Victorian Annual Planning Report

June 2019

Electricity transmission planning for Victoria

Important notice

PURPOSE

The purpose of this publication is to provide information relating to electricity supply, demand, network capability, and development for Victoria's electricity transmission declared shared network.

AEMO publishes the Victorian Annual Planning Report (VAPR) in accordance with clause 5.12 of the National Electricity Rules. This publication is based on information available to AEMO as at April 2019, although AEMO has incorporated more recent information where practical.

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VERSION CONTROL

Version	Release date	Changes
1	28/06/2019	Initial release

Executive summary

The Australian Energy Market Operator (AEMO) is responsible for planning and directing augmentation on the Victorian electricity transmission Declared Shared Network (DSN). The *Victorian Annual Planning Report* (VAPR) assesses the adequacy of the DSN to meet reliability and security needs over the coming 10 years.

The VAPR sits alongside AEMO's *Integrated System Plan* (ISP) as a key component in the national regulatory framework that aims to deliver efficient planning and economic investment. The VAPR leverages the nationally-optimised investment plans developed in the ISP, and overlays more detailed information about local congestion issues and regional performance characteristics.

The regional VAPR studies provide insights relating to security of supply, reliability, network capability, system performance, and emerging augmentation opportunities that may deliver net market benefits.

Unprecedented change

The energy landscape in Victoria is undergoing unprecedented change. Strong investor interest in western parts of the state is shifting the geographic diversity of supply sources away from the Latrobe Valley, while increasing penetration of non-synchronous generation is further changing the technical characteristics of the system. Overlaid on this, consumer response through distributed energy resources (DER) is impacting the very nature of demand and raising new challenges in operating the transmission network.

For the first time, in 2018-19, minimum demand in Victoria occurred in the early afternoon rather than overnight. This represents a key transition point in the penetration of rooftop photovoltaic (PV) and other DER technologies. In addition, parts of the system that have historically been net loads are now behaving increasingly as net generation sources – changing system dynamics at a fundamental level.

Managing secure operating voltages at times of minimum demand has also remained a high priority, as falling operational demand continues to place pressure on the system's reactive power capabilities.

While the Victorian DSN remained secure under normal operating conditions, tightening supply margins and record-breaking high temperatures contributed to limited periods of supply shortfall in January 2019. To maintain power system reliability during these periods, AEMO was forced to activate the Reliability and Emergency Reserve Trader (RERT) and to maintain power system security, AEMO was forced to implement load shedding strategies.

Significant investment

In response to these rapid system changes, and consistent with recommendations in the 2018 ISP, significant new network investment projects are being progressed through the regulatory process. The projects together aim to:

- Deliver higher utilisation of existing generation sources in the west of Victoria.
- Unlock additional high-quality renewable energy zones (REZs).
- Manage voltage control challenges.
- Ensure continued supply reliability as traditional coal generation sources withdraw from the NEM.
- Ultimately, minimise system cost to achieve the most efficient outcomes for consumers.

AEMO is also continuing to monitor the emergence of new limits, particularly those that may only become significant following an unexpected change in local demand, generator investment, or generator withdrawal.

While no newly identified limitations have triggered a formal economic assessment since the 2018 VAPR, several new limits have been put on heightened monitoring. These include post-fault voltage oscillation risks in the north-west of Victoria, and diminishing levels of system strength at key nodes across the state.

As a prudent risk mitigation strategy, AEMO has also commenced preliminary studies on options to improve interconnection with New South Wales in the long term, unlocking additional renewables in Victoria and delivering reliability benefits in the event of future plant closures or declining availability in the Latrobe Valley. AEMO expects to build on these studies to commence a formal RIT-T process in the near future.

Shifting asset utilisation

While a strong focus on network augmentation is required, efficient maintenance of Victoria's existing network asset base also remains critical. In 2019, AEMO has again worked closely with AusNet Services to assess the need and economic justification for the replacement, refurbishment, derating, or retirement of assets that are approaching end-of-life.

For the first time, AEMO has also included a sensitivity analysis on the potential asset replacement impact of future generation plant withdrawals in the Latrobe Valley. This is important because, although the traditional focus of network planning has been to support growing consumer demand, further large-scale generation plant withdrawals from the Latrobe Valley may reduce the utilisation of existing network assets, or open opportunities for new local generation and interconnection projects. These changes will greatly impact the economic signals that underpin network asset replacements.

Exponential growth in renewable generation connections

The network challenges associated with integrating large volumes of new renewable generation projects are being compounded by connection of these new projects in weaker parts of the network, where the highest quality renewable fuel sources are available. The transmission network in these locations was not originally designed to accommodate high volumes of generation, or to withstand the technical characteristics associated with renewable generation technology.

As a result, some areas are experiencing significant levels of network congestion, changes in marginal loss factors (MLFs), additional system strength remediation costs, and imposed stability limitations under specific system conditions.

AEMO is progressing several network development projects to address existing and emerging limitations, while also providing net benefits to consumers. However, network augmentation alone will not resolve these issues. The market, and the system, are providing locational signals that are intended to help proponents make optimal investment decisions, and to incentivise investment in areas that drive the most cost-effective outcomes for consumers.

Performance of the Victorian DSN during 2018-19

The Victorian DSN remained secure under normal operating conditions in 2018-19, despite tightening supply-demand conditions, and record-breaking high temperatures that contributed to limited periods of supply shortfall.

Notable observations are that:

- Minimum operational demand (3,484 megawatts [MW]) occurred at 1:30 pm on 28 October 2018, representing the first time that Victorian minimum demand has occurred during the afternoon rather than overnight. This highlights the impact that an increasing penetration of rooftop PV is having on the operational characteristics of the power system. Since June 2018, *daily* minimum demand in Victoria has occurred during daytime periods on 12 separate occasions.

- Several terminal stations that have historically behaved as net loads have increasingly become net generation sources due to an increase in DER (particularly rooftop PV), coupled with distribution level generator connections. For example, measurements at Kerang Terminal Station show flows onto the transmission network over 27% of the time during the last 12 months. This demonstrates that distributed generation in the area often exceeds local electricity consumption.
- Extreme weather conditions contributed to several operating incidents in 2018-19:
  - In August 2018, a network separation event occurred following a lightning strike to the Queensland to New South Wales interconnector[1]. This resulted in load shedding in Victoria, and AEMO is actioning several recommendations to improve system resilience during events of this nature.
  - On 24 and 25 January 2019, during a period of prolonged high temperatures across multiple states, high levels of consumption coupled with unplanned generator outages resulted in insufficient supply to meet Victorian demand, and AEMO was required to activate load shedding.
- At times of minimum demand, AEMO has continued to rely on operational measures to maintain secure voltage levels, including the de-energisation of major transmission lines in Victoria.
  - In response, AEMO has entered into a short-term Non-Market Ancillary Service (NMAS) agreement to maintain power system security and reliability at times of minimum demand. AEMO is currently tendering for further interim NMAS services, while a Regulatory Investment Test for Transmission (RIT-T) is progressing to deliver a long-term solution.
- While the supply-demand balance has remained tight at times of peak demand, average exports from Victoria have increased compared with 2017-18, largely due to the connection of new renewable generation in the region.

Building a resilient power system in Victoria

The energy landscape in Victoria is undergoing unprecedented change. Strong investor interest in western parts of the state is shifting the geographic diversity of supply sources away from the Latrobe Valley, while increasing penetration of non-synchronous generation is changing the technical characteristics of the system. Overlaid on this, an increasing adoption of DER is impacting the nature of demand, and raising new challenges associated with changes in flow directions and voltage control.

In response to these changes, and consistent with the 2018 VAPR and the 2018 ISP, AEMO is undertaking:

- The Western Victoria Renewable Integration RIT-T, to reduce network congestion and facilitate connection of additional generation in Western Victoria. AEMO intends to publish the Project Assessment Conclusions Report (PACR) in July 2019. A PACR presents final RIT-T analysis and makes a conclusion on the preferred option that delivers the highest net market benefit.
- The Reactive Power Support RIT-T, to deliver additional reactive support in Victoria to alleviate voltage control issues at times of low demand. A Project Assessment Draft Report (PADR) was published in June 2019, which identifies and seeks feedback on RIT-T analysis and the selection of a preferred option. The PADR identifies that 500 megavolt amperes – reactive (MVAr) of strategically placed reactive plant would deliver the highest net market benefits. Stakeholder submissions on the PADR close in August 2019.
- The Victoria to New South Wales interconnector (VNI) RIT-T, to increase power transfer capability between the states, improving utilisation of renewable generation in the southern states, and allowing improved supply sharing between regions. AEMO intends to publish a PADR in the third quarter of 2019.

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[1] AEMO, *Final Report – Queensland and South Australia system separation on 25 August 2018*, January 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

Beyond the above projects, AEMO continues to monitor the emergence of new limits – particularly those that may only become significant following an unexpected change in local demand, generator investment, or generator withdrawal.

While no newly identified network limitations have triggered a formal economic assessment since the 2018 VAPR, several new limitations have been put on heightened monitoring. In particular:

- Post-fault voltage oscillation concerns have been identified in the north-west of Victoria under prior outage conditions. AEMO is currently managing this through normal operational limits advice and maintenance scheduling processes.
- The withdrawal of further thermal plant from the Latrobe Valley may result in supply shortfalls, system strength gaps, reactive power issues, or other consequential power system impacts. While participants are expected to provide adequate notice before decommissioning, there are risks that a substantial plant failure or force majeure event could cause an early or unexpected plant retirement.

  As a prudent risk mitigation strategy, AEMO has commenced preliminary studies on options to further expand interconnection with New South Wales in the long term, unlocking additional renewables in Victoria and delivering reliability benefits in the event of future plant closures in the Latrobe Valley. AEMO expects to build on these studies to commence a formal RIT-T process in the near future.
- AEMO is undertaking detailed dynamic power system analysis studies to identify any current system strength gaps in Victoria, and those that may emerge over the coming five-year period. While no system strength gaps have yet been declared under system normal conditions, AEMO expects to publish a final report detailing investigation results by the end of 2019. AEMO, as the System Strength Service Provider for Victoria, would then act to address any declared gaps.
- AEMO is performing a review of control schemes in Victoria to ensure they remain optimally configured and fit-for-purpose as system operating conditions change.

Maintaining Victoria's transmission network

In addition to the focus on network augmentation, appropriate maintenance of Victoria's existing network asset base remains critical. In 2019, AEMO has again worked closely with AusNet Services to assess the need and economic justification for the replacement, refurbishment, derating, or retirement of assets approaching end-of-life. In the 2019 VAPR:

- AusNet Services' 2019 asset replacement and refurbishment plans are largely consistent with those presented in the 2018 VAPR.
- Several new asset replacement projects have been identified, or have now moved within the five-year detailed assessment horizon, including:
  - Circuit breaker requirements at the Moorabool terminal station associated with the local transformers and 220 kilovolt (kV) shunt reactors.
  - Circuit breaker replacement at the Rowville terminal station associated with the local Static VAr Compensator (SVC) and capacitor bank.
- For each project, AEMO has analysed future system needs and confirmed the underlying system impact that would arise if the existing asset was removed without replacement. This analysis identified a continuing system need associated with each proposed asset replacement project.
- AEMO has also included a sensitivity analysis on the potential asset replacement impact of future generation plant withdrawals in the Latrobe Valley. Although the traditional focus of network planning has been to support growing consumer demand, further large-scale generation plant withdrawals from the Latrobe Valley may reduce the utilisation of existing network assets, or open opportunities for new local generation and interconnection projects. These changes will greatly impact the economic signals that underpin network asset replacements.

Rapid growth in Victorian generation investment

Investment in new renewable generation in Victoria is growing at an exponential rate. There are currently 4.4 gigawatts (GW)[2] of installed renewable generating units in Victoria, a further 2.4 GW of renewable projects have committed to connect, and an additional 8 GW of renewables are proposed to connect[3]. This trend has been driven by the decline in renewable technology costs and supported by renewable policies, notably the Victorian Government's plan to deliver 50% renewable energy generation by 2030 under the Victorian Renewable Energy Target (VRET)[4].

This rapid surge in renewable generator connections is driving a fundamental change in the behaviour of the Victorian power system, as the generation fleet transitions from traditional synchronous generation (coal and gas) to variable non-synchronous generation (wind and solar).

Areas of interest for the quality of their renewable fuel sources (such as north-west Victoria) are often parts of the network that have not been designed to accommodate large volumes of generation. Some renewable generator technologies are also not robust enough to withstand the technical characteristics associated with these weak network areas.

Locational signals are integrated in the NEM design, and are intended to guide developers to invest in areas that promote the most cost-effective outcome for consumers. Some investors in Victoria are already facing economic impacts and technical challenges associated with connection to a weak transmission network, including:

- Thermal limitations – high volumes of renewable generation in the west of the state are leading to significant network congestion, resulting in the constraint of generator outputs.
- Stability limitations – the technical characteristics of wind and solar generation can contribute to reduced network stability, such as the identified risk if undamped voltage oscillations in Western Victoria. Generator restrictions are necessary to mitigate the risk of system interruptions or collapse in the region.
- Diminishing system strength – as new renewable generators connect to weak areas of the network, these generators face additional constraints and considerable remediation investment costs or delays.
- Diminishing MLFs – increased power flows from renewable generators in Western Victoria to load centres is resulting in growing network losses and reduced MLFs for some generators in western parts of the state. As MLFs are applied to generator payments, lower MLFs result in reduced generator revenue.

Significant RIT-T augmentation projects are already underway to deliver reduced network congestion and unlock opportunities for more efficient use of renewable resources in Victoria. In addition, AEMO is seeking opportunities to drive cost efficiencies for consumers by supporting optimised integration of DER, energy storage devices, and other technologies.

Beyond investment in network infrastructure and market services, the growing complexity of power system requirements places additional pressure on investors to understand locational signals, technical standards, and connection processes that can have material impacts on their project timing and viability. The 2019 VAPR includes a new chapter (Chapter 6) aimed at providing investors with a better understanding of these complex issues.

[2] See Victoria update for 10 May 2019 on AEMO's Generation Information webpage, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[3] Definitions of proposed and committed generation are under the Background Information tab in each regional spreadsheet on AEMO's Generation Information webpage.

[4] For more information, see https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

Contents

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Figures

1. Introduction

The Australian Energy Market Operator (AEMO) is responsible for planning and directing augmentation on the Victorian electricity transmission Declared Shared Network (DSN).

The *Victorian Annual Planning Report* (VAPR) assesses the adequacy of the DSN to meet reliability and security needs efficiently over the next 10 years, and provides insights relating to security of supply, reliability, forecast demand, network capability, system performance, and emerging network developments that may deliver net market benefits to consumers.

AEMO publishes the VAPR as part of its role as Victorian transmission planner under the National Electricity Law (NEL), in accordance with clause 5.12 of the National Electricity Rules (NER).

In the 2019 VAPR:

- Chapter 2 reviews the performance of the DSN throughout 2018-19, including performance at times of high network stress, and is consistent with the reviews undertaken in previous VAPRs.
- Chapter 3, a new chapter in 2019, provides an update on network development opportunities identified in the 2018 VAPR, the 2018 *Integrated System Plan* (ISP), and the 2018 *National Transmission Network Development Plan* (NTNDP). This chapter highlights the alignment of the VAPR with the broader national regulatory framework, and supports work already underway to progress ISP recommended augmentations in Victoria.
- Chapter 4 assesses future DSN performance, and identifies new emerging and monitored limitations, beyond or in addition to those identified in the 2018 VAPR.
- Chapter 5 presents updated information on AusNet Services' Asset Renewal Plan, outlining expected network asset retirements, deratings, and renewals within the 10-year VAPR timeframe, including AEMO's assessment of the future network needs associated with these assets.
- Chapter 6, a new chapter in 2019, provides a range of information and resources to assist new and intending participants to better understand the changing investment landscape in Victoria, including a summary of important locational signals and challenges that may impact future investments.

The 2019 VAPR is supported by an online interactive map[5] that provides data and analysis for a range of National Electricity Market (NEM) topics, including current and emerging development opportunities, transmission connection point forecasts, and national transmission plans.

1.1 Context of the 2019 VAPR

The context for network development, both regionally and nationally, is changing rapidly – with many moving parts across the regulatory, policy, planning, investment, and operational landscape.

Key developments since publication of the 2018 VAPR are summarised below.

Changes to the national regulatory framework

AEMO is working with the Council of Australian Governments (COAG) Energy Council and the Energy Security Board (ESB) to progress changes to the national planning framework that drive towards a more actionable

[5] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards.

ISP, and that will have consequential effects on regional planning processes for transmission network service providers (TNSPs).

A key objective of the ESB's reforms is to develop a streamlined regulatory framework that allows the outputs of the ISP to be incorporated into TNSPs' investment decisions[6]. Following comprehensive system-wide modelling, the ISP identifies system needs and credible options to meet needs. The role of the Regulatory Investment Test for Transmission (RIT-T) is then to examine projects identified in the ISP and ensure that the chosen solution maximises net market benefits when compared with other possible options.

