequate capacity to meet the anticipated maximum load demand for the entire forecast period.

Hence, the need for augmentation of transmission connection assets at TTS 66 kV is not expected to arise over the next ten years.

The two tables on the following pages provide more detailed data on the station rating and demand forecasts.

**THOMASTOWN TERMINAL STATION (B12 TRANSFORMER GROUP)****Detailed data: Magnitude and probability of loss of load**

Distribution Businesses supplied by this station: JEN (43%), AusNet Electricity Services (57%)  
 Normal cyclic rating with all plant in service: 325 MVA (Summer peaking)  
 Summer N-1 Station Rating: 325 MVA [See note 1 below for interpretation on N-1]  
 Winter N-1 Station Rating: 356 MVA

Station: TTS (B12)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50 <sup>th</sup> percentile Summer Maximum Demand (MVA)	244	260	260	261	260	261	262	261	261	263
50 <sup>th</sup> percentile Winter Maximum Demand (MVA)	184	199	201	203	203	205	207	207	208	208
10 <sup>th</sup> percentile Summer Maximum Demand (MVA)	273	291	290	291	289	290	292	291	290	291
10 <sup>th</sup> percentile Winter Maximum Demand (MVA)	190	206	208	210	210	212	213	213	214	215
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	\$ - M									
Expected Unserved Energy value at 10th percentile demand	\$ - M									
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$ - M									

## Notes:

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

**THOMASTOWN TERMINAL STATION (B34 TRANSFORMER GROUP)****Detailed data: Magnitude and probability of loss of load**

<b>Distribution Businesses supplied by this station:</b>	JEN (100%), AusNet Electricity Services (0%)
<b>Normal cyclic rating with all plant in service:</b>	500 MVA (Summer peaking)
<b>Summer N-1 Station Rating:</b>	340 MVA [See note 1 below for interpretation on N-1]
<b>Winter N-1 Station Rating:</b>	397 MVA

<b>Station: TTS (B34)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>
50 <sup>th</sup> percentile Summer Maximum Demand (MVA)	260	243	245	248	249	249	250	250	251	251
50 <sup>th</sup> percentile Winter Maximum Demand (MVA)	221	205	208	211	213	214	214	215	215	216
10 <sup>th</sup> percentile Summer Maximum Demand (MVA)	282	264	265	269	269	270	271	271	271	271
10 <sup>th</sup> percentile Winter Maximum Demand (MVA)	225	209	212	215	216	218	218	218	219	219
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	\$ - M									
Expected Unserved Energy value at 10th percentile demand	\$ - M									
Expected Unserved Energy value using AEMO weighting of 0.7 x 50th percentile value + 0.3 x 10th percentile value	\$ - M									

**Notes:**

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

## TYABB TERMINAL STATION (TBTS)

TBTS consists of three 150 MVA 220/66 kV transformers, and is the main source of supply for over 115,000 customers on the Mornington Peninsula. The geographic coverage of the area spans from Frankston South in the north to Portsea in the south.

TBTS 66 kV is a summer critical station. Summer peak demand at TBTS generally occurs on days of high ambient temperature during the summer holiday period (from mid-December to the end of January). Given the peak demand at TBTS is directly related to air-conditioning use during the 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 reached 302.8 MW (313 MVA) in summer 2017-18, which was 33.3 MW higher than the 2016-17 maximum demand. The 2017-18 summer exceeded the previous historic peak demand of 283.4 MW (298.0 MVA) recorded on 29 January 2009. There are two embedded generation units over 1 MW connected at TBTS and 11 generation units providing 11 MW network support for the lower Mornington Peninsula sub-transmission constraints.<sup>1</sup>

Due to increasing risk at TBTS, a Regulatory Test was undertaken in 2011, which identified the installation of a third 150 MVA 220/66 kV transformer as the most economic network solution. A new third transformer was installed at TBTS and commissioned in November 2013 as shown in the graph below.