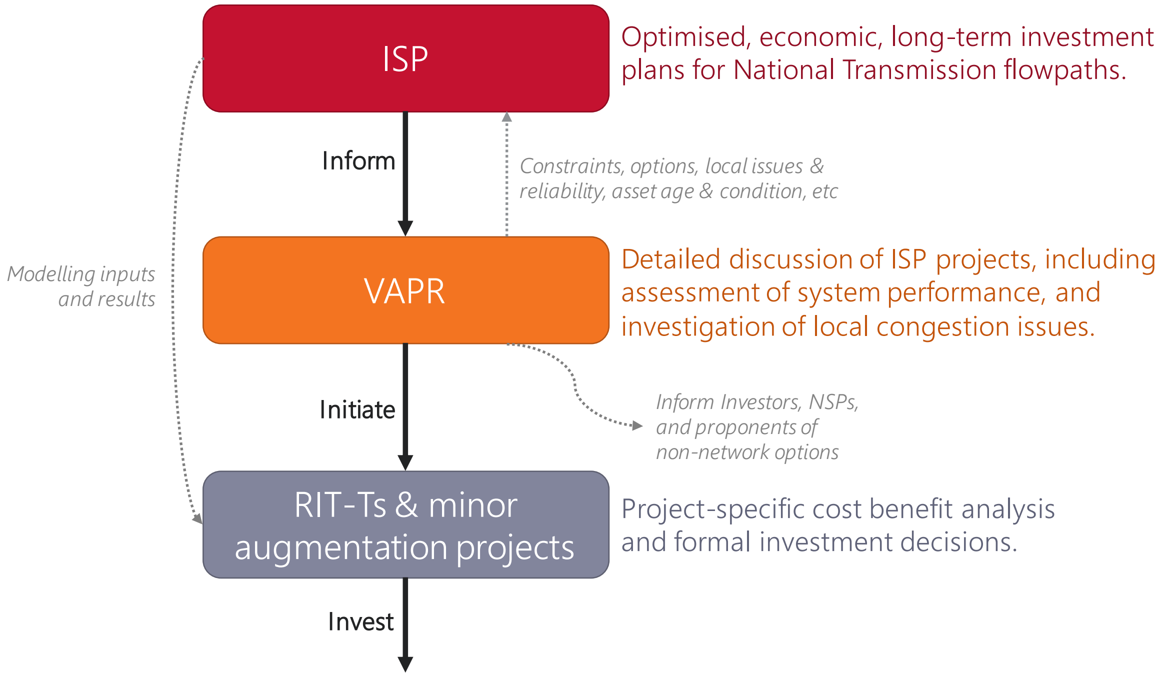
The VAPR currently sits alongside the ISP as a key component in the larger regulatory framework that aims to deliver efficient planning and economic investment across the NEM.

In alignment with a future, directly actionable ISP, the VAPR already leverages the nationally-optimised, long-term investment plans developed through the ISP process, and overlays these with more granular information on local congestion issues, and regional performance characteristics, in the Victorian DSN.

The VAPR studies are then used to inform interested parties in Victoria, trigger regulatory investment processes, or flow back into the ISP to improve and refine the results. This relationship is presented in the diagram below, and would accommodate future regulatory changes that streamline the RIT-T process or allow ISP-supported projects to be passed through to the RIT-T process more readily.

The 2019 VAPR strongly supports the work already underway to deliver on high priority work identified in the ISP, and a new 'Network developments' chapter (Chapter 3) has been introduced to report on the progress of these active ISP projects in Victoria.

Figure 1 Integration of the VAPR in the National Planning Framework



[6] ESB, *Converting the Integrated System Plan into action, Consultation paper*, May 2019, at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20-%20Converting%20the%20ISP%20into%20Action%20-%2020190517.pdf.

New state and national policy announcements

- The Victorian Government has committed to:
  - A Victorian Renewable Energy Target (VRET) of 40% by 2025, with a further target of 50% by 2030. The first round of VRET auction winners have been announced, representing 928 megawatts (MW) of newly committed renewable generation[7].
  - The Solar Homes scheme, which will deliver subsidised rooftop solar photovoltaic (PV) systems to 650,000 homes over the next 10 years, reducing system demand by as much as 2 gigawatts (GW) at times of peak solar output[8].
  - A battery storage incentive scheme, which will provide $40 million in grants to assist 10,000 homes over the next 10 years, with the potential to extend rooftop PV benefits into peak evening demand periods[9].
- The Federal Government is supporting Snowy 2.0 as part of its broader energy plan, and has committed up to $1.38 billion in equity investment with the remainder of the project to be financed by Snowy Hydro Limited[10]. This project has the potential to significantly affect the optimal development of the Victorian transmission system.

These policy changes have a significant impact on the identification of monitoring and emerging limitations in the Victorian network (Chapter 4), and on the changing investment landscape within the state (discussed in Chapter 6).

Progress on network planning and investment activities

- AEMO has published its Project Assessment Draft Report (PADR)[11] for the Western Victoria Renewable Integration RIT-T, which identifies the preferred option to upgrade network capacity and maximise the benefit of renewable connections in this region through reduced congestion.
- AEMO has published a Project Specification Consultation Report (PSCR)[12] jointly with TransGrid for the Victoria to New South Wales Interconnector upgrade. This project improves power transfers from Victoria to New South Wales and is intended to leverage low-cost renewables in the southern states and promote improved supply sharing between the two regions. The PADR for this project is expected in Q3 2019.
- AEMO has published its PADR for the Reactive Power RIT-T[13], which identifies the preferred option to maintain control of power system voltages in Victoria as minimum demand levels fall within the state.
- ElectraNet has successfully concluded its RIT-T process for a new South Australia to New South Wales Interconnector (including upgrades between Red Cliffs and Buronga)[14].
- TransGrid has published a PSCR to reinforce the New South Wales Southern Shared Network[15], which will assess the economic merits of upgrades between the Snowy region and Sydney, and may be required to capture market benefits associated with the Snowy 2.0 project.

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[7] For more information, see https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

[8] For more information, see https://www.solar.vic.gov.au/.

[9] Victorian Government media release, "Cheaper Electricity With Solar Batteries For 10,000 Homes", 11 September 2018, at https://www.premier.vic.gov.au/cheaper-electricity-with-solar-batteries-for-10000-homes/.

[10] Federal Government media release, "Historic Snowy 2.0 plan approved", 26 February 2019, at https://www.pm.gov.au/media/historic-snowy-20-plan-approved.

[11] At http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/RITT/Reports-and-project-updates.

[12] At http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PSCR.pdf.

[13] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission

[14] For more information, see https://www.electranet.com.au/projects/south-australian-energy-transformation/.

[15] At https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network

- TasNetworks has published a PSCR for the MarinusLink RIT-T[16], which will assess the economic merits of a second bass strait interconnector, leveraging hydro and renewable resources in Tasmania.

The 2019 VAPR explores the progress and significance of these developments in Chapter 3.

Unprecedented generator connection interest and investment within the state

- The Victorian fuel mix is rapidly changing as the state transitions to higher levels of renewable energy. Renewable generation sources currently make up almost 4.5 GW of capacity, accounting for 38% of the state's total generation capacity.
- 2.4 GW of renewables connections are currently committed, with an additional 8 GW of renewable generator projects proposed to connect. The majority of these projects are proposed to connect to the western Victoria network, presenting significant challenges due to transmission network limitations.
- The Snowy 2.0 project, intended to increase generation capacity by 2 GW, is being considered committed by AEMO, placing additional focus on the economic merits of augmenting the network between the Snowy Mountains, Sydney, and Melbourne.
- Some investors in Victoria are already facing unexpected economic and technical challenges associated with connection to weak transmission networks, including thermal and stability constraints, diminishing Marginal Loss Factors (MLFs), and surging system strength remediation investment costs.

Chapter 6 discusses this changing investment landscape in greater detail, and provides a range of information to assist new and intending participants to better understand the important locational signals and challenges associated with investment within the Victorian system.

Increasing operational challenges

- Minimum demand conditions remain a high priority, and voltage control issues at these times have emerged faster than anticipated. Short-term operational measures, such as network reconfiguration by de-energising transmission lines, have become necessary under some conditions. Forecast reductions in minimum demand over the next 10 years will exacerbate this issue, and continued ongoing reliance on operator actions to maintain network voltages will reduce system resilience.

  In December 2018, AEMO identified a gap for Network Support and Control Ancillary Service (NSCAS). To address this gap, AEMO has procured non-market ancillary services for reactive support in the short-term, while a formal RIT-T process is underway to deliver a long-term solution.
- Detailed system strength studies are progressing in Victoria, and are identifying weaker nodes and operating conditions. In late 2018, AEMO was required to direct units online to maintain system strength in Victoria following multiple concurrent plant outages in the Latrobe Valley. While no system strength gaps have been identified under system normal conditions in Victoria, the situation may deteriorate over time as local demand conditions change, and if further synchronous units withdraw from the system.

1.2 Supporting material

AEMO has published a suite of electronic resources to support the content in this report. Descriptions and links are provided in Table 1.

[16] At https://projectmarinus.tasnetworks.com.au/rit-t-process/.

Table 1 2019 VAPR supporting resources and links

Resource	Description and link
Interactive map	Provides data and analysis for a range of NEM topics including emerging development opportunities, transmission connection point forecasts, short-circuit levels, and national transmission plans. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboard
Historical DSN rating and loading workbook	Presents ratings and loadings for the 2018-19 maximum demand and high export periods presented in Chapter 2 and the interactive map. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report
AusNet Services 2019 asset renewal plan	Outlines AusNet Services' transmission asset renewal process and provides a list of its planned asset renewal projects, including asset retirements and de-ratings for the next 10-year period, including changes since last year and the various options considered. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report
Constraint reports	AEMO uses constraint equations to operate the DSN securely within power system limitations. The constraint equations are implemented in the National Electricity Market Dispatch Engine (NEMDE), which dispatches generation to ensure operation within the bounds of power system limitations. AEMO's annual and monthly constraint reports detail the historical performance of these constraint equations. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams
Demand forecasts	AEMO's independent connection point forecasts for Victoria. http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting
Additional data required in support of the Transmission Annual Planning Report guidelines	The Australian Energy Regulator (AER) has published an updated set of Transmission Annual Planning Report (APR) guidelines, requiring all transmission network service providers (TNSPs) to provide additional performance, capability, and system strength information from 2019 onwards. While the Victorian TNSP regulatory framework is unique compared to other NEM regions, the 2019 VAPR provides these additional details as part of the supplemental materials published alongside the report. This information includes: • Transmission connection point data for each transmission terminal station where primary station assets are associated with an actual or forecast emerging network limitation. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report • Transmission line segment data for each transmission line between terminal stations that are associated with a historical or emerging line capacity limitation. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report • Aggregated generation connection data for each connection application or new (completed over the last 12 months) connection agreement at terminal stations or areas where the connections could affect existing or emerging network limitations. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report

2. Network performance

This chapter assesses the performance of the Victorian DSN during 2018-19[17].

Key network performance insights

- The Victorian DSN remained secure under normal operating conditions in 2018-19, despite tightening supply-demand conditions, and record-breaking high temperatures that contributed to limited periods of supply shortfall.
- Minimum operational demand (3,484 MW) occurred at 1:30 pm on 28 October 2018, representing the first time that Victorian minimum demand has occurred during the afternoon rather than overnight. This highlights the impact that an increasing penetration of rooftop PV is having on the operational characteristics of the power system. Since June 2018, daily minimum demand in Victoria has occurred during midday and afternoon periods on 12 separate occasions.
- At times of low demand, AEMO has continued to rely on operator actions to maintain secure voltage levels, including the de-energisation of multiple 500 kilovolt (kV) transmission lines in Victoria.
  - In March 2019, AEMO entered a short-term Non-Market Ancillary Service (NMAS) agreement for the provision of additional voltage control support at times of minimum demand.
  - AEMO is separately progressing a RIT-T to deliver a long-term solution, and has commenced an open tender to source further interim NMAS services until the RIT-T process concludes.
- Extreme weather conditions contributed to several operating incidents in 2018-19:
  - In August 2018, a network separation event occurred following a lightning strike to the Queensland to New South Wales interconnector. This resulted in load shedding in Victoria. AEMO is actioning several recommendations to improve system resilience during events of this nature.
  - On 24 and 25 January 2019, during a period of prolonged high temperatures across multiple states, high levels of consumption coupled with unplanned generator outages resulted in insufficient supply to meet Victorian demand, and AEMO was required to activate load shedding.
- While the supply-demand balance has remained tight at times of peak demand, average exports from Victoria have increased compared with 2017-18, largely due to the increasing connection of new renewable generation in the region.
- Several terminal stations that have historically behaved as net loads have increasingly become net generation sources due to an increase in distributed energy resources (DER), particularly rooftop PV, coupled with distribution level generator connections. For example, measurements at Kerang Terminal Station show flows onto the transmission network over 27% of the time during the last 12 months. This demonstrates that distributed generation in the area often exceeds local electricity consumption.

[17] The period 1 April 2018 to 31 March 2019.

The following sections summarise AEMO's analysis of the Victorian DSN's performance. More detailed information is available on AEMO's online interactive map[18].

In this chapter, unless otherwise stated:

- Generation is defined as all scheduled, semi-scheduled, and non-scheduled generation greater than 30 MW and does not include rooftop PV.
- Demand and consumption are 'as generated', meaning they include generator auxiliary loads (electricity used by generators in their operations)[19].

2.1 How does AEMO assess network performance?

In evaluating the adequacy of the Victorian DSN in 2018-19, AEMO considered the following key network performance indicators:

- **Loading of transmission network elements at times of high network stress** – whether the transmission network had sufficient capacity to supply the demand (see Section 2.2).
- **Reactive power adequacy at times of high network stress and low demand periods** – the network's ability to maintain voltages within operational and design limits throughout the network (Section 2.2).
- **Notable power system incidents** – the frequency of incidents which resulted in system security violation or loss of customer load or generation (Section 2.3).
- **Interconnector capability** – the extent to which the operational and design limits of interconnectors restricted the import or export of generation (Section 2.4).
- **Impact of constraint equations** – the degree which transmission network constraints impacted on generation dispatch (Section 2.5).
- **Impact of the changing generation mix on the network** – how network flows are impacted by the increasing penetration of renewable generation and the shift in minimum demand timing (Section 2.6).

2.2 Network performance at times of high network stress

AEMO reviewed the loading of DSN network elements to assess levels of network stress during 2018-19.

To understand how the network performed at times of high stress, AEMO used five operational 'snapshots'[20] of the power system to capture network conditions[21] during periods of:

- Maximum demand.
- Minimum demand during the day.
- Minimum demand overnight.
- High export from Victoria[22].
- High levels of wind generation within Victoria.

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[18] Available at http://www.aemo.com.au/aemo/apps/visualisations/map.html.

[19] For further information on demand and consumption definitions, see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/EFI/2018/Operational-Consumption-definition---2018-update.pdf.

[20] Network adequacy assessment uses these snapshots, including any DSN outages. The snapshot data is obtained from the state estimator, which estimates the states (such as power, voltages, and angles) of the power system based on certain measurements in AEMO's Energy Management System (EMS).

[21] These snapshots do not necessarily represent the maximum loading experienced by every DSN asset, as this depends on prevailing system conditions such as generation patterns, interconnector flows, and time of localised peak demand, as well as factors that influence dynamic ratings, such as local temperature and wind speed.

[22] A high export period is classified as a snapshot with high flow through the South Morang F2 500/330 kV transformer, as this transformer is the most binding component limiting export to New South Wales.

While the Victorian daily minimum demand has historically occurred overnight, in 2018-19 it occurred during the afternoon for the first time. This trend is expected to continue in future years as minimum demand levels are increasingly driven by rooftop solar penetration. To represent this transition, both overnight and afternoon minimum demand snapshots have been considered in this section[23].

Table 2 Summary of operating conditions

	Maximum demand snapshot	Minimum demand (overnight) snapshot	Minimum demand (day) snapshot	High export from Victoria snapshot	High wind snapshot
Date and time[A]	24 January 2019 18:00:48	18 November 2018 04:01:17	28 October 2018 13:31:18	15 August 2018 07:01:17	14 April 2018 10:31:18
Victorian operational demand at time of snapshot[B]	9,328 MW	3,539 MW	3,484 MW	5,659 MW	4,906 MW
Sum of Victorian loads at time of snapshot	8,879 MW	3,484 MW	3,460 MW	5,521 MW	4,718 MW
Sum of Victorian generation at time of snapshot	8,327 MW	3,285 MW	3,854 MW	6,467 MW	5,311 MW
Sum of total Victorian available generation capacity at time of snapshot[C]	9,017 MW	3,775 MW	4,312 MW	7,174 MW	5,772 MW
Temperature in Melbourne	40.5 °C	10.2 °C	15.7 °C	12.9 °C	13.2 °C
Power flow from Victoria to South Australia (Heywood Interconnector)	-64 MW	-53 MW	207 MW	-337 MW	-404 MW
Power flow from Victoria to South Australia (Murraylink)	35 MW	0 MW	43 MW	-54 MW	0 MW
Power flow from Tasmania to Victoria	459 MW	-157 MW	-397 MW	480 MW	0 MW
Power flow from Victoria to New South Wales	-344 MW	-370 MW	-310 MW	1,605 MW	818 MW
Reliability and Emergency Reserve Trader (RERT)	180 MW (VIC) 216 MW (SA)	0 MW	0 MW	0 MW	0 MW

[23] Reducing minimum demand and its shift to day periods is discussed in Section 2.6.

	Maximum demand snapshot	Minimum demand (overnight) snapshot	Minimum demand (day) snapshot	High export from Victoria snapshot	High wind snapshot
Victorian renewable generation					
Wind	354 MW	330 MW	145 MW	1,071 MW	1,184 MW
Solar	156 MW	3 MW	100 MW	0 MW	0 MW
Hydro	2,097 MW	0 MW	25 MW	1,031 MW	29 MW
Rooftop PV	229 MW	0 MW	1,026 MW	0 MW	154 MW
Battery storage	25 MW	0 MW	0 MW	0 MW	0 MW
System security	Potential overload of the Dederang to South Morang 330 kV line for parallel line loss. Load shedding to maintain security.	Lines de-energised and unit directed online to manage voltage due to low demand and multiple generator outages	System normal, no contingency overloads	System normal, no contingency overloads	System normal, no contingency overloads

A. All values listed, excluding temperature, are the values measured at the exact time of each snapshot for the region of Victoria.
B. Operational demand is the sum of all Victorian loads and network losses.
C. Available generation capacity is the maximum capacity (MW output) at the time of the snapshot. It does not include capacity from generators that were out of service at the time. It reflects the maximum target a generator can be requested to reach within a given dispatch interval, and is equal to generation for all semi-scheduled and non-scheduled generators.

2.2.1 Maximum demand snapshot

This snapshot captures the conditions when many network elements experience their maximum loading for the year. The discussion in this is complemented by additional information provided in the historical DSN rating and loading workbook[24].