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

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

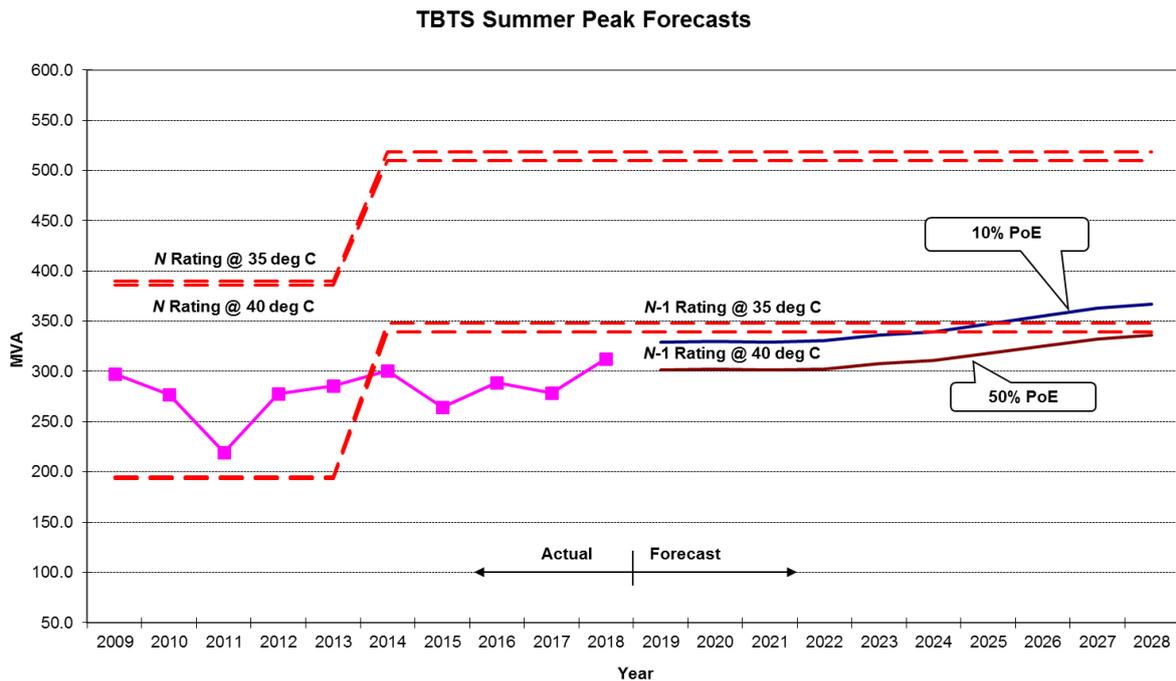
The N rating on the chart below indicates the maximum load that can be supplied from TBTS with all transformers in service. Exceeding this level will initiate AusNet Transmission Group's automatic load shedding scheme.

The graph indicates that the demand at TBTS remains below its N rating within the 10 year planning period. However, the 10<sup>th</sup> percentile summer maximum demand is forecast to exceed the station's (N-1) rating at 40°C from summer 2025. The 50<sup>th</sup> percentile summer maximum demand is expected to remain within the (N-1) rating for the entire planning period.

The station load is forecast to have a power factor of 0.968 at times of peak demand. The demand at TBTS is expected to exceed 95% of peak demand for approximately 5 hours per annum.

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<sup>1</sup> The maximum demand forecasts adopted in this risk analysis exclude the impact of generation schemes.



### Comments on Energy at Risk

The graph above indicates that for an outage of one transformer at TBTS, it is expected that there would be sufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature over the ten year forecast period.

However, for an outage of one transformer at TBTS, it is expected that from summer 2025, there would be insufficient capacity at the station to supply all demand at the 10<sup>th</sup> percentile temperature. By the end of the ten-year planning period in 2028, the energy at risk under N-1 conditions is 69 MWh at the 10<sup>th</sup> percentile demand forecast. Under these conditions, there would be insufficient capacity to meet demand for 4 hours in that year. The estimated value to customers of the 69 MWh of energy at risk in 2028 is approximately \$2.4 million (based on a value of customer reliability of \$34,946/MWh)<sup>2</sup>. In other words, at the 10<sup>th</sup> percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at TBTS over the summer of 2028 would be anticipated to lead to involuntary supply interruptions that would cost consumers \$2.4 million.

Typically, the probability of a major outage of a terminal station transformer occurring over the year is very low at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (69 MWh in 2028) is weighted by this low unavailability, the expected unserved energy is estimated to be around 0.4 MWh. This expected unserved energy is estimated to have a value to consumers of around \$15,600 (based on a value of customer reliability of \$34,946/MWh).

These key statistics for the year 2028 under N-1 outage conditions are summarised in the table below.

<sup>2</sup> 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.

	MWh	Valued at consumer interruption cost
Energy at risk, at 50 <sup>th</sup> percentile demand forecast	0.0	0
Expected unserved energy at 50 <sup>th</sup> percentile demand	0.0	0
Energy at risk, at 10 <sup>th</sup> percentile demand forecast	69	\$2.4 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	0.4	\$15,600

### Feasible options for alleviation of constraints

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

Implement a contingency plan to transfer load to adjacent terminal stations. United Energy has established and implemented the necessary plans that enable load transfers under contingency conditions, via both 66 kV sub-transmission and 22 kV distribution networks. These plans are reviewed annually prior to the summer season. Transfer capability away from TBTS 66 kV onto adjacent terminal stations via the distribution network is assessed at 21 MVA for summer 2019.

Given that the 50<sup>th</sup> percentile demand forecast is expected to remain below the N-1 rating of the station, no energy will be at risk for a single transformer outage based on the current 50<sup>th</sup> percentile demand forecast for the foreseeable future. The expected unserved energy under the 10<sup>th</sup> percentile demand forecast is not significant over the ten year planning horizon. Moreover, the load at risk from summer 2025 can be managed operationally by transferring load under contingency via the distribution network.

On the basis of the current forecasts, no major demand related augmentation is planned at TBTS over the next ten years.