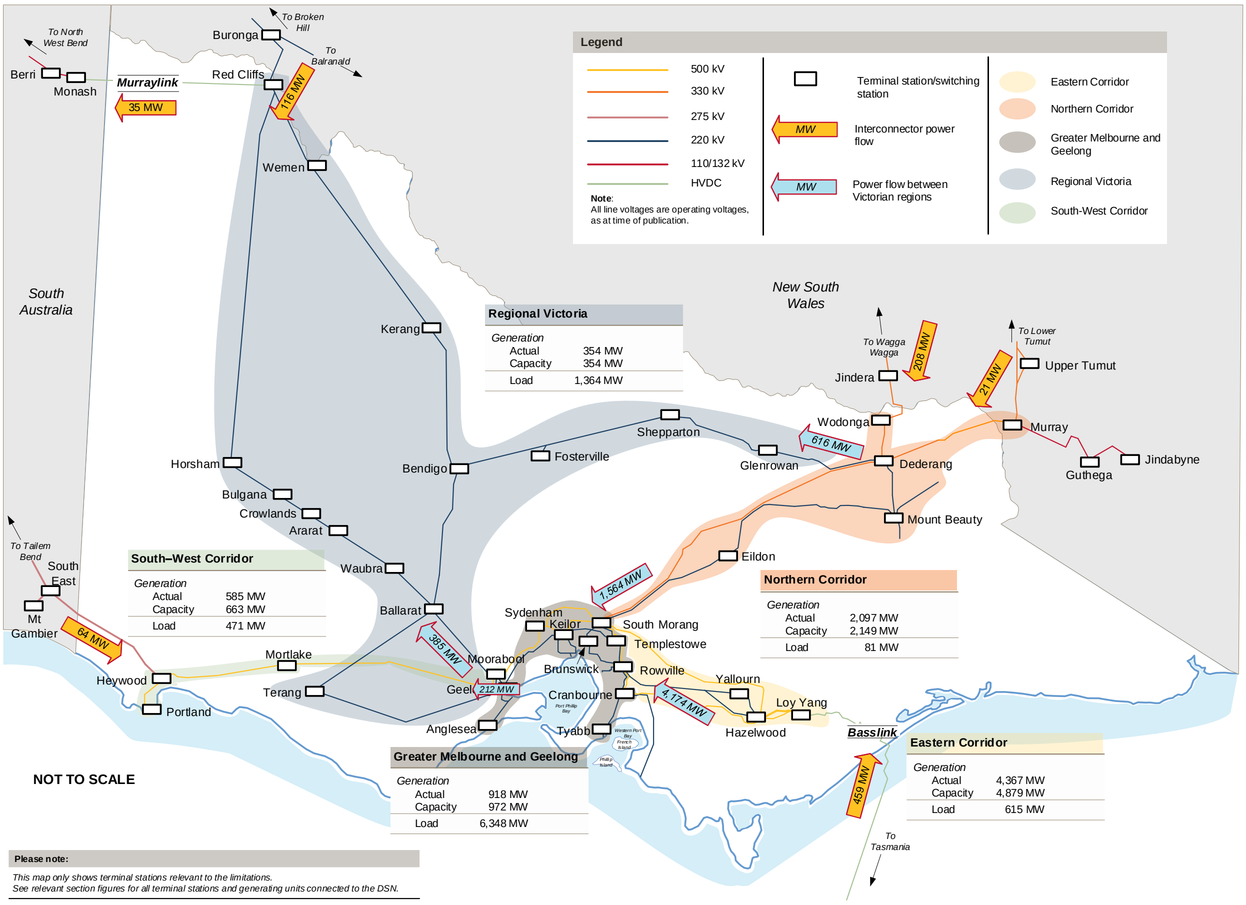
Figure 2 represents the prevailing conditions at the time of maximum operational demand in Victoria (6:01 pm on 24 January 2019), and shows the following scenario:

- 71% (6,348 MW) of the total Victorian demand (8,879 MW) was concentrated in Greater Melbourne and Geelong.
- Most of the Victorian generation (52%) originated from the Eastern Corridor.
- Net power flow from New South Wales to Victoria was limited at 344 MW due to thermal limitations. This comprised an import of 228 MW from Murray and Wodonga and 116 MW from Buronga on the New South Wales – Victoria interconnector. Refer to Section 4.4.1 for further detail on thermal limitations on New South Wales to Victoria import capability, and options to address these limitations.
- Net power flow from South Australia to Victoria was 29 MW, comprised of import of 64 MW on the Heywood Interconnector and export of 35 MW on the Murraylink interconnector.
- Power flow from Tasmania to Victoria was 459 MW via the Basslink interconnector.
- 180 MW of Reliability and Emergency Reserve Trader (RERT) was dispatched in Victoria, and 216 MW was dispatched in South Australia.

[24] For the maximum demand snapshot ratings and loadings, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report.

- Power flow on the New South Wales – Victoria interconnector and Murraylink exceeded transfer limits at the time of this snapshot, and load shedding subsequently occurred to maintain power system security (see Section 2.3 for further detail on this load shedding event).

Figure 2 Maximum demand snapshot: generation, load, and interconnector flow



Note that during this maximum demand snapshot:

- There was 229 MW of rooftop PV generation, serving 2.5% of end user demand.
- There was 2,608 MW of renewable generation (31.3% of total Victorian generation), comprised of non-scheduled wind (21 MW), dispatched wind (334 MW), dispatched solar (156 MW), and hydroelectric generation (2,097 MW).
- There was also 25 MW of generation supplied by battery storage.

The actual maximum demand of 9,328 MW was slightly lower than the 50% probability of exceedance (POE)[25] maximum demand forecast of 9,446 MW. The 10% POE maximum demand forecast was 10,227 MW[26]. This snapshot occurred during an incident in Victoria where RERT was activated, and just prior to a declared Lack of Reserve (LOR) 3[27] and subsequent load shedding. AEMO estimates that, if RERT and load shedding were not required, maximum demand would have reached approximately 9,746 MW, exceeding the 50% POE forecast but still being significantly less than the 10% POE forecast.

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[25] POE is the likelihood that a demand forecast will be met or exceeded. A 10% POE maximum demand projection is expected to be exceeded, on average, one year in 10, while a 50% POE forecast is based on average weather and is expected to be exceeded, on average, every second year.

[26] For maximum demand forecasts, see http://forecasting.aemo.com.au/Electricity/MaximumDemand/Operational.

[27] LOR notices are issued by AEMO to indicate to market participants a tightening in available supply reserves, with notices increasing from LOR 1 to LOR 3 to give clear signals that the system is approaching a point where AEMO, as operator, would need to shed load to avoid system loss. See NER rule 4.8.4 for definitions.

Further, if no intervention/load shedding had occurred over 24 and 25 January, the moment of highest network stress (due to a combination of estimated peak customer load and peak temperature) would have occurred on 25 January at 1:00 pm (rather than 24 January at 6:01 pm). Peak demand normally occurs later in the day, however a cool front early in the afternoon meant temperatures in Victoria (and therefore electricity demand in Victoria) peaked earlier on this day. The load shedding incident that occurred on 24 and 25 January is discussed in Section 2.3.

2.2.2 Minimum demand (day) snapshot

This snapshot captures conditions under which voltages may exceed operating limits. Figure 3 presents the prevailing conditions at the time of minimum demand in Victoria (1:31 pm on 28 October 2018). This is the first time that annual minimum demand has occurred during the afternoon rather than overnight (although it may have also occurred during the afternoon in 2017-18 if not for an unplanned Alcoa Portland (APD) outage in the early morning of 12 November 2017).

This shift from overnight to afternoon is largely the result of increased rooftop PV, which AEMO forecasts will continue putting downward pressure on minimum demands and result in more frequent afternoon lows.[28] Further details on the impacts of rooftop PV on minimum demand are discussed in Section 2.6.

Figure 3 Minimum demand (day) snapshot: generation, load, and interconnector flow

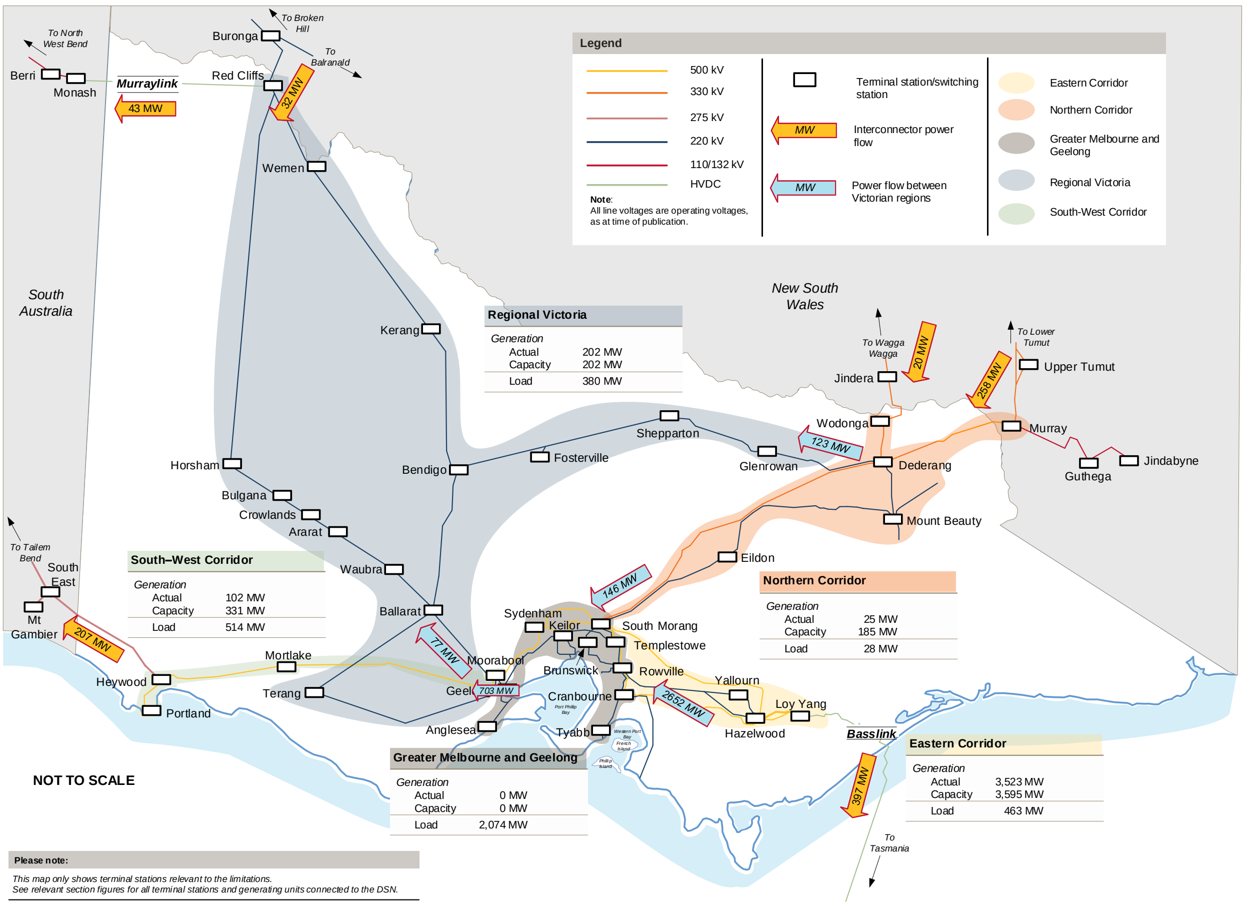


Figure 3 shows the following scenario:

- 60% (2,074 MW) of the total Victorian demand (3,460 MW) was concentrated in Greater Melbourne and Geelong.

[28] For minimum demand forecasts, see http://forecasting.aemo.com.au/Electricity/MinimumDemand/Operational.

- Most of the Victorian generation (91%) originated from the Eastern Corridor.
- Net power flow from New South Wales to Victoria was 310 MW. This comprised an import of 278 MW from Murray and Wodonga and 32 MW from Buronga on the New South Wales – Victoria interconnector.
- Net power flow from Victoria to South Australia was 249 MW, comprised of export of 207 MW on the Heywood Interconnector and 43 MW on the Murraylink interconnector.
- Power flow from Victoria to Tasmania was 397 MW via the Basslink interconnector.
- All interconnector flows were within their thermal limits.

Note that during this minimum demand snapshot:

- There was 1,026 MW of rooftop PV generation, serving 22.9% of end user demand.
- There was 270 MW of renewable generation (7.0% of total Victorian generation), comprised of non-scheduled wind (65 MW), dispatched wind (80 MW), dispatched solar (100 MW), and hydroelectric generation (25 MW).

A review of asset loading at the time of minimum demand showed that the Victorian DSN performed within technical network limits for secure operation. There were no operational measures required to maintain voltages within operating limits.

2.2.3 Minimum demand (overnight) snapshot

This snapshot captures a condition under which voltages may exceed operating limits. The Victorian demand captured in this snapshot is higher than that presented in the previous section for the 'Minimum demand (day) snapshot', however assessment of overnight minimum demand has been retained in the 2019 VAPR because the overnight snapshot may still represent the highest stress in terms of voltage control.

Figure 4 represents the prevailing conditions at the time of minimum demand (overnight) in Victoria (4:01 am on 18 November 2018). It shows:

- 58% (2,007 MW) of the total Victorian demand (3,484 MW) was concentrated in Greater Melbourne and Geelong.
- Most of the Victorian generation (90%) originated from the Eastern Corridor.
- Net power flow from New South Wales to Victoria was limited to 370 MW. This comprised an import of 310 MW from Murray and Wodonga and 60 MW from Buronga on the New South Wales – Victoria interconnector.
- Net power flow from South Australia to Victoria was 53 MW, comprised of import of 53 MW on the Heywood Interconnector and 0 MW on the Murraylink interconnector.
- Power flow from Victoria to Tasmania was 157 MW via the Basslink interconnector.
- All interconnector flows were within their thermal limits.

Note that during this minimum demand (overnight) snapshot:

- There was no rooftop PV generation because the snapshot occurred before sunrise.
- There was 333 MW of renewable generation (10.1% of total Victorian generation), comprised of non-scheduled wind (136 MW), dispatched wind (194 MW), and no hydroelectric generation.

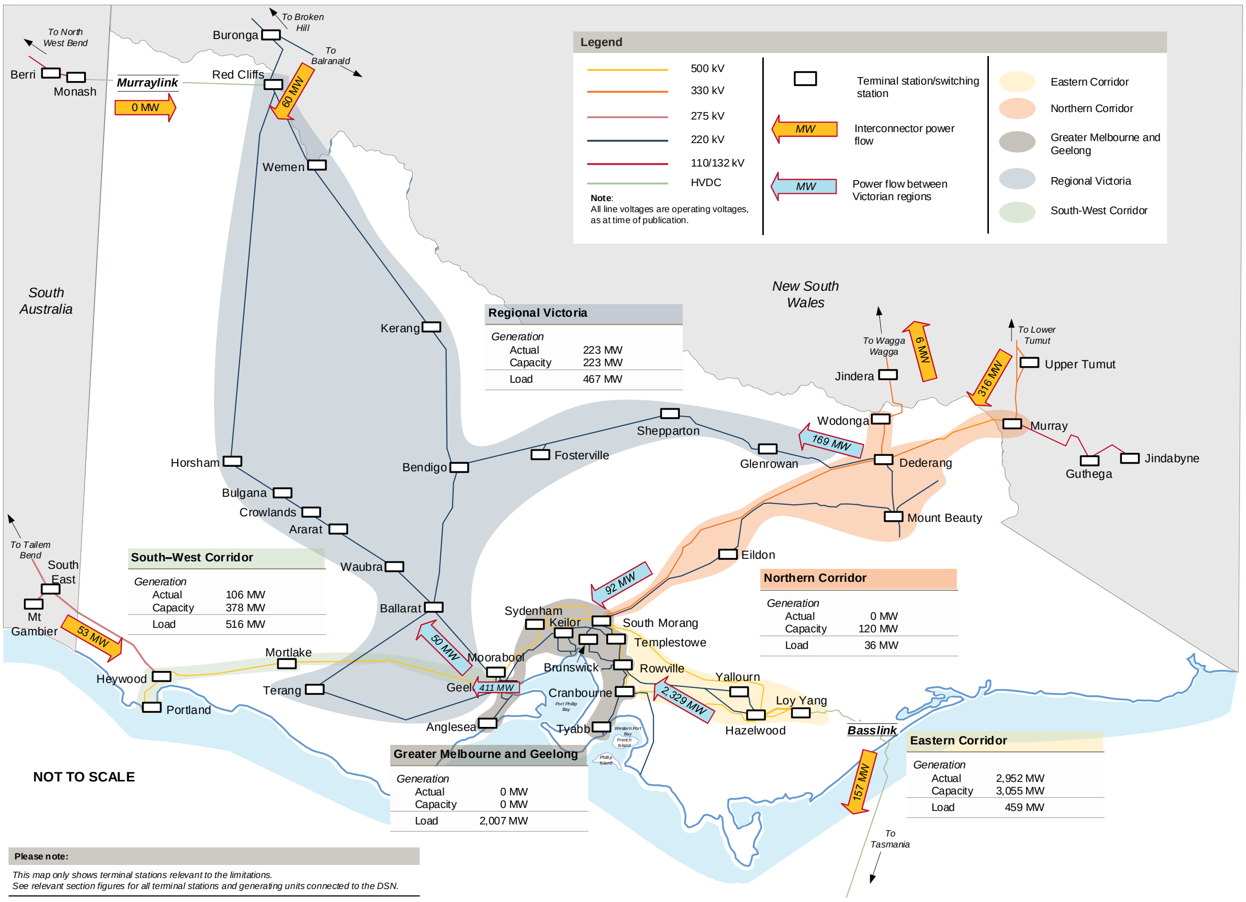
From 16 to 18 November 2018, including during the minimum demand (overnight) snapshot, several normally operating baseload power stations and a reactor were out of service, which reduced the available reactive support in the Victorian system.

During this period, operational measures were applied to maintain voltages within operational limits, including the de-energisation of multiple 500 kV lines, and the use of Directions to ensure sufficient reactive support was available.

The frequency and extent of voltage control interventions has increased rapidly, and these repeated actions can reduce system resilience and pose additional power system security risks. In response, AEMO commenced a RIT-T in May 2018 to assess the technical and economic benefits of delivering additional reactive power support in Victoria.

In December 2018, AEMO also identified an immediate gap for Network Support and Control Ancillary Services (NSCAS) in Victoria[29] and subsequently entered into a Non-Market Ancillary Service (NMAS) agreement to address this gap in the short term while the RIT-T progresses to deliver a long-term solution. Further details are discussed in Section 3.2.

Figure 4 Minimum demand (overnight) snapshot: generation, load, and interconnector flow



2.2.4 High export snapshot

This snapshot demonstrates network conditions during times of high export from Victoria to New South Wales, specifically through the South Morang F2 500/330 kV transformer.

This section is complemented by additional information provided in the historical DSN rating and loading workbook[30].

Figure 5 presents the prevailing conditions at the time of high export from Victoria to New South Wales (7:01 am on 15 August 2018). It shows:

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[29] AEMO, 2018 *National Transmission Network Development Plan* (NTNDP), December 2018, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

[30] For the high export snapshot ratings and loadings, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report.

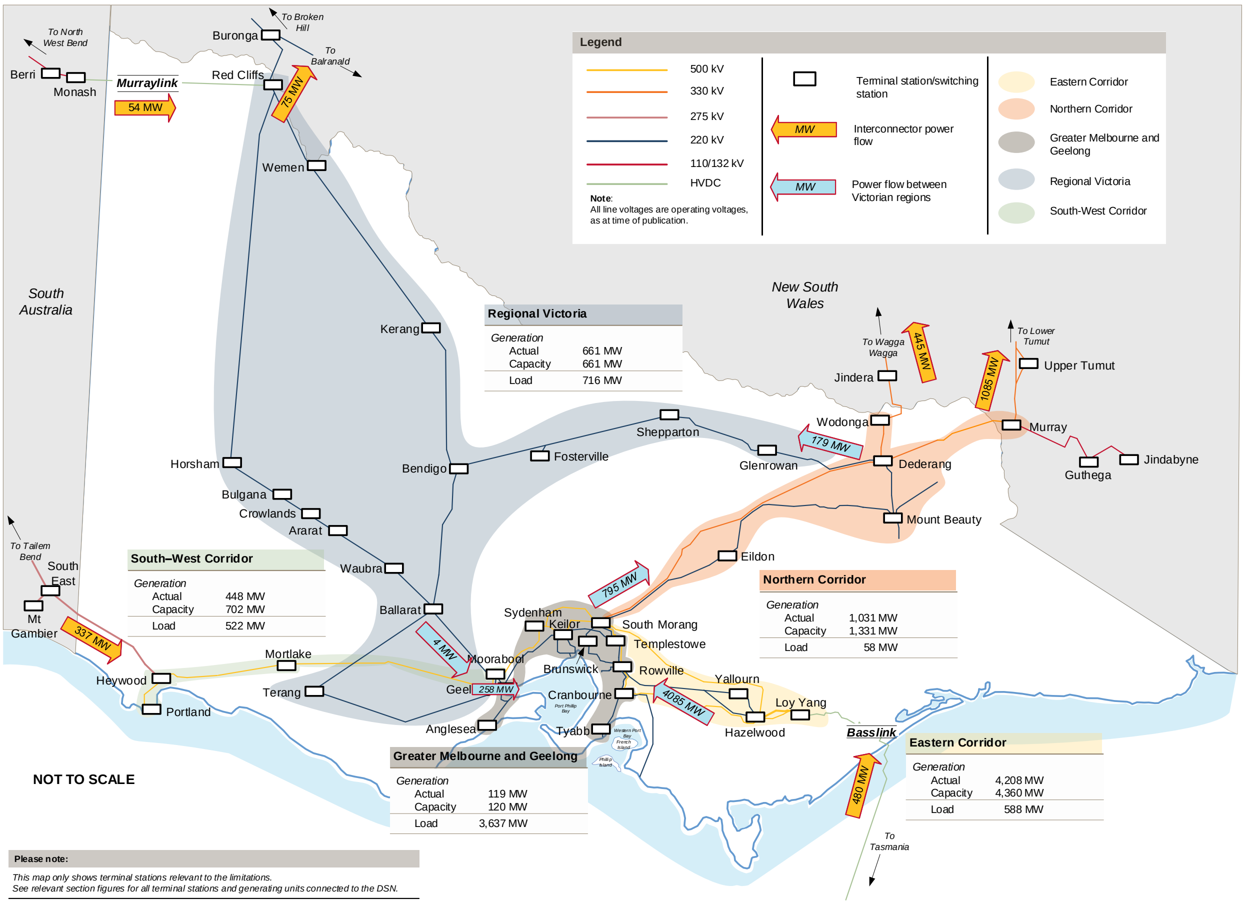
- 66% (3,637 MW) of the total Victorian demand (5,521 MW) was concentrated in Greater Melbourne and Geelong.
- Most of the Victorian generation (65%) originated from the Eastern Corridor.
- Net power flow from Victoria to New South Wales was 1,605 MW. This comprised an export of 1,530 MW from Murray and Wodonga and 75 MW to Buronga on the New South Wales – Victoria interconnector.
- Net power flow from South Australia to Victoria was 391 MW, comprised of import of 337 MW on the Heywood Interconnector and 54 MW on the Murraylink interconnector.
- Power flow from Tasmania to Victoria was 480 MW via the Basslink interconnector.
- All interconnector flows were within their thermal limits.

Note that during this high export snapshot:

- There was no rooftop PV generation because the snapshot occurred before sunrise.
- There was 2,103 MW of renewable generation (32.5% of total Victorian generation), comprised of non-scheduled wind (385 MW), dispatched wind (686 MW), and hydroelectric generation (1031 MW).

An assessment of asset loading at the time of high export reveals that the Victorian DSN performed within technical network limits for secure operation.

Figure 5 High export snapshot: generation, load, and interconnector flow



2.2.5 High wind snapshot

The high wind snapshot captures conditions under which the Victorian network experienced high wind generation output. Key summary indicators are provided in Table 2.

Operational demand at the time of the snapshot was neither high enough to cause risk of thermal overload, nor low enough to develop the potential of over-voltages. This highlights that there was no significant visible stress on the network due to high wind generation.

The level of renewable generation penetration is expected to increase in Victoria to meet the VRET. The majority of renewable generation connection interest is in Western Victoria, where interest currently exceeds transmission capacity.

AEMO is progressing the Western Victoria Renewable Integration RIT-T which seeks to reduce emerging constraints in the Western Victorian transmission network by reducing local congestion for existing and anticipated low-cost generation projects in this part of the state. Details on this RIT-T are presented in Section 3.1. Further detail on challenges associated with increased connections is presented in Chapter 6.

2.3 Victorian power system reviewable operating incidents

Over the 12-month review period[31], the DSN was operated in a secure and reliable operating state except for:

- **Three incidents where customer load was shed to maintain power system security**.
  - On 25 August 2018, a lightning strike on the Queensland to New South Wales interconnector resulted in separation events between Queensland and New South Wales, and between Victoria and South Australia[32]. Although the frequency standard in Victoria was not breached, the resulting supply deficit led to a reduction in system frequency and subsequent load shedding in Victoria. AEMO has investigated this incident and is actioning recommendations to improve system resilience during events of this nature.
  - Two distinct load shedding events occurred on 24 and 25 January which impacted system reliability[33]. This event was the result of extreme temperature conditions in South Australia and Victoria, coupled with unplanned reductions in supply availability (due to equipment failures and urgent plant maintenance).
  - Although AEMO dispatched all available contracted reserves through RERT[34], and utilised all available inter-regional transfer capacity, there remained a supply shortfall in Victoria. To maintain power system security, AEMO instructed load shedding in Victoria on both 24 January and 25 January.
  - On 24 January 2019, approximately 75 MW of load was shed over a two-hour period, while on 25 January 2019, approximately 270 MW of load was shed over a three-hour period.

These incidents are presented in Table 3.

Further information on power system operating incidents can be found on AEMO's website[35].

Because AEMO is responsible for operating the transmission network, this section does not consider distribution network events that may have resulted in loss of supply.

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[31] The VAPR reviews the period 1 April 2018 to 31 March 2019.

[32] AEMO, *Final Report – Queensland and South Australia system separation on 25 August 2018*, January 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

[33] AEMO, *Load Shedding in Victoria on 24 and 25 January 2019*, April 2019, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf.

[34] On 24 January 2019, up to 180 MW of unscheduled reserves from nine RERT contracts in Victoria and 216 MW of unscheduled reserves from two RERT contracts in South Australia were activated between 4:00 pm and 10:30 pm. On 25 January, up to 454 MW of unscheduled reserves from all 10 available RERT contracts in Victoria were activated between 9:00 am and 4:30 pm.

[35] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports.

Table 3 Summary of significant reviewable power system incidents during 2018-19

Date	Incident	Consequence
25 August 2018	Queensland and South Australia system separation	Combined 997.3 MW customer load reduction in Victoria and New South Wales
24-25 January 2019	Load shedding in Victoria	75 MW customer load reduction on 24 January 270 MW customer load reduction on 25 January

Consistent with NER clause S5.1.2, AEMO plans, designs, and maintains the Victorian DSN to meet system normal conditions and following any single credible contingency event. While the above events impacted power system security and reliability, they occurred under conditions more severe than the credible contingency events stipulated in the NER, or with multiple prior outages in effect.

AEMO continues to review the probability and severity of such events to refine the operating envelope considered in its *Victorian Electricity Planning Approach*[36].

2.4 Interconnector capability over 2018-19

An interconnector's capability depends on the performance of the network, which varies throughout the year. Notional interconnector limits can be found in AEMO's interconnector capabilities report[37]. A detailed summary of the capability and limits of each interconnector in the NEM is provided in AEMO's Monthly and Annual NEM Constraint Reports[38].

Table 4 provides an indication of interconnector utilisation and shows there has been a decrease in the duration of energy exports from Victoria over the last two years – consistent with the closure of the Hazelwood Power Station in 2017.

Table 4 Percentage (%) of time interconnector is exporting energy from Victoria

Interconnector	5-year average before Hazelwood closure	2017-18	2018-19
Victoria – New South Wales interconnector	86%	44%	55%
Heywood Interconnector	81%	49%	51%
Murraylink	43%	40%	51%
Basslink	42%	52%	50%
Victoria (Net)	86%	51%	60%

While still lower than the five-year average, the duration of energy exports from Victoria increased in 2018-19 compared to the previous year. This increase was due to an increase in renewable generation connections (see Section 4.2 for more detail on connections since the 2018 VAPR).

[36] AEMO, *Victorian Electricity Planning Approach*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf.

[37] AEMO, *Interconnector Capabilities Report*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2017/Interconnector-Capabilities.pdf.

[38] Monthly and Annual NEM Constraint reports for the calendar year are available through the Statistical Reporting Streams page on the AEMO website, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams.

AEMO expects that this trend of increasing exports will continue as new renewable generation is connected to meet the VRET. AEMO and TransGrid have also jointly commenced a RIT-T project to further improve power transfers from Victoria to New South Wales. Section 3.3 provides more detail on the purpose and status of this RIT-T project.

The supply-demand balance remained tight in Victoria during 2018-19, with both RERT and load shedding activated to maintain system security in January 2019. While these events were the result of extreme weather conditions and multiple unplanned plant outages, further increases to Victorian import capabilities would enable better utilisation of spare reserves in neighbouring regions during such events.

Section 4.4.1 provides further consideration of the existing thermal import limitations from New South Wales to Victoria, while Section 4.4.2 discusses potential future works to significantly increase network capacity between the two regions.

The Heywood Interconnector continues to operate below its maximum design limit of 650 MW in both directions, due to stability risks which were identified following the South Australia system black event[39]. The maximum transfer currently allowed is 600 MW from Victoria to South Australia, and 500 MW from South Australia to Victoria. A testing program is ongoing, and the current capacity limit will be increased once residual operational concerns are fully addressed for both steady-state and transient conditions.

2.5 Impact of Victorian transmission constraints

Table 5 summarises the binding constraints on the Victorian transmission system which resulted in the highest market impacts in the 2018 calendar year. Comparison values are also shown for 2017. This is a subset of the detailed constraint equation information provided in AEMO's Annual NEM Constraint Reports for 2017 and 2018[38].

In 2018, the constraint equation with the largest market impact (V>>V_NIL_1x) restricts flow on the Murray – Dederang 330 kV lines for loss of the parallel line. The market impact of this constraint has increased significantly since 2017 due to several periods of high demand in Victoria coupled with high levels of Murray generation increasing utilisation of the Murray – Dederang 330 kV lines.

This constraint can also act to restrict imports into Victoria, and AEMO is currently exploring options to increase import capability from New South Wales. Section 4.4.1 provides further details on these incremental works, while Section 4.4.2 discusses potential options that significantly increase network capacity between the two regions.

Constraint equations 5 and 8 restricted Victoria – New South Wales export, although the market impact of these constraints decreased in 2018. While the interconnector spent more total hours exporting during 2018 (see Section 2.4), it spent less time exporting at its limit. AEMO and TransGrid are jointly progressing a RIT-T project to improve exports from Victoria to New South Wales by further relieving these constraints. Section 3.3 provides more information on the purpose and status of this RIT-T.

Constraint equation 7 restricts export from Victoria to South Australia. This constraint equation represents a 600 MW limit to avoid overloading the Heywood Interconnector, and has been applied as part of the test program for the Heywood Interconnector upgrade. This constraint equation's market impact decreased in 2018 as the Heywood Interconnector operated at its limit in 2018 for less time than in 2017.

[39] AEMO, *Black System in South Australia, 28 September 2016,* March 2017, listed under 2016 reports at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports.

Table 5 Equations with persistent market impacts in both 2017 and 2018

ID	Equation ID	Binding hours		Market impact[A]		Description
		2017	2018	2017	2018	
1	V>>V_NIL_1x	1	12	$294	$525,711	To avoid overloading either Murray to Dederang 330 kV lines for a trip of the parallel line when the DBUSS-Line control scheme is enabled.
2	V>SMLARHO1		50		$272,270	To avoid overloading or voltage collapse on the Buronga to Balranald to Darlington Point (X5) 220 kV line for a trip of the Bendigo to Kerang 220 kV line, when either Ararat to Crowlands 220 kV or Crowlands to Horsham 220 kV lines are not available.
3	V>>V_NIL_8	1	12	$210	$200,213	To avoid overloading the Dederang to Wodonga 330 kV line for a trip of the Lower Tumut to Wagga 330 kV line and multiple 132 kV lines from Yass.
4	V^SML_NSWRB_2	53	60	$441,280	$151,776	To avoid voltage collapse for loss of Darlington Pt to Buronga (X5) 220 kV line when the NSW Murraylink runback scheme is not available.
5	V::N_NIL_xxx	625	271	$181,973	$115,464	To prevent transient instability for a trip of a Hazelwood – South Morang 500 kV line.
6	V^^N_NIL_1[B]		68		$57,329	To avoid voltage collapse around Murray for loss of all APD potlines.
7	V:S_600_HY_TEST _DYN	289	90	$659,212	$48,946	600 MW limit on VIC to SA transfer on Heywood with dynamic headroom.
8	V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	312	145	$143,897	$43,440	To avoid overloading the South Morang F2 transformer when Yallourn Unit 1 is in 220 kV mode and Hazelwood is operating in radial mode.
9	V::N_SETB_xxx		85		$41,780	To prevent transient instability for a trip of a Hazelwood – South Morang 500 kV line when a South East to Tailem Bend 275 kV line is not available.
10	V>>N-NIL_HA	13	30	$8,228	$24,066	To avoid overloading the Murray to Upper Tumut 330 kV line for a trip of the Murray to Lower Tumut 33 kV line.
Total		1294	823	$1,435,094	$1,480,995	

A. The market impact of a constraint is derived by summarising the marginal value for each dispatch interval from the marginal constraint cost re-run over the period considered.
B. This stability limit was introduced in August 2018, hence there was no market impact in 2017

It is also noted that the market impact of:

- Constraint equation 2 was significant in 2018 due to multiple outages of the Ararat – Horsham 220 kV line prior to Crowlands Terminal Station commissioning in 2018 and Ararat – Crowlands or Crowlands – Horsham 220 kV lines after commissioning. There was no market impact in 2017 because there were no Ararat – Horsham 220 kV line outages.
- Constraint equation 3 increased in 2017 due to several occurrences of combined high flow on the Dederang – Wodonga 330 kV line, Lower Tumut – Wagga 330 kV line, Yass – Wagga 132 kV line, and Yass – Murrumbrah 132 kV line.
- Constraint equation 4 did not change significantly.

- Constraint equation 6 was newly introduced in August 2018.
- Constraint equation 9 was more significant in 2018 due to multiple outages of a South East – Tailem Bend 275 kV line. There were no outages of a South East – Tailem Bend 275 kV line in 2017 and hence no market impact.
- Constraint equation 10 increased in 2018 due to the increased duration of Victoria – New South Wales exports as a result of more renewable generation connections in Victoria.

2.6 Impact of changing generation mix

Strong investor interest in western parts of Victoria is shifting the geographic diversity of supply sources away from the Latrobe Valley, while the increasing penetration of non-synchronous generation is changing the technical characteristics of the system. Overlaid on this, consumer response through investment in DER (such as rooftop PV) is continuing to change the patterns of network flows within the state.

This section reviews network performance under high levels of renewable generation output, and investigates the effects on demand and network operation. This section considers:

- Frequency of reverse flow occurrences (from the distribution network into the DSN) as a result of renewable generation connected to the distribution system and behind-the-meter (customer premises).
- Impact of rooftop PV on regional demand, and subsequent challenges it may pose to the network.

Reverse flows

The frequency and magnitude of reverse power flows continues to increase in Victoria, with more terminal stations experiencing reverse flows in 2018-19 than previously observed. In some cases, terminal stations that have historically behaved as net loads are behaving increasingly like net generation sources. This is due to an increase in the volume and geographic distribution of generators connecting at the sub-transmission and distribution level. Section 4.2 provides more detail on new generator connections since the 2018 VAPR.