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

## TYABB TERMINAL STATION 66 kV

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

Distribution Businesses supplied by this station:	United Energy (100%)
Station operational rating (N elements in service):	519 MVA (Summer peaking)
Summer N-1 Station Rating:	348 MVA [See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating:	397MVA

Station: TBTS 66kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	302	302	302	303	308	311	318	326	332	336
50th percentile Winter Maximum Demand (MVA)	198	201	203	205	207	209	212	216	219	222
10th percentile Summer Maximum Demand (MVA)	329	330	329	330	336	339	348	356	363	367
10th percentile Winter Maximum Demand (MVA)	201	204	206	208	210	213	216	220	223	226
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	12	30	55	69
N-1 hours at risk at 10th percentile demand (hours)	0	0	0	0	0	0	2	3	4	4
Expected Unserved Energy at 50th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Expected Unserved Energy at 10th percentile demand (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	0.4
Expected Unserved Energy value at 50th percentile demand	\$0.0k	\$0.0k								
Expected Unserved Energy value at 10th percentile demand	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$0.0k	\$2.6k	\$6.7k	\$12.3k	\$15.6k
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	\$0.0k	\$0.0k	\$0.0k	\$0.8k	\$2.0k	\$3.7k	\$4.7k

#### Notes:

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

## WEMEN TERMINAL STATION (WETS)

Wemen Terminal Station (WETS) is a new station which was commissioned in February 2012. WETS consists of one 70 MVA 235/66 kV transformer supplying part of the 66 kV network previously supplied by RCTS. An additional 70 MVA transformer is expected to be on line by the end of 2018 increasing the N rating to 140 MVA. This configuration is the main source of supply for approximately 6,035 customers in the Wemen and Ouyen areas. The station supply area includes Wemen, Robinvale and Ouyen.

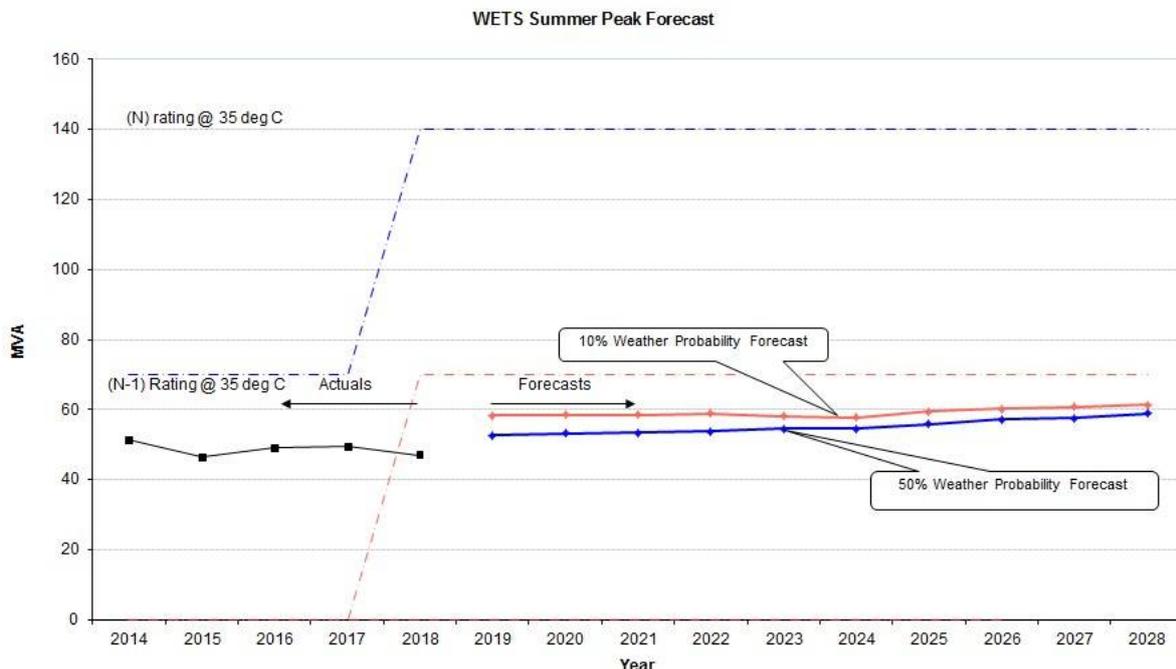
### Magnitude, probability and impact of loss of load

WETS demand is summer peaking. The peak load for the 66 kV network on the station reached 46.8 MW in summer 2018.

It is estimated that:

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

The graph below depicts the 10<sup>th</sup> and 50<sup>th</sup> percentile summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating at 35°C ambient temperature. As WETS has only one transformer the "N-1" rating is zero.



In order to mitigate the risk of generation curtailment of new solar farms in the area an additional 70 MVA transformer is being installed on the WETS 66kV system in 2018, as noted above. The transformer will be run in hard parallel (banked) with the existing 70 MVA transformer (i.e. no additional 220 kV or 66 kV circuit breakers will be installed). As a result, there will be sufficient capacity at the station to supply all expected load demand at the 50<sup>th</sup> and 10<sup>th</sup> percentile temperature, over the forecast period, even with one transformer out of service. Therefore, the need for additional augmentation or other corrective action is not expected to arise over the next ten years.

## 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 10,112 customers in CitiPower’s distribution network. The terminal station provides major 22 kV supply to the West Melbourne area including Melbourne Docks, Docklands Areas, North Melbourne (including a railway substation), Parkville and Carlton, and the northern and western inner Central Business District and surrounding areas.

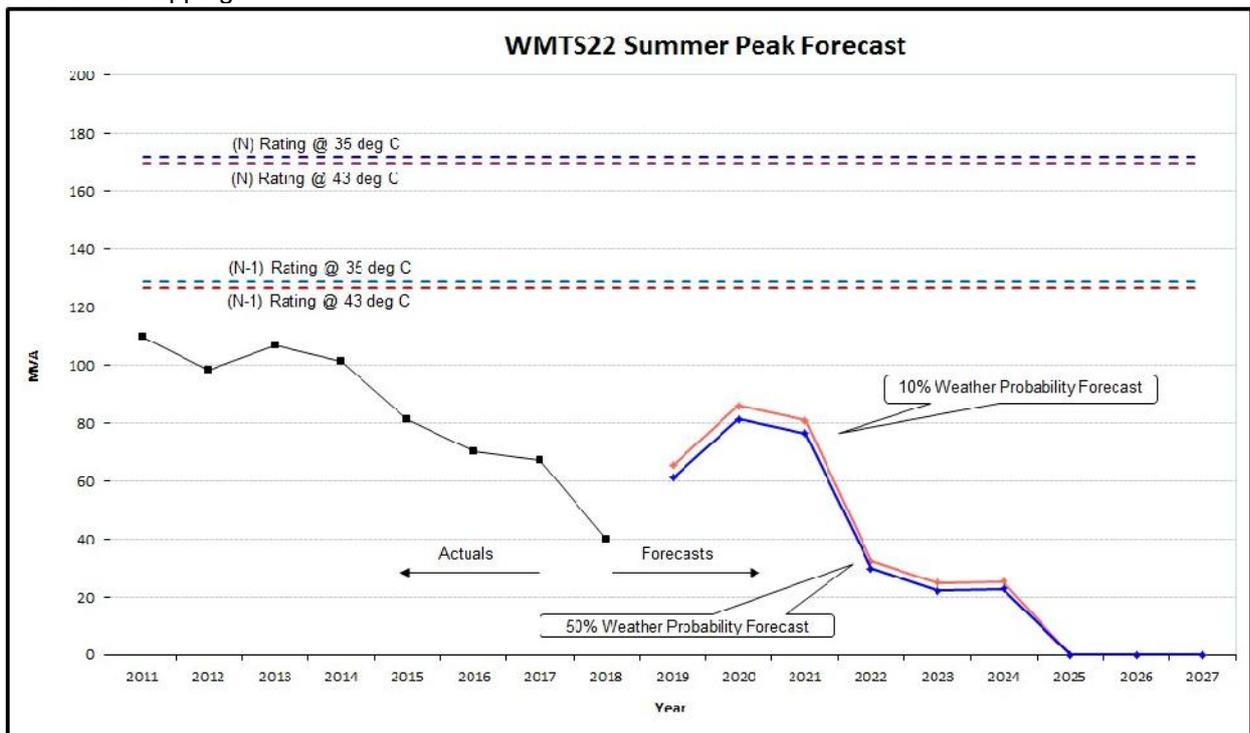
A new 66/11 kV zone substation (BQ) was established in 2011. BQ zone substation is now supplied via the newly established Brunswick Terminal Station (BTS 66 kV) and partly offloaded WMTS 22 kV over 2012 – 2014. Further offloads from WMTS 22 are planned to occur to both BTS 66 and WMTS 66 within the next 6 years. These offloads are shown in the WMTS 22 load forecast below.

The peak load on the station reached 39 MW in summer 2017/18. It is estimated that:

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

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

The graph below depicts the station’s operational N rating for all transformers in service and the N-1 rating (at 35 and 43 degrees ambient temperature), and the latest 10<sup>th</sup> and 50<sup>th</sup> 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 50<sup>th</sup> and 10<sup>th</sup> 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 66kV and BTS 66kV before 2025. As part of its asset renewal program, AusNet Transmission Group plans to retire all of the existing WMTS 22 kV systems by the end of 2021, but negotiations are currently underway to defer retirement to enable supply to be provided to a major customer until 2025.

## WEST MELBOURNE TERMINAL STATION 66 kV (WMTS 66 kV)

WMTS 66 kV is a summer critical station consisting of four 150 MVA 220/66 kV transformers. The terminal station is shared by CitiPower (57.0%) and Jemena Electricity Networks (430%). The terminal station provides major supply for 78,572 customers in the western Central Business District, including Docklands areas, as well as the inner suburbs of Northcote and Brunswick West in the north, and Kensington, Flemington, Footscray and Yarraville in the west.