Table 6 outlines the number of hours that reverse flows occurred at the five terminal stations which experienced the most significant reverse flows during 2018-19. Key observations relating to these assets include that:

- Kerang 220/66/22 kV transformers experienced net flows onto the transmission system 27% of the time during 2018-19 (compared to 0% in 2017-18). This follows the connection of Gannawarra Solar Farm in October 2018.
- Terang 220/66 kV transformers experienced net flows onto the transmission system 19% of the time during 2018-19 (compared to 1% in 2017-18). This follows connection of Salt Creek Wind Farm in July 2018.
- Horsham 220/66 kV transformers experienced net flows onto the transmission system 16% of the time during 2018-19 (compared to 5% in 2017-18). This follows connection of Kiata Wind Farm in late 2017.
- Wemen 220/66 kV transformers experienced net flows onto the transmission system 14% of the time during 2018-19 (compared to 0% in 2017-18). This follows connection of Bannerton Solar Park, which is currently undergoing commissioning.
- Red Cliffs 220/66/22 kV transformers experienced net flows onto the transmission system 4% of the time during 2018-19 (compared to 0% in 2017-18). This follows connection of Karadoc Solar Farm in March 2019.

These insights confirm the impact that changes in the distribution and sub-transmission network are having at a transmission level. As these effects continue to grow and change, they will present new operational and network planning challenges.

Table 6 Number of hours reverse flows occurred at identified locations

Year	Autumn	Winter	Spring	Summer	Total[A]
Kerang					
2017-18	0 hrs	0 hrs	0 hrs	0 hrs	0 hrs
2018-19	308 hrs	485.5 hrs	812.5 hrs	802.5 hrs	2,408.5 hrs
Terang					
2014-15	13 hrs	0 hrs	7.5 hrs	10.5 hrs	31 hrs
2015-16	25.5 hrs	9.5 hrs	5.5 hrs	6 hrs	46.5 hrs
2016-17	37.5 hrs	9.5 hrs	43.5 hrs	25 hrs	115.5 hrs
2017-18	35.5 hrs	8 hrs	24 hrs	20 hrs	87.5 hrs
2018-19	211 hrs	575.5 hrs	500.5 hrs	367.5 hrs	1,654.5 hrs
Horsham					
2016-17	0 hrs	0 hrs	0 hrs	0 hrs	0 hrs
2017-18	187 hrs	0 hrs	0 hrs	283 hrs	470 hrs
2018-19	299 hrs	441 hrs	472.5 hrs	230 hrs	1,442.5 hrs
Wemen					
2017-18	0 hrs	0 hrs	0 hrs	0 hrs	0 hrs
2018-19	256 hrs	0 hrs	276.5 hrs	733.5 hrs	1,266 hrs
Red Cliffs					
2017-18	0 hrs	0 hrs	0 hrs	0 hrs	0 hrs
2018-19	57 hrs	0 hrs	33.5 hrs	235 hrs	325.5 hrs

A. The total hours differ from the values published in the 2018 VAPR due to an update to the calculation methodology.

Strong coordination is important between TNSPs and distribution network service providers (DNSPs) to monitor and manage these changing flow patterns. AEMO is currently undertaking a review of existing asset control schemes in Victoria to revalidate their underlying assumptions, and ensure they remain fit-for-purpose.

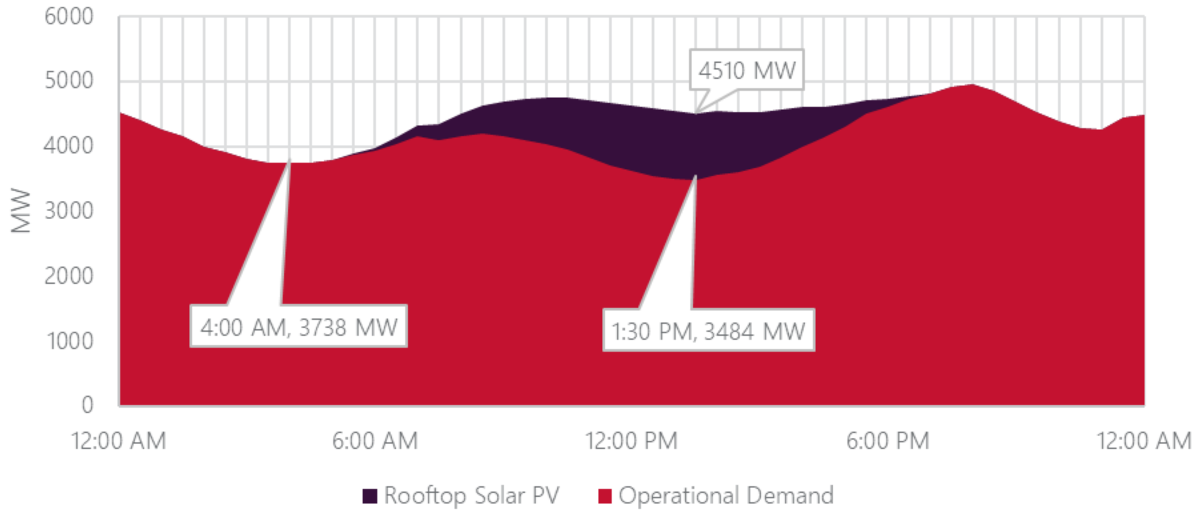
Impact of rooftop PV on minimum demand

Rooftop PV has the greatest impact on operational demand between 8:00 am and 5:00 pm, reducing already low demands in the early afternoon, and contributing to reductions in the morning and late afternoon peaks.

Rooftop PV penetration in Victoria increased by more than 400 MW between December 2017 and March 2019, with a peak rooftop PV output of approximately 1,150 MW at 12:30 pm on 7 March 2019.

As discussed in Section 2.2.2, this increasing penetration of rooftop PV has already resulted in a shift of Victorian minimum demand from overnight to the early afternoon. At the time of minimum demand in 2018-19, rooftop PV had an aggregate output of over 1,000 MW. Without rooftop PV, minimum demand would have occurred at 4:00 am instead of 1:30 pm on this day, as illustrated in Figure 6.

Figure 6 Victorian demand profile of 2018-19 minimum demand day (28 October 2018)



During 2018-19, there were 12 occurrences where the daily minimum demand occurred between 11:30 am and 2:30 pm. During these 12 events, rooftop PV had an aggregate output of 800 MW or above, and nine of these events occurred between September and November 2018.

With initiatives such as the Solar Homes scheme[40], Victoria's installed rooftop PV capacity will continue to grow, and AEMO projects a continued trend of reducing minimum demands[41]. This presents operational challenges for maintaining system voltages, and AEMO has identified an associated NSCAS gap. Section 3.2 provides more detail on AEMO's current works to deliver additional voltage control support.

[40] For more information, see https://www.solar.vic.gov.au/.

[41] For minimum demand forecasts, see http://forecasting.aemo.com.au/Electricity/MinimumDemand/Operational.

3. Network developments

This chapter summarises network investment activities since June 2018 that facilitate the integration of new renewable generation, and support Victorian power system security and reliability. These activities build on the nationally-optimised investment plan developed in AEMO's 2018 ISP.

Key network development insights

The energy landscape in Victoria is undergoing significant change. Strong investor interest in western parts of the state is shifting the geographic location of supply away from the Latrobe Valley, while increasing penetration of non-synchronous generation is changing the technical characteristics of the system. Overlaid on this, increasing adoption of DER is impacting the nature of demand, and raising new challenges associated with changes in flow directions and voltage control.

In response to these changes, and consistent with the findings of the 2018 VAPR, 2018 ISP, and 2018 *National Transmission Network Development Plan* (NTNDP), AEMO is:

- Progressing a RIT-T to reduce network congestion and potentially facilitate connection of additional generation in Western Victoria. AEMO intends to publish the Project Assessment Conclusions Report (PACR) in July 2019.
- Progressing a RIT-T to increase power transfer capability from Victoria to New South Wales, improving utilisation of renewable generation in the southern states, and supporting continued system reliability. AEMO intends to publish a PADR in the third quarter of 2019.
- Progressing a RIT-T to deliver additional reactive support in Victoria to alleviate voltage control issues at times of low demand. A PADR was published in June 2019 and identifies that 500 megavolt amperes – reactive (MVAr) of strategically placed reactive plant would deliver the highest net market benefits. Stakeholder submissions on the PADR close in August 2019.
- Addressing an identified gap for NSCAS through a short-term, six-month agreement for NMAS. This service provides voltage support during periods of low demand in the region. AEMO is also tendering for further interim NMAS services while the Reactive Power RIT-T progresses to deliver a long-term solution.

Neighbouring TNSPs are also experiencing similar challenges and are progressing their own investment projects that could impact flows within the Victorian DSN. These projects include development of:

- A second Bass Strait interconnector (Marinus Link) between Tasmania and Victoria, with a capacity of up to 1,200 MW. TasNetworks is currently progressing this through the first stage of the Project Marinus RIT-T.
- A new interconnector between South Australia and New South Wales (EnergyConnect), with a notional capacity of up to 800 MW. ElectraNet has concluded the RIT-T for this project, and is progressing with final regulatory approvals.
- For completeness, an update on the status of these projects has also been included in this chapter.

The following sections summarise the progress of key network development projects relevant to the DSN.

Chapter 4 provides more detail on the Victorian Planning methodology and other key inputs and assumptions used in Victorian RIT-Ts[42] and pre-feasibility/feasibility studies.

3.1 Western Victoria Renewable Integration RIT-T

The Western Victoria region is an attractive location for new renewable generation, due to the quality of local renewable energy resources, namely wind and solar. However, the transmission infrastructure in this region is insufficient to allow efficient access to new generation seeking to connect to it.

Around 2,000 MW of committed new renewable generation are expected to be built in the Western Victoria region by 2020. AEMO projects that a further 3,000 MW of new generation will be constructed in the region by 2025, based on proposed new connections and the Victorian Government's VRET[43].

In response, AEMO initiated a RIT-T process to assess the technical and economic benefits of increasing transmission network capacity in Western Victoria. In April 2017, AEMO published a PSCR that described the underlying need and the potential investment options available to address this need.

Following stakeholder consultation, in December 2018, AEMO published a PADR[44] to identify the preferred option. Stakeholder submissions closed in February 2019, and AEMO is preparing a PACR for release in July 2019.

Detailed information on this project can be found on the AEMO website[45].

The identified need

The identified need in the Western Victoria RIT-T is to increase the thermal capability of the Western Victorian power system, and thereby reduce constraints that would otherwise restrict new and existing generation. This will deliver market benefits (that is, an increase in consumer and producer surplus) through reductions in the capital cost and dispatch cost of generation over the long term.

The key emerging constraints covered by this RIT-T are the thermal constraints on the 220 kV Bulgana – Ballarat (via Crowlands, Ararat and Waubra) – Moorabool (via Elaine) path.

The preferred option

The PADR analysis identifies that the preferred option comprises:

- Construction of new double circuit 500 kV transmission line from Sydenham to Ballarat.
- Construction of a new 220 kV double circuit line from Ballarat to Bulgana.
- New wind monitoring and upgraded terminal station equipment that currently limits the thermal rating of 220 kV transmission lines at Red Cliffs to Wemen to Kerang, Bendigo to Kerang, Moorabool to Terang, and Ballarat to Terang.

This option, shown in Figure 7, carries the highest net market benefits when weighted across all reasonable scenarios, and under most sensitivities. The PADR estimates that the option delivers net market benefits of $80 million (in present value terms).

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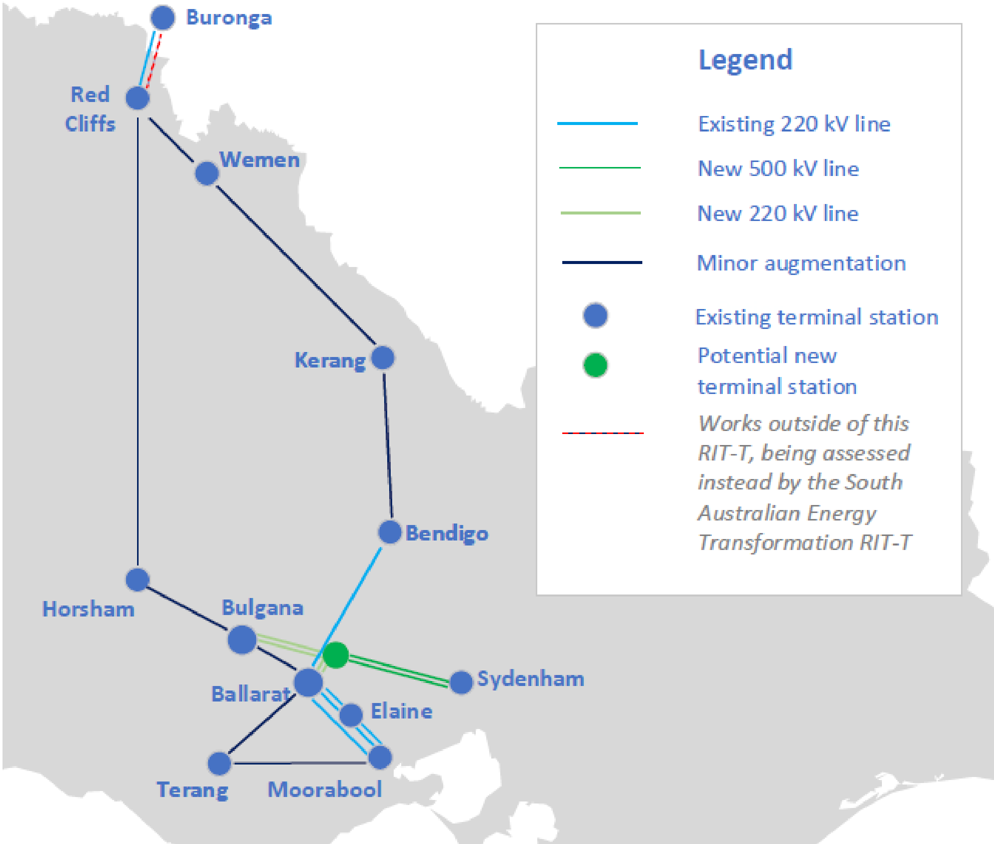
42 For more information about RIT-T projects and the RIT-T process, see the Australian Energy Regulator (AER) application guidelines, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018.

43 For details, see AEMO's Generation Information webpage, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Definitions of proposed and committed generation are under the Background Information tab in each regional spreadsheet on this webpage.

44 At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Western-Victoria-Renewable-Integration-RIT-T-PADR.PDF.

45 At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/RITT.

Figure 7 Preferred option – Western Victoria Renewable Integration RIT-T



The proposed timing for completion of the minor wind monitoring and terminal station upgrade works is 2021, while the proposed timing for delivery of the new lines is assumed to be 2025, subject to relevant easement acquisitions and planning/environmental approval processes.

Other credible options assessed

The RIT-T has considered all credible options and their combinations, including minor augmentations, new transmission lines (with different voltage levels and line routes), existing transmission line upgrades, and potential non-network options. See the PADR[46] for more information on the credible options considered.

3.2 Victorian Reactive Power Support RIT-T

Under minimum demand conditions, and without operator intervention, high voltages can occur on the Victorian transmission network. Short-term operational measures, such as network reconfiguration by de-energising transmission lines, have become necessary during these periods to maintain voltages within operational limits.

The frequency and severity of these voltage control interventions has increased rapidly, and continued reliance on such measures will result in higher market costs, reduced system resilience, and higher system security risks. Forecast reductions in minimum demand over the next 10 years will further exacerbate this issue.

[46] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Western-Victoria-Renewable-Integration-RIT-T-PADR.PDF.

In response, AEMO initiated a RIT-T process to assess the technical and economic benefits of delivering additional reactive power support in Victoria. In May 2018, AEMO published a PSCR[47] that described the underlying need and the potential investment options available to address this need.

Following stakeholder consultation, AEMO published a PADR[48] in June 2019 to identify the preferred option. Stakeholder submissions on this report are open until August 2019.

The identified need

The identified need in the Reactive Power RIT-T is to maintain voltages within operational and design limits during minimum demand periods, and to maintain the power system in a satisfactory and secure operating state. This investment will deliver net benefits through reduced market costs associated with operator intervention and non-market ancillary services over the long-term.

The key limiting locations covered by this RIT-T are network elements around Geelong, Keilor, Portland, and Moorabool due to lightly loaded transmission lines in the South-West corridor under low demand conditions.

The preferred option

The RIT-T analysis identifies that the preferred option comprises:

- Two 100 MVAr 220 kV reactors at Keilor Terminal Station.
- Two 100 MVAr 220 kV reactors at Moorabool Terminal Station.
- A single +200/-100 MVAr 330 kV synchronous condenser at South Morang Terminal Station.

This option carries the highest net market benefits when weighted across all reasonable scenarios, and is estimated to deliver net market benefits of $89 million (in present value terms). This option has an optimal staged investment timing between 2021 and 2023.

Other credible options assessed

The RIT-T considered all credible options and their combinations including, both static and dynamic plant types; and equipment of varying sizes, locations, and voltage levels. The RIT-T also considered possible non-network options, such as demand response, additional reactive capacity from grid-connected generators, and storage technologies.

Refer to the PADR for more information on the credible options considered and their relativities.

Addressing the interim need

The 2018 NTNDP identified that operator actions in response to high voltages in Victoria were becoming increasingly frequent and onerous, reducing system resilience, and potentially increasing system security risks.

The NTNDP declared this an NSCAS gap, and in March 2019, AEMO entered into a six-month NMAS agreement for voltage support services.

AEMO is currently tendering for additional reactive support services to take effect from September 2019[49], and is seeking proponents capable of absorbing at least 150 MVAr of reactive power on request, and primarily during low demand conditions. This service will be used to address the NSCAS gap while the Reactive Power Support RIT-T progresses to deliver a long-term network solution.

[47] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf.

[48] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

[49] At www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Invitation-to-Tender-for-NMAS-Reactive-Power-Support-in-VIC.

3.3 Victoria to New South Wales Interconnector (VNI) RIT-T

AEMO's 2018 ISP identified further development of the Victoria to New South Wales interconnector as a priority project. In particular, the ISP found that investment to increase transfer capability by approximately 170 MW would capture positive net market benefits through more efficient sharing of generation resources between states. This stronger interconnection could also help improve the reliability and resilience of the power system.