WMTS 66 kV is operating with one of the four transformers on “Normal Open Auto-close” duty (i.e. on hot stand-by with a facility for automatic closing upon forced outage of any one of the three normal-running transformers). This arrangement facilitates control of the 66 kV fault level to within the terminal station fault level rating. With this transformer operating arrangement, the N rating will be approximately equal to the N-1 rating (i.e. equal to the capacity of three transformers), thus imposing a restriction that the terminal station should not be loaded beyond the N-1 rating at any time.

Following the extremely hot summer in 2009, AusNet Transmission Group expressed concern regarding the operating temperature of the WMTS 220/66 kV transformers. In order to avoid operating the WMTS transformers at temperatures that would result in accelerated aging, AusNet Transmission Group has reduced the WMTS Terminal Station summer cyclic ratings by about 5.5% to 497 MVA at 35°C ambient temperature and about 10% to 463 MVA at 43°C ambient temperature. As part of its asset renewal program, AusNet Transmission Group plans to replace all four existing 150 MVA 220/66 kV transformer units (B1, B2, B3 and B4) with three 225 MVA transformer units by the end of 2021.

The peak load on the station reached 301.9 MW (308 MVA) in summer (January) 2018, after zone substations VM, WA and BQ were transferred to Brunswick Terminal Station (BTS 66) in December 2016.

It is estimated that:

- For 20 hours per year, 95% of peak demand is expected to be reached under the 50<sup>th</sup> percentile demand forecast.
- The station load power factor at time of peak demand is 0.98.

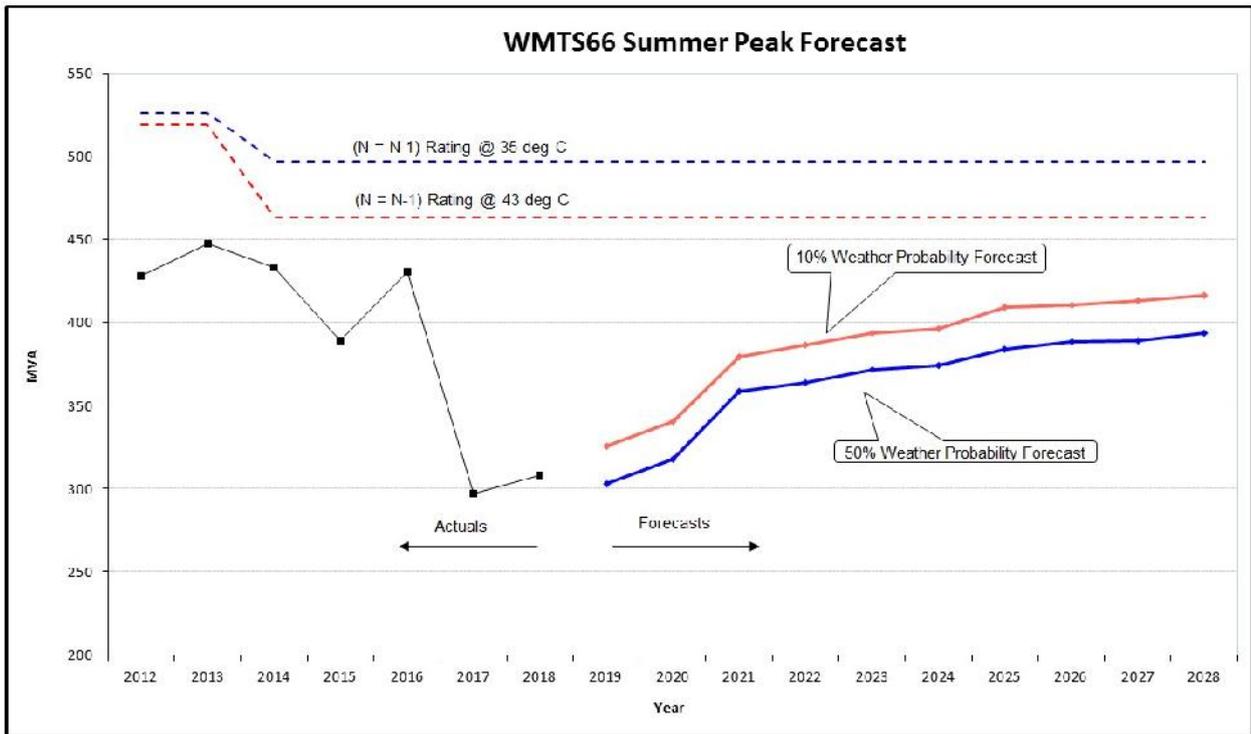
### Magnitude, probability and impact of loss of load

The graph below depicts the station’s N-1 rating (approximately equal to the N rating) at 35°C and 43°C, and the latest 10<sup>th</sup> and 50<sup>th</sup> percentile maximum demand forecasts during the summer periods over the next ten years. The forecast demands include the effects of load transfer works<sup>1</sup> which were undertaken after the establishment of BTS 66 kV in late 2016. It also includes the further offloads<sup>2</sup> from WMTS 22 to WMTS 66 between 2019 and 2021 prior to the planned decommissioning of the 22 kV supply from WMTS.