In mid-2018, AEMO and TransGrid jointly initiated a RIT-T to assess network and non-network options that are considered technically and economically feasible to increase Victorian transfer capacity to New South Wales. A PSCR[50] was published in November 2018 to describe the underlying need and potential investment options. Stakeholder submissions closed in February 2019, and AEMO is preparing a PADR for release in the third quarter of 2019.

The PADR will identify the preferred option for augmentation, quantify the expected net market benefits, and describe the optimal timing for investment.

The identified need

The identified need in the VNI RIT-T is to alleviate current and projected limitations on power transfer capacity from Victoria to New South Wales. An increased ability to share generation across this interconnector will deliver market benefits through improved system reliability and reductions in the capital cost and dispatch cost of generation over the long term.

Transfer capability between Victoria and New South Wales is currently limited by:

- Thermal capacity of the 500/330 kV transformer at South Morang.
- Thermal capacity of the 330 kV transmission circuits between South Morang and Dederang.
- Thermal capacity of the 330 kV transmission circuits between the Snowy Mountain area and Sydney.
- A Victorian transient stability limitation on transfers to avoid frequency instability.

In addition to the above limitations, there is also a new Victorian voltage stability limitation which can restrict transfers from Victoria to New South Wales during light load periods. This limitation was identified after the publication of the 2018 ISP and VAPR, and its market impact is being investigated through the RIT-T process.

Credible options being considered

The RIT-T is considering all credible options and their combinations, including minor augmentations, new and upgraded transmission lines, new transformers and reactive assets, and potential non-network options. While options that could be implemented quickly, and at a modest cost, are likely to deliver the highest net market benefits, several larger and longer-term options are also feasible and are being tested.

The VNI RIT-T attempts to address several competing network limitations to deliver a consistent increase in transfer capacity under a range of operating conditions. In particular, credible options may need to:

- Provide additional thermal capacity to the existing 500/330 kV transformation at South Morang:
  - Additional 500/330 kV transformer(s) in parallel with the existing South Morang F2 transformer.
  - Replacing the existing South Morang F2 transformer with a transformer of a higher capacity.
- Provide additional thermal capacity to the existing 330 kV circuits from South Morang to Dederang:
  - Uprating the South Morang – Dederang 330 kV lines by conductor re-tensioning and associated works (including uprating of series capacitors) to allow the line to run to thermal rating.
  - Additional 330 kV circuit(s) in parallel with the existing 330 kV South Morang – Dederang lines.

[50] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PSCR.pdf.

- Replacing the existing 330 kV South Morang – Dederang lines with higher capacity conductors.
- Improve stability:
  - Installing dynamic reactive plant (FACT devices) such as Static Var Compensation (SVC), STACOM, synchronous condensers, and any other equivalents. In addition, AEMO will investigate the impact of future network augmentations on the stability limits.
- Provide additional thermal capacity between Snowy and Sydney:
  - Uprating the existing Canberra – Upper Tumut 330 kV line.
  - Uprating the existing 330 kV lines between Snowy and Sydney (in addition to Canberra – Upper Tumut).
  - Additional 500 kV single circuit line between Snowy and Bannaby, bringing forward part of a 'Group 2' project in the ISP[51]. This is an alternative to uprating existing 330 kV lines between Snowy and Sydney.

3.4 ElectraNet's SAET RIT-T (Project EnergyConnect)

The South Australian Energy Transformation (SAET) is aimed at reducing the cost of providing secure and reliable electricity to South Australia in the near term, while facilitating a longer-term transition to low emission energy sources.

In November 2016, ElectraNet commenced a formal RIT-T to test the technical and economic feasibility of options to facilitate SAET[52]. Following extensive modelling and stakeholder consultation through the PSCR and PADR process, ElectraNet released a PACR[53] in February 2019 to conclude the RIT-T assessment. The Australian Energy Regulator (AER) is now required to review the RIT-T outcome and issue a determination in the coming months.

ElectraNet and TransGrid have now jointly launched 'Project EnergyConnect', to deliver the selected option from this RIT-T.

The selected option

The PACR concluded that a new 330 kV interconnector from Robertstown in mid-north South Australia via Buronga and through to Wagga Wagga in New South Wales would deliver the highest net market benefits. This option also includes an augmentation between Buronga in New South Wales and Red Cliffs in Victoria.

The project is expected to deliver market benefits through improved electricity affordability, improved network security, and the connection of renewable energy needed to meet federal and state carbon emissions targets.

Implications for Victorian DSN performance

In the following section, it is assumed that the selected option described above, and the preferred option proposed in AEMO's Western Victoria Renewable Integration RIT-T, will both be fully implemented.

Generally, Project EnergyConnect will improve the performance of the Victorian DSN, through the provision of stronger interconnection between Victoria, New South Wales, and South Australia. This will provide additional supply options, and network flexibility when managing DSN constraints.

However, the new interconnector will change flow patterns and network loadings within the system, potentially imposing additional pressure on existing DSN assets under certain operating conditions.

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[51] The 2018 ISP recommended developments in three groups: Group 1 to be completed as soon as practicable; Group 2 to be progressed immediately for implementation by the mid-2020s; and Group 3 in the longer term. Group 2 investments were focused on enhancing trade between regions, providing access to storage, and supporting extensive development of renewable energy zones (REZs). See the 2018 ISP at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf.

[52] For more information on the SAET RIT-T, see https://www.electranet.com.au/projects/south-australian-energy-transformation/.

[53]See https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf.

For example, high import to Victoria from EnergyConnect, combined with high levels of renewable generation in Western Victoria, may exacerbate monitored limitations on the 220 kV system between:

- Red Cliffs – Horsham.
- Horsham – Bulgana.
- Red Cliffs – Wemem – Kerang – Bendigo.
- Bendigo – Ballarat.
- Bendigo – Fosterville – Shepparton.
- Moorabool – Geelong – Keilor.
- Sydenham – Sydenham.

High export from EnergyConnect to South Australia, combined with low levels of generation in Western Victoria and the Latrobe Valley, could also result in increased import requirements from New South Wales, exacerbating limitations along the Murray – Dederang – South Morang and Dederang – Shepparton – Bendigo lines. See Section 4.4 for more information on AEMO's continued monitoring of network development needs between New South Wales and Victoria.

3.5 TasNetworks' Project Marinus RIT-T

The Australian Renewable Energy Agency (ARENA) and TasNetworks are currently assessing options for a second interconnector between Victoria and Tasmania (Marinus Link) as part of Hydro Tasmania's proposed Battery of the Nation project (Project Marinus)[54]. Several route options are being explored through the RIT-T process that would impact the Victorian transmission network.

In July 2018, TasNetworks published a PSCR on additional interconnection options between Victoria and Tasmania, as the first step of the regulatory process to examine the benefits of further electricity transmission between the two regions.

The PSCR notes that due to diversity in customer demand, generation, and storage resources between Tasmania and the rest of the NEM, an increase in interconnection capacity between the two has the potential to realise positive net economic benefits.

All credible options identified in the PSCR relate to the construction of an additional Bass Strait interconnector, with several different route options and two potential capacity levels (a new high voltage direct current [HVDC] interconnector 'pole' with capacity of approximately 600 MW, or two new 'poles' with capacity of 600 MW each).

Following the publication of the PSCR, TasNetworks published an Initial Feasibility Report[55] in February 2019. AEMO has not corroborated the report findings. The report finds that:

- Marinus Link would be technically feasible at a capacity of 600 MW, or at a capacity of 1,200 MW delivered in two 600 MW stages.
- Marinus Link is estimated to have a capital cost of approximately $1.3-1.7 billion for a 600 MW capacity interconnector and approximately $1.9-3.1 billion for a 1,200 MW capacity interconnector.
- The economic feasibility of Marinus Link varies with commissioning date, and will also depend on other assumptions made about future developments in the NEM.
- The largest factor in the economic feasibility and optimal timing of Marinus Link is expected to be the trajectory of coal-fired generation retirement in the NEM.

[54] Further information on the Marinus Link project including the proposed timelines can be found on TasNetworks Project Marinus website, at https://projectmarinus.tasnetworks.com.au/.

[55] See https://projectmarinus.tasnetworks.com.au/wp-content/uploads/2019/02/Initial-Feasibility-Report-Project-Marinus-Feb-2019.pdf.

- Under TasNetwork's high emission reduction scenario, the projected net economic benefit of Marinus Link is expected to be $490 million for a 600 MW link, and $480 million for a 1,200 MW link (built and commissioned in two stages) from the mid-2020s.
- Route options connecting the Latrobe Valley region of eastern Victoria and the Burnie or Sheffield areas of north-west Tasmania would be favourable, with work continuing to identify a preferred route. The Feasibility Report presents all credible route options being considered.

AEMO has conducted a high-level assessment of the impact that Marinus Link might have on the Victorian DSN if connecting in the Latrobe Valley. Preliminary studies indicate a connection at Loy Yang 500 kV or at Hazelwood 500 kV would have low impact given the existing local network infrastructure. Significant increases in power transfers between Victoria and Tasmania could put increased pressure on Victorian interconnection with other mainland states – potentially strengthening the case for further development of these flow paths.

4. Forecast limitations

This chapter describes emerging and monitored DSN limitations that impose constraints on power transfers or result in reduced ability to meet network performance requirements.

Key network limitation insights

While AEMO is already progressing a number of network development projects to address previously identified limitations, AEMO also continues to monitor the emergence of new limits – particularly those that may only become significant following an unexpected change in local demand, generator investment, or generator withdrawal.

While no new network limitations have been identified as triggering a formal economic assessment since the 2018 VAPR, several new limitations have been put on heightened monitoring. In particular:

- Post-fault voltage oscillation concerns have been identified in the north-west of Victoria under prior outage conditions. AEMO is currently managing this through normal operational limits advice and maintenance scheduling processes.
- The withdrawal of further thermal plant from the Latrobe Valley may result in supply shortfalls, system strength gaps, reactive power issues, or other consequential power system impacts. While participants are expected to provide adequate notice before decommissioning, there are risks that a substantial plant failure or force majeure event could cause an early or unexpected plant retirement.

  As a prudent risk mitigation strategy, AEMO has commenced preliminary studies on options to improve interconnection with New South Wales in the long term, unlocking additional renewables in Victoria and delivering reliability benefits in the event of future plant closures in the Latrobe Valley. AEMO expects to build on these studies to commence a formal RIT-T process in the near future.
- AEMO is undertaking detailed dynamic power system analysis to identify any current system strength gaps in Victoria, and those that may emerge over the coming five-year period. While no system strength gaps have yet been declared under system normal conditions, AEMO expects to publish a final report detailing investigation results by the end of 2019. AEMO, as the System Strength Service Provider (SSSP) for Victoria, would then act to address any declared gaps.
- AEMO is undertaking a review of control schemes in Victoria to ensure they remain optimally configured and fit-for-purpose as system operating conditions change.

4.1 Methodology

4.1.1 DSN augmentation planning approach

To identify network augmentation needs, AEMO first investigates transmission network limitations by:

- Reviewing historical network performance over the previous year and the periods that known constraints were binding.
- Reviewing future network performance under a range of demand and generation scenarios considering government policy and economic growth projections.

For any major transmission limitations identified, AEMO performs an exploratory study, using high-level economic assessment to identify the market benefits of relieving the transmission limitations.

AEMO undertakes joint planning with other TNSPs and Victorian DNSPs to address transmission limitations, challenges, and opportunities. Victorian joint planning outcomes have been incorporated into the limitation summaries presented in this chapter.

Appendix A3 has more information on AEMO's transmission network limitation review approach.

If positive net market benefits are identified as likely, AEMO initiates a pre-feasibility study, using detailed market modelling to assess the benefits from credible augmentation options. Depending on the scale of costs, if positive net market benefits are projected this pre-feasibility study may lead to a RIT-T.

This analysis provides signals for potential network and non-network development opportunities, such as localised generation or demand response.

For more detail on the DSN planning methodology, see AEMO's *Victorian Electricity Planning Approach*[56].

4.2 Completed projects and retirements

This section describes completed generation projects and retirements, which highlight the changing nature of the Victorian DSN and underpin the determination of new network limitations in this chapter.

4.2.1 Network upgrades

The following projects have been completed since publication of the 2018 VAPR:

- Wemen Terminal Station 2nd Transformer B2 220/66 kV was commissioned in October 2018.
- Murra Warra Terminal Station (Murra Warra Wind Farm 220 kV connection) was commissioned in February 2019.
- Bulgana Terminal Station (Bulgana Wind Farm 220 kV connection) was commissioned in February 2019.
- Crowlands Terminal Station (Crowlands Wind Farm 220 kV connection) was commissioned in September 2018.
- South Morang H2 Transformer replacement:
  - Replacement of the H2 transformer with a new 700 MVA 330/220 kV transformer, designated H3.
  - Existing H2 FERRANTI 330/220 kV transformer retained as a cold spare transformer.

4.2.2 New generator connections

The following generator connections have progressed since publication of the 2018 VAPR:

- The 90 MW Karadoc Solar Farm connected to the Victorian DSN in March 2019 via Powercor's network at Red Cliffs Terminal Station.
- The 54 MW Salt Creek Wind Farm connected to the Victorian DSN in July 2018 at Terang Terminal Station.
- The 55 MW Gannawarra Solar Farm connected to the Victorian DSN in October 2018 via Powercor's network at Kerang Terminal Station.
- The 88 MW Bannerton Solar Park, connected to the Victorian DSN via Powercor's network at Wemen Terminal Station, is undergoing commissioning testing.
- The 79.95 MW Crowlands Wind Farm, connected to the Victorian DSN between Ararat and Horsham s, is undergoing commissioning testing.

[56] AEMO, *Victorian Electricity Planning Approach*, 2016, at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Victorian-Electricity-Planning-Approach.

- The 132 MW Mt Gellibrand Wind Farm, connected to the Victorian DSN via Powercor's network between Terang and Geelong, is undergoing commissioning testing.
- The 225.7 MW Murra Warra Wind Farm Stage 1, connected to the Victorian DSN at Murra Warra Terminal Station, is undergoing commissioning testing.
- The 100 MW Numurkah Solar, connected to the Victorian DSN via Powercor's network at Shepparton Terminal Station, is undergoing commissioning testing.

The above list only considers large generation projects (greater than 30 MW capacity). There may be additional small generation projects embedded within the distribution network.

4.2.3 New storage connections

The following storage connections have occurred since publication of the 2018 VAPR:

- The 30 MW/30 megawatt hour (MWh) Ballarat Energy Storage System connected to the Victorian DSN in November 2018 at Ballarat Terminal Station.
- The 25 MW/50 MWh Gannawarra Energy Storage System connected to the Victorian DSN in November 2018 at Kerang Terminal Station.

4.2.4 Retirements

There have been no transmission network, generation, or storage retirements in the Victorian DSN since publication of the 2018 VAPR.

4.3 Future projects and opportunities

This section describes committed future generation projects and retirements, in addition to findings from AEMO's annual planning review of transmission network limitations in Victoria.

Information on committed future terminal station projects for connecting load or generation is also presented in this section. This is supported by AEMO's guidelines for establishing new terminal stations in Victoria[57].

4.3.1 Committed and potential generation projects

For generator transmission connections in Victoria, AEMO is involved in all stages of the connection process, from pre-feasibility to completion. For generator distribution connections, the connecting DNSP manages the connection process and is the main point of contact for the connection applicant.

Information on committed and potential generation projects over the next 10 years can be found on AEMO's generation information page[58], and AEMO's website also contains an information register on large (greater than 30 MW) generator connections[59].

Since the 2018 VAPR (and as at May 2019), the following generation projects have become committed projects, meaning that they have advanced to the point where proponents have secured land and planning approvals, entered into contracts for finance, and have either started construction or set a firm date:

- Solar (DSN connection) – Kiamal Solar Farm – Stage 1 (200 MW and 190 MVAr synchronous condenser).
- Solar (distribution connection) – Cohuna Solar Farm (27.27 MW), Wemen Solar Farm (87.75 MW), Yatpool Solar Farm (81 MW).

[57] AEMO, *Guidelines for Establishing Terminal Stations in Victoria*, 2011, at http://www.aemo.com.au/-/media/Files/PDF/0174-0018%20pdf.ashx.

[58] AEMO, Generation Information web page, at http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information. AEMO's commitment criteria for generation are published under the Background Information tab in each regional spreadsheet.

[59] AEMO, Register of large generator connections, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Register-of-Large-Generator-Connections.

- Wind (DSN connection) – Bulgana Green Power Hub – Wind Farm (194 MW), Dundonnell Wind Farm (336 MW), Moorabool Wind Farm (320 MW), Stockyard Hill Wind Farm (532 MW).
- Wind (distribution connection) – Cherry Tree Wind Farm (57.6 MW), Lal Lal Wind Energy Elaine end (83.6 MW), Lal Lal Wind Energy Yendon end (144.4 MW).
- Storage – Bulgana Green Power Hub – BESS (20 MW/34 MWh).

For intending connection applicants, the AEMO website contains information on AEMO's process for network connections[60], procedure for network augmentations to cater for new generation connections, and the data request approach for network data[61].

4.3.2 Committed transmission network projects and retirements

The following transmission projects meet the criteria for committed projects, having advanced to the point where proponents have secured land and planning approvals, entered into contracts for finance, and either started construction or set a firm date:

- Kiamal Terminal Station – this new 220 kV terminal station facilitating the connection of Kiamal Solar Farm is expected to be completed in late 2019.
- Haunted Gully Terminal Station – this new 500 kV terminal station facilitating the connection of Stockyard Hill Wind Farm is expected to be completed in late 2019.
- Dundonnell Terminal Station – this new 500 kV terminal station, connected to Mortlake Power Station and facilitating the connection of Dundonnell Wind Farm, is expected to be completed in late 2019.

Refer to Chapter 5 for information on the assessment process for potential transmission asset retirements.

4.3.3 Emerging development opportunities

The VAPR identifies opportunities to address transmission network limitations emerging over the next 10 years, where credible solutions are likely to deliver positive net market benefits.