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<sup>1</sup> WA (52.7 MW), BQ (49.2 MW) and VM (42.0 MW) transfer from WMTS 66 to BTS 66 in late 2016.

<sup>2</sup> J (6.6 MW) transfer from WMTS 22 to WMTS 66 in 2019, VR (9.2 MW) and DA (23 MW) transfer from WMTS 22 to WMTS 66 in 2021.



The graph shows that there is sufficient capacity at WMTS 66 kV to supply the forecast 10<sup>th</sup> percentile and 50<sup>th</sup> percentile demand over the planning period, even with one transformer out of service. Therefore, the need for augmentation or other corrective action is not expected to arise over the next ten years.

## WODONGA TERMINAL STATION (WOTS 66 kV and 22 kV)

Wodonga Terminal Station is the main source of supply for a significant part of north-eastern Victoria. The supply is via two 330/66/22 kV three-winding transformers with a nominal rating of 75 MVA each.

This terminal station supplies Wodonga centrally as well as the area from Rutherglen in the west to Corryong in the east. The Hume Power Station (HPS) is connected to the WOTS 66 kV bus and can supply up to 58 MVA into the WOTS 66 kV bus, offsetting the load on the transformers.

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

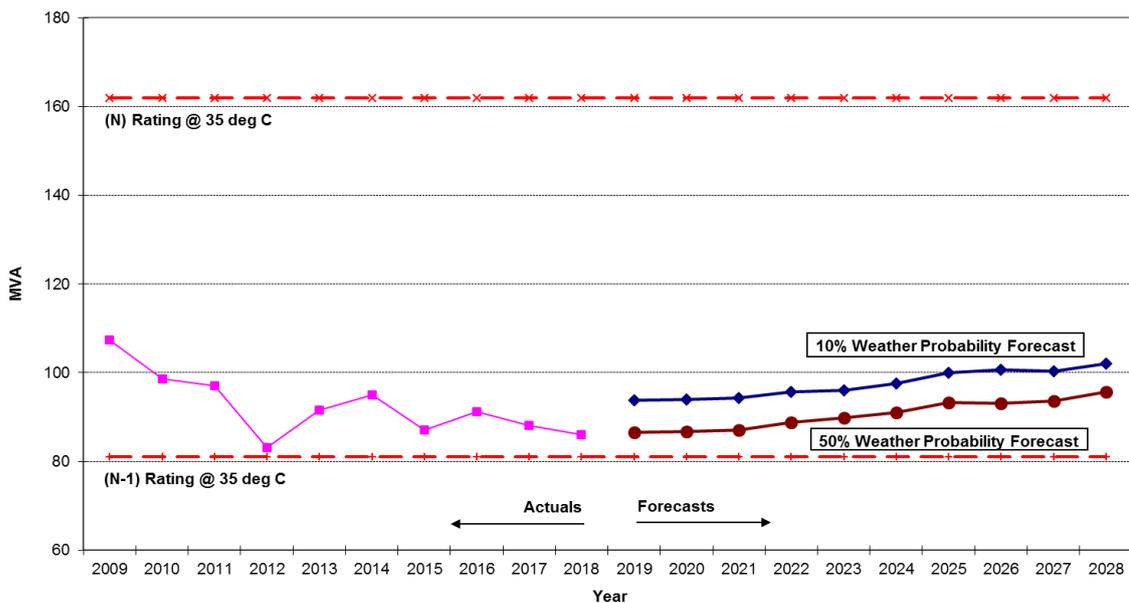
### Magnitude, probability and impact of loss of load

WOTS is a summer peaking station and the combined 66 kV and 22 kV summer peak demand is forecast to decline on average by 0.5% per annum 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 peak load on the station reached 92.8 MW (95 MVA) in summer 2013/14. The recorded peak demand in summer 2017/18 was 84.4 MW (86.0 MVA), which was lower than the 2013/14 station peak. The demand at WOTS 66 kV and 22 kV is expected to exceed 95% of the 50<sup>th</sup> percentile peak demand for 4 hours per annum. The station load has a power factor of 0.98 at maximum demand but load on the transformers has a power factor of 0.99 due to 22 kV capacitor banks installed at the station.

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

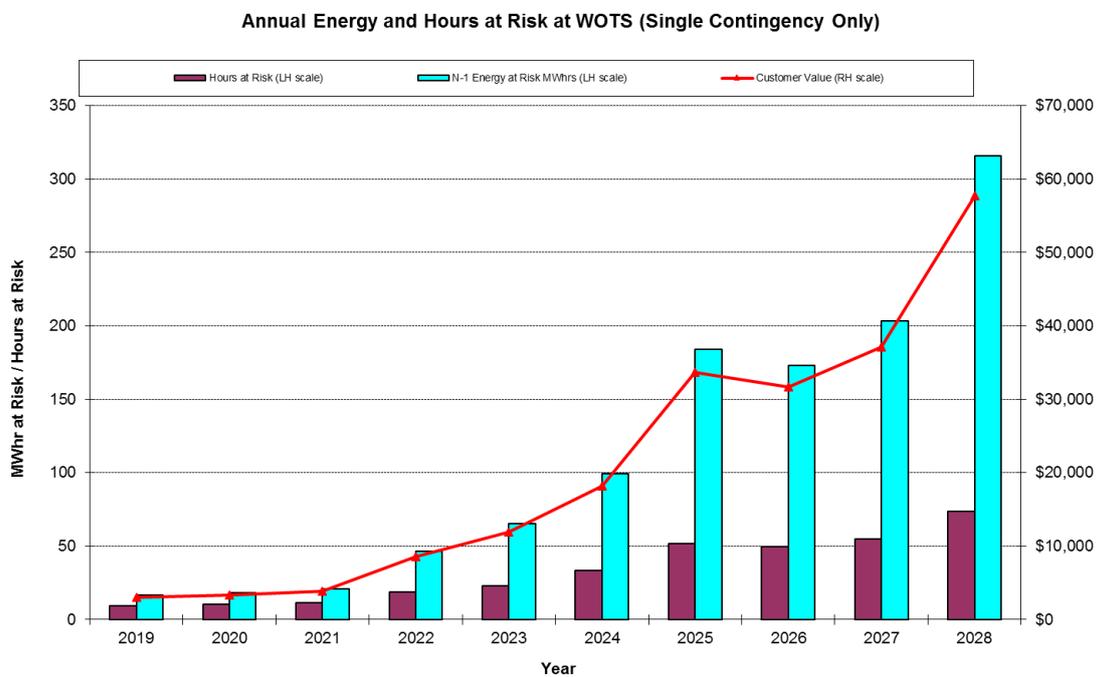
WOTS 66 kV and 22 kV combined Summer Peak Demand Forecasts



The combined 66 kV and 22 kV load at WOTS is not expected to reach the “N” summer station rating within the 10 year planning horizon, but it presently exceeds the “N-1” rating at the 50<sup>th</sup> and 10<sup>th</sup> percentile summer demand level, and is forecast to continue to do so with an increasing trend. Demand on the individual 66 kV and 22 kV windings is well within the ratings of the individual windings.

The combined 66 kV and 22 kV winter maximum demand at WOTS is less than the summer maximum demand and the station winter rating is higher than the summer rating. Forecast 50<sup>th</sup> and 10<sup>th</sup> percentile winter demand at WOTS 66 kV and 22 kV is not expected to exceed the “N -1” winter station rating in the next ten years.

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



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

For a major outage of any one of the two 330/66/22 kV transformers at WOTS over the entire summer period, and assuming that Hume Power Station is unavailable, there will be insufficient capacity at the station to supply all demand at the 50<sup>th</sup> percentile temperature for about 9 hours in 2018/19, increasing to about 73 hours in summer 2027/28. The energy at risk under “N-1” conditions is forecast to increase from 17 MWh in 2018/19 to 316 MWh in summer 2027/28. The estimated value to consumers of the energy at risk in 2027/28 is approximately \$13.3 million (based on a value of customer reliability of \$42,199/MWh at WOTS)<sup>1</sup>.

<sup>1</sup> 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.

However the probability of a major outage of one of the two transformers occurring over the year is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (316 MWh for summer 2027/28) is weighted by this low unavailability, the expected unserved energy is estimated to be around 1.4 MWh. The corresponding value of expected unserved energy is approximately \$59,000.

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of average (50<sup>th</sup> percentile) summer temperatures occurring in each year. Under higher (10<sup>th</sup> percentile) summer temperature conditions, the energy at risk in 2027/28 is estimated to be 1,284 MWh. The estimated value to consumers of the energy at risk in 2027/28 is approximately \$54.2 million. The corresponding expected unserved energy at the 10<sup>th</sup> percentile demand forecast is 5.6 MWh, which has an estimated value to consumers of approximately \$0.23 million.

The key statistics for the year 2027/28 under “N-1” outage conditions are summarised in the table below.

	MWh	Valued at consumer interruption cost
Energy at risk at 50 <sup>th</sup> percentile demand forecast	316	\$13.3 million
Expected unserved energy at 50 <sup>th</sup> percentile demand	1.4	\$59,000
Energy at risk at 10 <sup>th</sup> percentile demand forecast	1,284	\$54.2 million
Expected unserved energy at 10 <sup>th</sup> percentile demand	5.6	\$0.23 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 rating is exceeded, then the Overload Shedding Scheme for Connection Assets (OSSCA) which is enabled by AusNet Transmission Group’s TOC<sup>2</sup> to protect the connection assets from overloading<sup>3</sup>, will act swiftly to reduce the loads in blocks to within safe loading limits. If OSSCA operation does occur, any load reductions that are in excess of the amount required to limit load to the rated capability of the station would be restored at zone substation feeder level in accordance with AusNet Electricity Services’ operational procedures after the operation of the OSSCA scheme.

### Comments on Energy at Risk - Assuming HPS generation is available

The previous comments on energy at risk are based on the assumption that there is no embedded generation available to offset the 330/66/22 kV transformer loading.