Where possible, for each emerging transmission limitation, AEMO provides relevant transmission terminal station data, transmission line segment data, and new generator connections data in the supporting material, as required by the Transmission Annual Planning Report (TAPR) guidelines[62].

Emerging limitations identified in past VAPRs

The following emerging network limitations identified in the previous VAPRs are now being assessed or addressed through the RIT-Ts presented in Chapter 3. This includes:

- Ballarat – Waubra – Ararat – Bulgana 220 kV line and Ballarat – Elaine – Moorabool 220 kV line thermal limitation. Refer to Section 3.1 of the Western Victoria Renewable Integration RIT-T for more information.
- Greater Melbourne and Geelong area and south-west Victoria – maintain voltages within operational limits during minimum demand periods. Refer to Section 3.2 for more information.
- South Morang – Dederang 330 kV line and South Morang 500/330 kV transformer thermal limitation, Victorian export transient stability limitation, and voltage stability limitation. Refer to Section 3.3 for information about the Victoria to New South Wales Interconnector (VNI) RIT-T for more information.

New emerging network limitations

AEMO has conducted a combination of power flow modelling and economic assessments to identify any new network limitations (beyond those identified in the 2018 VAPR). These studies include the committed developments listed in Section 3.2, and sensitivities with and without the active network development projects

[60] AEMO, Network Connections web page, at http://www.aemo.com.au/Electricity/Network-Connections.

[61] AEMO, Policy on provision of network data web page, at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/Policy-on-Provision-of-Network-Data.

[62] At https://www.aer.gov.au/system/files/AER%20-%20TAPR%20guidelines%20and%20final%20decision%20-%2018%20December%202018.pdf.

identified above. While no newly identified limitations have triggered a formal economic assessment since the 2018 VAPR, several new limits have been put on heightened monitoring. These are discussed in the following section.

4.4 Monitored transmission limitations

AEMO continues to monitor transmission network limitations that may result in supply interruptions or constrain generation, but for which there is either no currently identified needs/triggers, or where there are not yet sufficient market benefits to justify the cost of relieving the limitation.

The full list of Victorian monitored transmission limitations can be found in Appendix A1. These limitations are not expected to significantly impact on the electricity market within the next five years, but may have an eventual impact, if specific generation, demand, or network changes occur.

For each monitored limitation, AEMO will continue to monitor the identified trigger conditions and progress network development projects if these become appropriate. AEMO also welcomes feedback from stakeholders where they consider that addressing a monitored transmission limitation would currently deliver enough market benefits to outweigh solution costs.

4.4.1 Near-term New South Wales to Victoria import limitation

The 2018 VAPR identified that Victorian import capabilities from New South Wales were an emerging development opportunity for Victoria. This import capability is constrained by thermal capacity limitations near Dederang, and by a voltage stability limitation that typically binds during periods of reduced availability of Murray generating units.

While there is a short-term driver to improve import capabilities into Victoria to support peak demand periods, this need is likely to erode quickly as new renewable generation is installed to meet renewable energy policy targets. In the long-term, Victorian import limitations become critical following closure of further coal-fired generators in the Latrobe Valley. The most recently published information indicates an expected staged retirement of Yallourn Power Station between 2029 and 2032[63].

AEMO has investigated the feasibility and economic merits of several short-term credible options, including seeking offers from potential service providers through a formal Expression of Interest and Invitation to Tender processes in late 2018. This process did not identify any suitable solutions that would pass an economic net-benefits test.

The VNI RIT-T, discussed in Section 3.3, does include potential thermal upgrade works that would improve import capabilities, and two currently proposed Network Capability Incentive Parameter Action Plan (NCIPAP) projects will also provide relief to these limitations. AEMO will continue to monitor the impact of these projects, and new renewable generation connections, on the frequency and severity of Victorian import limitations.

The identified need (near-term)

The identified need is to reduce thermal and voltage stability limitations that currently limit flows from New South Wales to Victoria. An increased ability to share generation across this interconnector would be expected to deliver market benefits through improved system reliability. This need is likely to erode over time as new renewable generation is connected in Victoria.

Transfer capability between New South Wales and Victoria is currently restricted by thermal limits on the:

- Murray – Dederang 330 kV lines.
- Dederang – South Morang 330 kV lines.
- Dederang – Mount Beauty – Eildon – Thomastown 220 kV transmission path.

[63] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Projects-Expected-Closure-Date.xlsx.

The Murray – Dederang 330 kV thermal limitation is expected to bind first under typical operating conditions. However, the South Morang – Dederang 330 kV line can be most limiting when temperatures in the Greater Melbourne and Geelong area are significantly higher than those in the Snowy region. These conditions contributed to events on 24 and 25 January 2019 (see Section 2.3 for a description of events on these peak demand days).

Victorian voltage stability limitations can bind ahead of these thermal limitations under some conditions, particularly during low availability of generation units in the Snowy region.

In the longer term, the 2018 ISP identified a need for large-scale network investment to strengthen transfer capabilities in both directions between Victoria and New South Wales. These projects are expected to deliver net market benefits following commissioning of the Snowy 2.0 generation project (for the northern network component), and following closure of additional Latrobe Valley generation (for the southern network component). See Section 4.4.2 for more information on AEMO's continued monitoring of these long-term needs.

Credible options assessed (near-term)

AEMO has investigated the feasibility of a number of short to medium options since publication of the 2018 VAPR. In particular:

- Procurement of network support services from industrial loads to allow operation of the Murray – Dederang 330 kV lines at a higher thermal rating.
  - This option has not been implemented, because the only effective industrial load is separately contracted, and would be unable to provide this service. AEMO may reconsider this option in the future if these contractual conditions change.
- Procurement of network support services from generators to increase the voltage stability import limit to Victoria from New South Wales.
  - This service would involve the provision of additional reactive support (injection). AEMO undertook Expression of Interest and Invitation to Tender processes with selected generators, however was not able to justify these network support services under a net-benefits test based on the market impact of the voltage stability limit. AEMO may reconsider this option if alternative options become available, or the market impact of the voltage stability limit changes.
- Network Augmentation options to increase the rating of the Dederang – South Morang 330 kV line.
  - As discussed in Section 3.3, the VNI RIT-T includes options to increase the thermal capacity between Dederang and South Morang. Both the import and export benefits of upgrading this line are being considered in the VNI RIT-T.

Other relevant projects that may reduce these limitations include:

- AusNet Services' NCIPAP project to install reactive power plant that can dynamically control the impedance of (and thus power flows across) the Jindera – Wodonga 330 kV line. This project is expected to increase the New South Wales to Victoria import capability by relieving both thermal and voltage stability constraints. This project is scheduled to be completed in 2019.
- TransGrid's 2019 NCIPAP update proposes the installation of a 100 MVAr capacitor at Wagga. This project would relieve the voltage stability limit affecting the New South Wales to Victoria import capability. Refer to TransGrid's 2019 Annual Planning Report for more information on this project.

In the longer term, larger network investment options may be required to strengthen transfer capabilities between New South Wales and Victoria. These needs, and AEMO's plans to address them, are discussed in more detail below.

4.4.2 Longer-term development between Victoria and New South Wales

AEMO has assessed the potential impact of longer-term developments, particularly with respect to increases in renewable generation and potential withdrawal of traditional thermal generation.

The 2018 ISP identified that large bi-directional capacity increases would be beneficial between New South Wales and Victoria by the early 2030s. These interconnector capacity increases have the potential to:

- Reduce network congestion and unlock new low-cost renewable generation projects in key renewable energy zones (REZs). See Section 6.3.1 for more information on REZs.
- Provide better access to pumped hydro storage and provide firmness for growing levels of intermittent renewable generation.
- Maintain reliability of supply in Victoria and New South Wales through diversity of supply sources.

In Victoria, the majority of market benefits are expected to coincide with the retirement of further coal-fired generation or declining reliability in the Latrobe Valley. Withdrawal of this plant may result in supply shortfalls, system strength gaps, reactive power issues, or other consequential power system impacts.

While participants are expected to provide adequate notice before decommissioning, there are risks that a substantial plant failure or force majeure event could cause an early or unexpected plant retirement.

The most recently published information indicates an expected staged retirement of Yallourn Power Station between 2029 and 2032[64]. However, as a prudent risk mitigation strategy, AEMO has already commenced preliminary technical studies on options that would improve transfer capability with New South Wales, and provide resilience against uncertain future step-changes in supply.

AEMO expects to build on these studies to commence a formal RIT-T process in the near future, to identify the most economic option to meet future interconnector needs with New South Wales.

4.5 Interim limitations and challenges

AEMO, through the VAPR analysis, has identified several transmission limitations that may impact the network in the interim period between now and delivery of the RIT-T projects discussed in Chapter 3. In addition, AEMO has identified potential challenges in operating some of the existing Victorian control schemes as the system conditions move outside their original design assumptions. AEMO's strategy for managing these interim limitations and challenges is described below.

Regional Victoria transmission limitations

Until the completion of the Western Victoria Renewable Integration RIT-T, it is anticipated that the following network limitations may require automatic control following a credible contingency during a period of high renewable generation in Western Victoria:

- High overloading of the Ballarat – Waubra 220 kV line for a credible contingency (Red Cliffs – Kiamal 220 kV line trip).
- High overloading of the Ballarat – Waubra 220 kV line for a credible contingency (Ballarat – Waubra – Ararat 220 kV line trip).
- Overloading of the Red Cliffs – Wemen – Kerang 220 kV line for a credible contingency (Ballarat – Waubra – Ararat 220 kV line trip).

AEMO is investigating the feasibility of using control schemes to manage these limitations. The new control schemes would aim to minimise the market impact of the above identified thermal limitations via potential post-contingent trip of generation in the local area.

[64] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Projects-Expected-Closure-Date.xlsx

Several NCIPAP projects have also been proposed to reduce the market impact of the above identified network limitations.

Voltage management during minimum demand periods

As outlined in the 2018 NTNDP[65], high voltages can occur in Victoria following credible contingencies, and in some cases under normal (pre-contingent) operation during minimum demand conditions.

Operational measures, such as de-energizing 500 kV lines, have been applied to maintain operating voltages during critical periods, however frequent use of these measures can reduce system resilience and pose additional power system security risks.

The Victorian Reactive Power Support RIT-T, described in Section 3.2, will deliver a long-term solution to address these voltage control issues. However, in the interim, an NSCAS gap exists for reactive support services.

In March 2019, AEMO entered a short-term contractual arrangement for NMAS to meet this need, and is currently tendering for further NMAS services to deliver support until the reactive RIT-T project concludes.

Existing Victorian control schemes

There are approximately 25 system protection or control schemes in operation across the Victorian DSN. These schemes allow the system to respond in an automated, predictable way when subjected to unusual operating conditions or credible contingencies. In turn, this allows the system to operate more efficiently, and with less pre-contingent restrictions.

While these schemes are thoroughly designed and tested before implementation, rapid changes to the typical operating conditions and complexity of the Victorian system are challenging some of the original design assumptions used when developing each scheme. For example, during the system separation event on 25 August 2018[66], the Emergency Alcoa Portland Tripping (EAPT) scheme operated as designed to separate South Australia and Victoria following detection of its trigger conditions. However, this scheme and its triggers were not originally designed to cater for the circumstances of this event.

AEMO has commenced a full review of Victorian control schemes to ensure that these remain efficient and fit-for-purpose as the system continues to evolve.

4.6 Impact of activities outside Victoria

This section considers the impact of border-adjacent developments in New South Wales and South Australia that have the potential to impact operation of the Victorian DSN. Projected increases in committed generation in the south-west of New South Wales will have a network impact, until the new South Australia to New South Wales interconnector is commissioned.

Approximately 1 GW of newly committed generation will go into service in south-west New South Wales by 2020. Much of this committed generation is located close to the Red Cliffs – Buronga component of the Victorian-New South Wales interconnector.

AEMO's assessment indicates that this increased generation could increase the severity of congestion in some areas, especially on the Red Cliffs – Wemen – Kerang line and the Red Cliffs – Buronga line. It is expected that some generation in the Western Victorian region may be constrained during periods of high generation output in the local area.

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[65] AEMO, *2018 National Transmission Network Development Plan*, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

[66] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

Commissioning of the new South Australia to New South Wales Interconnector (described in Chapter 3.4), will relieve congestion, and unlock additional supplies in south-west New South Wales and north-western Victoria.

AEMO will continue to closely monitor limitations in this area. Refer to Appendix A1 for more details.

4.7 System strength limitations

4.7.1 Victorian fault level review

AEMO power system analysis has identified that the short-circuit levels of the following terminal stations may exceed their limits under certain operating conditions within the next five years.

Rowville 220 kV

The short-circuit level has increased in 2018 due to updated impedance information following the South Morang H1 transformer replacement. As a result, the maximum single phase-to-ground short-circuit current for a fault at Rowville 220 kV could exceed limits.

Operational strategies are in place, and AEMO is working with AusNet Services to investigate the need for any further mitigation actions.

Thomastown 220 kV (Bus1 and Bus 3)

The short-circuit level has increased in 2018 due to updated impedance information following the South Morang H1 transformer replacement.

As a result, both the maximum three-phase and single phase-to-ground short-circuit current could exceed limits under some network configuration. However, the short-circuit levels at Thomastown 220 kV Bus 1 and Bus 3 can be managed within short-circuit level limits in the most common operational modes.

West Melbourne 220 kV and 66 kV

The maximum single phase-to-ground short-circuit current for a fault at West Melbourne 220 kV bus could exceed the short-circuit limit during the first three years of the current outlook period. In addition, the maximum three-phase short-circuit current for a West Melbourne 66 kV fault could exceed short-circuit limits in 2019-20 and 2020-21.

Operational strategies are in place, and AEMO is working with AusNet Services to investigate the need for any further mitigation actions. AusNet Services has also reviewed the risks associated with plant items at this terminal station and has planned remediation works to address these risks.

A committed project to replace the existing four 150 MVA 220/66 kV transformer units with three 225 MVA transformer units is expected to be completed in 2021-22. This project results in the forecast fault level decreasing to below its limit at both West Melbourne 220 kV and 66 kV.

Moorabool 220 kV

The short-circuit level has increased in 2018, due to new renewable generation connections in the Western Victoria area. As a result, the maximum single phase-to-ground short-circuit current for a Moorabool 220 kV fault could exceed the short-circuit limit.

Operational strategies are in place, and AEMO is working with AusNet Services to investigate the need for any further mitigation actions.

4.7.2 2018 *National Transmission Network Development Plan* (NTNDP)

The 2018 NTNDP[67] assessed the short-term system adequacy of the national transmission grid over the next five years, and identified the below findings for Victoria.

System Strength

In June 2018, AEMO published the *System Strength Impact Assessment Guidelines*[68], which detail the system strength assessment methods used to determine any adverse system strength impacts. The 2018 *System Strength Requirements and Fault Level Shortfalls* report[69] uses the concept of three-phase fault level to quantify regional system strength requirements.

Based on AEMO's system strength requirements and ISP projections, the Victorian grid meets the minimum system strength requirements under system normal conditions, and no system strength gaps have been declared. In addition, the 2018 ISP projections show that the expected minimum number of synchronous units online is consistent with minimum operating requirements.

AEMO is conducting detailed studies to review and refine the minimum requirement definitions, and to consider how this requirement might be impacted when 500 kV lines are switched out of service for voltage control purposes. AEMO plans to publish an update of the minimum system strength requirement at the end of 2019.

AEMO, as the SSSP for Victoria, will continue to monitor and take action to address any declared system strength shortfalls.

Voltage oscillation in north-west Victoria

AEMO power system studies have confirmed that under some credible outage conditions in the north-west of Victoria, a subsequent credible contingency event can cause undamped voltage oscillations with the potential to impact system security. To prevent this, AEMO applies constraints to generation in the local area while network outages are in effect. AEMO recently released a communique[70] describing the need for, and application of, these constraints during planned outages.

While the VAPR planning process is designed to capture emerging stability limits, the newly identified voltage stability issues only manifest with multiple concurrent network elements out of service. This is typically beyond the scope of standard planning assessments. In addition, AEMO has been able to adequately reschedule planned outages to lower impact times, and resolve security concerns using dispatch constraints. Together, the low probability of multiple outages coupled with the availability of operational solutions means that network development options are unlikely to be economic.

However, AEMO is investigating potential control scheme mechanisms that may further reduce the impact of these limitations. AEMO will also continue to monitor trends in these limitations, which over time may change the need for network investment through the planning process. Appendix A1 provides more details.

Credible contingency size

In Victoria and New South Wales, new contingencies have been identified that would require disconnection or runback (i.e. reduction of MW output) of multiple renewable generating units in areas where generators are connected radially or are disconnected simultaneously due to special protection schemes.

During times of high wind generation in Victoria, this runback could represent a significant loss of generation, and could approach the largest single contingency in the Victorian system. Such large contingencies may

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[67] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

[68] AEMO, System Strength Assessment Guidelines, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

[69] AEMO, System Strength Requirements, at www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[70] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Planned-outages-in-the-North-Western-VIC-and-South-West-NSW-transmission-network-industry-communique.pdf.

require implementation of new operational constraints, including considerations such as voltage stability, transient stability, thermal limitations, and the availability of frequency control ancillary services (FCAS).

Network Support and Control Ancillary Services (NSCAS)

The 2018 NTNDP identified that operator actions in response to high voltages in Victoria were becoming increasingly frequent and onerous, reducing system resilience, and potentially increasing system security risks. The NTNDP declared this an NSCAS gap for voltage control in Victoria, and AEMO subsequently entered into a short-term, six-month NMAS agreement for reactive support services in March 2019.

AEMO is currently tendering for additional reactive support services from September 2019[71], and is seeking proponents capable of absorbing at least 150 MVAr of reactive power on request, and primarily during low demand conditions. This service would be used to address the NSCAS gap while AEMO's Reactive Power RIT-T progresses to deliver a long-term network solution (see Section 3.2).

4.8 Distribution planning

AEMO reviews DNSPs' plans for existing and new connection points, and incorporates the general impact of distribution network modifications (including load changes and network configuration changes). AEMO and DNSPs work together to resolve connection asset limitations (for example, by installing additional transformers at existing connection points, or by establishing new connection points). This ensures a co-optimised and efficient solution for both the distribution network and the DSN.