However, the generation from Hume Power Station (HPS) can be fed into the WOTS 66 kV bus. The power station is capable of generating up to 58 MVA. This generation can also be connected to the TransGrid 132 kV Network in New South Wales. The generation from HPS is dependent on water releases from Hume Dam for irrigation and the water level in the dam can vary widely from year to year. There is presently no guarantee that generation from HPS will be available to offset transformer loading at

<sup>2</sup> Transmission Operation Centre.

<sup>3</sup> 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.

WOTS. With HPS generating to its full capacity there would be no energy at risk at WOTS over the ten year planning horizon for the 50<sup>th</sup> or 10<sup>th</sup> percentile summer maximum demand forecasts.

### **Feasible options for alleviation of constraints**

The demand at WOTS has remained relatively flat in recent years, but is forecast grow slightly over the 10 year planning horizon. With the movement in forecast maximum demand, it is important to monitor the actual demand at WOTS going forward, and to take appropriate action to manage the risk at the lowest cost to consumers.

The following are potentially feasible options for addressing constraints at this station.

#### **1. Load transfers**

Only 1 MVA of load can be shifted away from WOTS using the existing distribution network, so this option has limited ability to manage the risk at WOTS in the near future.

#### **2. Addition of Power Factor Correction Capacitors**

The station is currently running with a power factor of around 0.99 at summer peak. At this power factor the use of additional capacitor banks to reduce the MVA loading would only provide marginal benefits.

#### **3. Demand reduction**

Over sixty percent of the peak demand is from Commercial and Industrial customers and AusNet Electricity Services will be looking into demand management through either special tariff incentives, or a demand management aggregator to assess these alternatives to network augmentation.

#### **4. Embedded generation**

As discussed above, subject to available water HPS can provide up to 58 MVA of network support to WOTS.

#### **5. Fine tuning OSSCA**

OSSCA scheme settings are reviewed annually so as to minimise the impact on customers of any load shedding that may take place to protect the connection assets from overloading.

It is noted that the two 330/66/22 kV transformers at WOTS are the only two of this voltage ratio in Victoria. AusNet Transmission Group does not have a spare transformer suitable for use at WOTS, so it is expected that it would take approximately 12 months to replace a failed transformer at WOTS.

### **Preferred network option for alleviation of constraints**

In view of the current and forecast level of expected unserved energy at WOTS, implementation of a network solution is unlikely to be economic 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 assuming embedded generation is not available.

**WODONGA TERMINAL STATION 66kV and 22kV Loading (WOTS)**  
**Detailed data: Magnitude and probability of loss of load**

Distribution Businesses supplied by this station:

AusNet Electricity Services (100%)

Normal cyclic rating with all plant in service

162 MVA via 2 transformers (Summer peaking)

Summer N-1 Station Rating

81 MVA [See Note 1 below for interpretation of N-1]

Winter N-1 Station Rating

87 MVA

Station: WOTS 66kV & 22kV	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
50th percentile Summer Maximum Demand (MVA)	86.6	86.8	87.0	88.8	89.8	91.1	93.3	93.1	93.7	95.7
50th percentile Winter Maximum Demand (MVA)	70.1	70.8	72.0	73.7	74.1	75.2	76.5	76.8	77.6	78.5
10th percentile Summer Maximum Demand (MVA)	93.8	93.9	94.2	95.7	96.1	97.7	100.0	100.6	100.3	102.1
10th percentile Winter Maximum Demand (MVA)	72.1	72.8	74.0	75.7	76.2	77.1	78.4	78.8	79.5	80.5
N - 1 energy at risk at 50th percentile demand (MWh)	17	18	21	47	65	99	184	173	203	316
N - 1 hours at risk at 50th percentile demand (hours)	9	10	11	19	23	33	51	50	55	73
N - 1 energy at risk at 10th percentile demand (MWh)	356	362	391	518	558	719	996	1,079	1,046	1,284
N - 1 hours at risk at 10th percentile demand (hours)	85	86	90	105	109	125	147	153	151	169
Expected Unserved Energy at 50th percentile demand (MWh)	0.1	0.1	0.1	0.2	0.3	0.4	0.8	0.8	0.9	1.4
Expected Unserved Energy at 10th percentile demand (MWh)	1.5	1.6	1.7	2.2	2.4	3.1	4.3	4.7	4.5	5.6
Expected Unserved Energy value at 50th percentile demand	\$0.00M	\$0.00M	\$0.00M	\$0.01M	\$0.01M	\$0.02M	\$0.03M	\$0.03M	\$0.04M	\$0.06M
Expected Unserved Energy value at 10th percentile demand	\$0.07M	\$0.07M	\$0.07M	\$0.09M	\$0.10M	\$0.13M	\$0.18M	\$0.20M	\$0.19M	\$0.23M
Expected Unserved Energy value using AEMO weighting of 0.7 X 50th percentile value + 0.3 X 10th percentile value	\$0.02M	\$0.02M	\$0.02M	\$0.03M	\$0.04M	\$0.05M	\$0.08M	\$0.08M	\$0.08M	\$0.11M

Notes:

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