Appendix A2 includes information on constraints and augmentations identified in the Victorian DNSPs' *2018 Transmission Connection Planning Report* as proposed by the Transmission Annual Planning Report Guideline.

[71] At www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Invitation-to-Tender-for-NMAS-Reactive-Power-Support-in-VIC.

5. DSN asset retirement, derating, and replacement

This chapter addresses NER requirements related to DSN asset retirement, deratings, and replacement, and has also modelled how possible future scenarios may affect existing asset utilisation.

Key asset replacement insights

While previous chapters have focused on the need for network augmentation, appropriate maintenance of Victoria's existing network asset base remains critical. In 2019, AEMO has again worked closely with AusNet Services to assess the need and economic justification for the replacement, refurbishment, derating, or retirement of existing assets that are approaching end-of-life.

In the 2019 VAPR:

- AusNet Services' 2019 asset replacement and refurbishment plans are largely consistent with those presented in the 2018 VAPR.
- Several new asset replacement projects have been identified, or have now moved within the assessment horizon, including:
  - Circuit breaker requirements at the Moorabool Terminal Station associated with the local transformers and 220 kV shunt reactors.
  - Circuit breaker replacement at the Rowville Terminal Station associated with the local SVC and capacitor bank.
- For each project, AEMO has analysed future system needs and confirmed the underlying system impact that would arise if the existing asset was removed without replacement. This analysis identified a continuing system need associated with each proposed asset replacement project.
- For the first time, AEMO has also included a sensitivity analysis on the impact of future generation plant withdrawals on existing assets in the Latrobe Valley. This is important because, although the traditional focus of network planning has been to support growing consumer demand, further generation plant withdrawals from the Latrobe Valley will change the utilisation of existing network assets, and may open opportunities for new local generation and interconnection projects. These changes will greatly impact the economic signals that underpin network asset replacements.

5.1 Rule requirements

Due to aging transmission assets, changes in technology, and slowing demand growth, there is an increasing need to coordinate DSN asset renewal and augmentation activities in Victoria, and to assess both the system need and economic justification for replacement of existing assets.

In Victoria, AusNet Services is responsible for assessing the condition of its Victorian DSN assets, and for making replacement, retirement, or derating decisions for these assets.

As the Jurisdictional Planning Body (JPB) for Victoria, AEMO's involvement is primarily in providing planning advice to AusNet Services (particularly on the continued system need for individual DSN assets). Under NER clause 5.12.12, regional TAPRs must include detailed information relating to all network asset retirements and deratings that would result in a network constraint over the planning period. AusNet Services' current asset renewal plan is available alongside the VAPR on the AEMO website[72].

Under NER clause 5.14A, where there is an identified need to retain an asset, AEMO and AusNet Services conduct joint planning to identify the most efficient and economic option to address the identified need. The following sections provides more information about the joint planning process for asset retirement, replacement, refurbishment, and deratings.

5.2 Joint planning of asset retirements and deratings

5.2.1 Methodology

AEMO and AusNet Services agreed an approach for joint planning which was adopted in this VAPR:

- AEMO and AusNet Services jointly selected a set of assets which are included in AusNet Services' Asset Renewal Plan and are likely to create a DSN constraint which potentially justifies a RIT-T for replacement.
- The selected assets were grouped with their associated network components whenever possible, and a need assessment was conducted by assessing the overall network impacts of retiring the asset. Circuit breakers, other switchgear, and secondary systems were grouped with their respective associated network components, such as transmission circuits, transformers, generators, or reactive plant. For example, if a line circuit breaker is retired, then its associated transmission circuit should also be considered as unavailable for service in assessing the system impact of the circuit breaker retirement.
  - Committed projects, transmission assets that do not form part of the DSN, and most secondary equipment were excluded from the network need assessment.
  - Assets proposed for retirement after 2026 were also excluded from the need assessment, due to uncertainties impacting retirement decisions in that timeframe.
- AEMO undertook an initial desktop analysis, and if required, further analysis, to assess whether the retirement of the selected asset would result in a network impact (that is, a network need for its replacement).

  In the case of an asset retirement causing disconnection of a generator, the resulting reduction in supply availability was considered.

  If the proposed retirements would cause line, transformer, or SVC outages, the impact of a credible contingency under worst-case operational conditions (normally either maximum or minimum demand conditions) was examined with a prior outage of the respective network element.

5.2.2 Needs assessment results

Table 7 below presents the summarised findings from the assets needs assessment.

[72] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Annual-Planning-Report.

Table 7 Network need assessment results

Project name	Location	Total cost (real $M)	Target completion	Major assets components	Retirement outcome
Horsham SVC Controls and Protection Replacement	Horsham	18	2023	Horsham 220 kV SVC	Voltage cannot be maintained within limits. Reduced Murraylink export during outage of Western Victorian 220 kV lines.
Moorabool Terminal Station Circuit Breaker Replacement (Eight 500 kV circuit breakers, nine 220 kV circuit breakers)	Moorabool	30	2024	Moorabool – Tarrone 500 kV No. 1 line and Moorabool – Sydenham 500 kV No. 1 line breaker-and-half switch bay	Reduced reliability caused by system separation due to a single credible contingency
				Moorabool – Mortlake 500 kV No. 2 line and Moorabool – Sydenham 500 kV No. 2 line breaker-and-half switch bay	Reduced reliability caused by system separation due to a single credible contingency
				Moorabool 500/220 kV A1 transformer double-breaker switch bay	Reduced reliability and capability to meet peak demand
				Moorabool – Ballarat 220 kV No. 1 and Moorabool – Terang 220 kV line breaker-and-half switch bay	Western Victorian generation constrained and reduced reliability. Reduced reliability caused by partial loss of terminal station due to a single credible contingency
				Moorabool 220 kV shunt reactor	Voltage cannot be maintained within limits.
				Moorabool 500/220 kV A1 transformer and Moorabool – Geelong No. 2 line breaker-and-half switch bay	Reduced reliability and capability to meet peak demand
				Moorabool 500/220 kV A2 transformer and Moorabool – Geelong No. 1 line breaker-and-half switch bay	Reduced reliability and capability to meet peak demand
South Morang 330/220 kV Transformer Replacement - Stage 2 (One 700 MVA 330/220 kV transformer)	South Morang	35	2024	South Morang 330/220 kV H1 transformer	Reduced reliability and capability to meet peak demand
Loy Yang Power Station and Hazelwood 500 kV Circuit	Loy Yang PS and Hazelwood	35	2024	Loy Yang – Hazelwood 500 kV No. 1 line double breaker switch bay	Generation constraints and reduced reliability

Project name	Location	Total cost (real $M)	Target completion	Major assets components	Retirement outcome
Breaker Replacement Stage 2 (14 circuit breakers)				Loy Yang 500 kV A2 Generator transformer double breaker switch bay	Loss of 530 MW of generation
				Loy Yang 500 kV A3 Generator transformer double breaker switch bay	Loss of 560 MW of generation
				Loy Yang 500 kV B2 Generator transformer double breaker switch bay	Loss of 500 MW of generation
				Hazelwood – Loy Yang 500 kV No. 2 Line and Hazelwood – Rowville 500 kV No. 3 line breaker-and-half switch bay	Generation constraints and reduced reliability
				Hazelwood – Loy Yang 500 kV No .3 Line and Hazelwood – Cranbourne 500 kV No. 4 line breaker-and-half switch bay	Generation constraints and reduced reliability
Rowville 220 kV Circuit Breaker Replacement	Rowville	6	2025	Rowville – Springvale 220 kV line No. 2 and Rowville No. 1 SVC breaker-and-half switch bay	Reduced reliability caused by loss of terminal station due to a single credible contingency. Reduction in interconnector capabilities.
				Rowville 500/220 kV A1 transformer No. 2 and Rowville No. 2 SVC breaker-and-half switch bay	Reduced reliability and capability to meet peak demand. Reduction in interconnector capabilities.
				Rowville No .3 capacitor bank breaker	Reduced maximum supportable demand caused by reduced reactive power margin[A].
Sydenham 500 kV GIS Replacement	Sydenham	25	2025	TBA	Reduced reliability caused by system separation due to a single credible contingency and reduction in interconnector capabilities
South Morang 500 kV GIS Replacement	South Morang	25	2026	TBA	Reduced reliability and interconnector capabilities

A. In the process of preparing this year's VAPR, AEMO carried out a limited set of load flow studies, focused on voltage levels, and has not identified low voltage constraints. Previous stability analysis confirmed the in-service 220 kV cap banks affecting maximum supportable demand. Further studies would be required to confirm if retirement of a 220 kV cap creates voltage stability constraints.

5.3 Latrobe Valley asset utilisation sensitivities

The changing generation mix in Victoria is having an impact on the typical operation and performance of the DSN, particularly since the closure of Hazelwood Power Station in March 2017. As further Latrobe Valley units retire, and more renewable generation is commissioned outside the Latrobe Valley, the utilisation of existing assets will continue to change. This will have a profound impact on the economic signals for existing asset replacement, refurbishment, derating, and retirements.

These impacts are not simple to project, for example:

- Retirement of further coal-fired generation in the Latrobe Valley would decrease local asset utilisation, and reduce the case for replacement investment.
- The potential future connection of new generation sources (including offshore wind projects), or new interconnector projects (such as Marinus Link), could increase reliance on existing Latrobe Valley assets.

Uncertainty around the timing, probability, and scale of these competing drivers means that any decision to de-rate or retire existing assets must be analysed carefully.

The sections below present the results of high-level analysis that tests the asset utilisation impact of network and supply changes in the Latrobe Valley. Further detailed power system and market modelling analysis would be required to quantify and value the implications for asset replacement planning.

5.4 Scenario study – Latrobe Valley retirements

AEMO publishes an expected closure date/year for all scheduled and semi-scheduled generators in the NEM, as advised directly by market participants[73]. This information was last updated on 11 June 2019, and indicates an expected closure profile for Yallourn Power station between 2029 and 2032, and for Loy Yang Power Station between 2047 and 2048.

For the indicative purposes of this section, AEMO has modelled the asset utilisation impacts of a full Yallourn Power Station retirement on the existing power system with all known committed projects included, and during a high-demand snapshot.

The modelling considered:

- Two alternative network configurations.
  - Retirement of Yallourn Power Station with the Latrobe Valley 500 kV and 220 kV networks operated radially at high demand.
  - Retirement of Yallourn Power Station with the Latrobe Valley 500 kV and 220 kV networks operated in parallel at high demand.
- Sensitivity results for the retirement of a Loy Yang generating unit, and the connection of a large new supply source (equivalent to large-scale generation, or a new interconnector project).

These studies found that the retirement of large-scale generation in the Latrobe Valley will significantly change local asset utilisation:

- In some cases, generation retirements in the Latrobe Valley are projected to increase pressure on existing assets, such as transformers in the Melbourne metropolitan area. This may require network reconfiguration, or network augmentations. AEMO will continue to monitor the emergence of these network needs through its network planning processes.
- In other cases, the modelled retirements are projected to reduce system reliance on existing assets and shift economic signals towards derating or retiring these assets. However, retaining these assets could also

[73] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Projects-Expected-Closure-Date.xlsx.

provide opportunities for new generation or interconnection projects to take advantage of existing infrastructure.

5.4.1 Latrobe Valley 500 kV and 220 kV networks operated radially

Assuming retirement of Yallourn Power Station, with the Latrobe Valley 500 kV and 220 kV networks operated radially at high demand, power system studies projected:

- Increased loading on the transformers in the Melbourne metropolitan area above their capacity, in particular, the Rowville Terminal Station (ROTS) A1 500/220 kV and the South Morang Terminal Station (SMTS) H2 330/220 kV transformers under system normal conditions, and further overloading of the Cranbourne Terminal Station (CBTS) A1 500/220 kV.
- Increased loading on the South Morang Terminal Station to Thomastown Terminal Station (TTS) No. 2 line above its capacity under system normal conditions.
- Increased loading on the Keilor Terminal Station (KTS) to Thomastown Terminal Station (TTS) No. 1 line and the SMTS H1 330/220 kV transformer above their capacity, under contingency conditions.

If the ROTS to Yallourn Power Station (YPS) and the ROTS to Hazelwood Power Station (HWPS) 220 kV lines are also retired, and the 220 kV bus at ROTS made solid, the projected results also include:

- Overloading on the CBTS A and SMTS H2 transformers, and the SMTS–TTS No. 2 line, increasing even further than above.
- Removal of the overloading of the ROTS A1 transformer, because the load at ROTS would be evenly shared between the two 500/220 kV transformers at ROTS due to the solid 220 kV bus arrangement.

Sensitivity – connection of a large new supply source at Yallourn Power Station

Modelling indicates that a 1,200 MW connection at YPS (equivalent to the largest Marinus Link interconnection option currently being considered) could allow the Latrobe Valley 500 kV and 220 kV networks to be operated radially without overloading of the ROTS A1 and SMTS H2 transformers and the SMTS–TTS No. 2 line. This would also remove the overload on the existing HWPS–YPS lines.

5.4.2 Latrobe Valley 500 kV and 220 kV networks paralleled

Assuming retirement of Yallourn Power Station, with the Latrobe 500 kV and 220 kV networks operated in parallel at high demand, power system studies project:

- Increased loading, under contingency conditions, on the HWPS–YPS No. 1 and No. 2 lines above their capacity, which may require a third HWPS–YPS line to be built.
- A need for the HWTS 500/220 kV transformation to be retained, although there may be potential for the number of transformers to be reviewed.
- Reduced overloading of the ROTS A1 and SMTS H2 transformers and the SMTS–TTS No. 2 lines, compared with that projected in radial mode.

5.4.3 Retirement of a Loy Yang generator unit

Power flow studies indicate that the retirement of a Loy Yang generator unit is not projected to create new thermal constraints on existing assets, however, it could reduce utilisation of the 500 kV lines from Loy Yang Power Station to Hazelwood Power Station.

In the absence of further local generator connections or new interconnection projects, this would put downward pressure on the need to invest in these assets.

Sensitivity – connection of a large new supply source at Loy Yang

At times of high demand, and with radial operation of the Latrobe Valley 500 kV and 220 kV networks, connection of a new 1,200 MW supply source to Loy Yang Power Station is projected to further exacerbate overloading of the CBTS A1, ROTS A1, and SMTS H2 transformers, and the SMTS–TTS No. 2 line.

If the Latrobe Valley 500 kV and 220 kV networks were paralleled, these overloads could be reduced, but may result in an overload on the existing 220 kV HWPS–YPS lines.

5.4.4 Comparison of asset utilisation duration curves

As explored in the previous sections, the maximum utilisation of different assets can change dramatically depending on generation retirements, network configuration, and new connections. The market impact of asset overloads depends on the length of time they are likely to occur.

The utilisation duration curves presented in this section were obtained by using an hourly supply demand balance, with standard profiles for wind and solar generation, historical profiles for hydro generators and interconnectors, and with the remaining load supplied by coal and gas generators. Network loadings were apportioned based on the impedance of the elements.

AEMO developed utilisation duration curves for the following cases:

- Case 1 – Yallourn Power Station remains in service.
- Case 2 – Yallourn Power Station retired, the Latrobe Valley 500 kV and 220 kV networks operated radially.
- Case 3 – Yallourn Power Station retired, the Latrobe Valley 500 kV and 220 kV networks paralleled with a third HWPS–YPS 220 kV line built and two 500/220 kV transformers in service at HWTS.

Figure 8 shows that under case 2, the ROTS A1 transformer is projected to overload more than 20% of the year.

Figure 8 ROTS A1 Transformer load duration curve

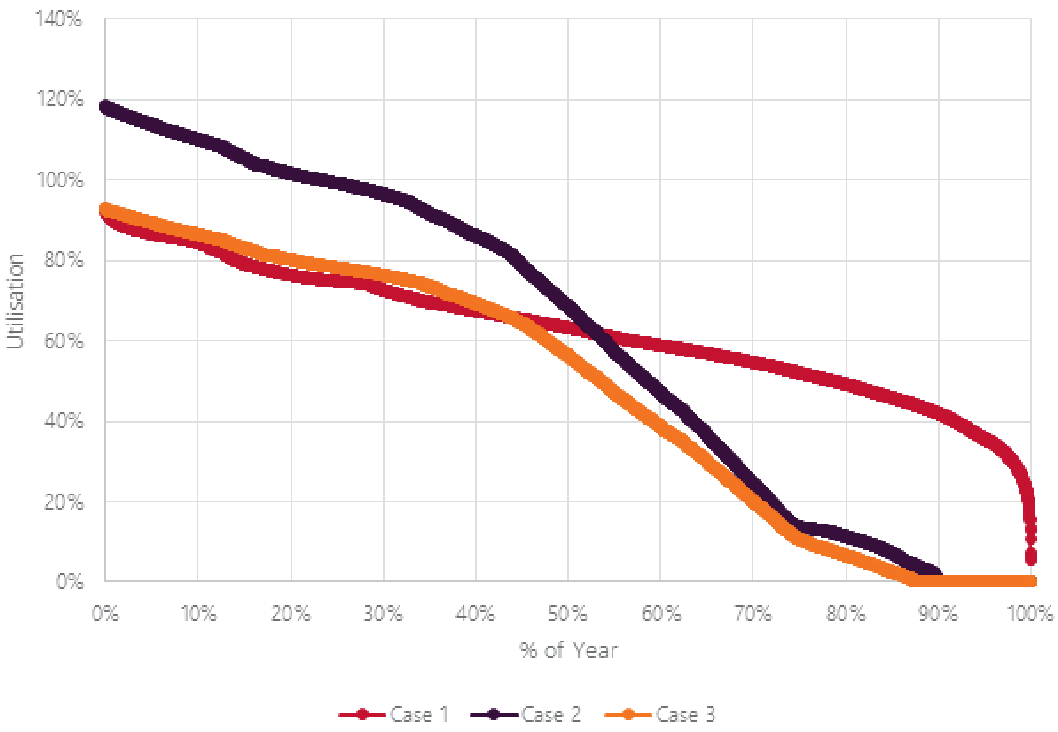
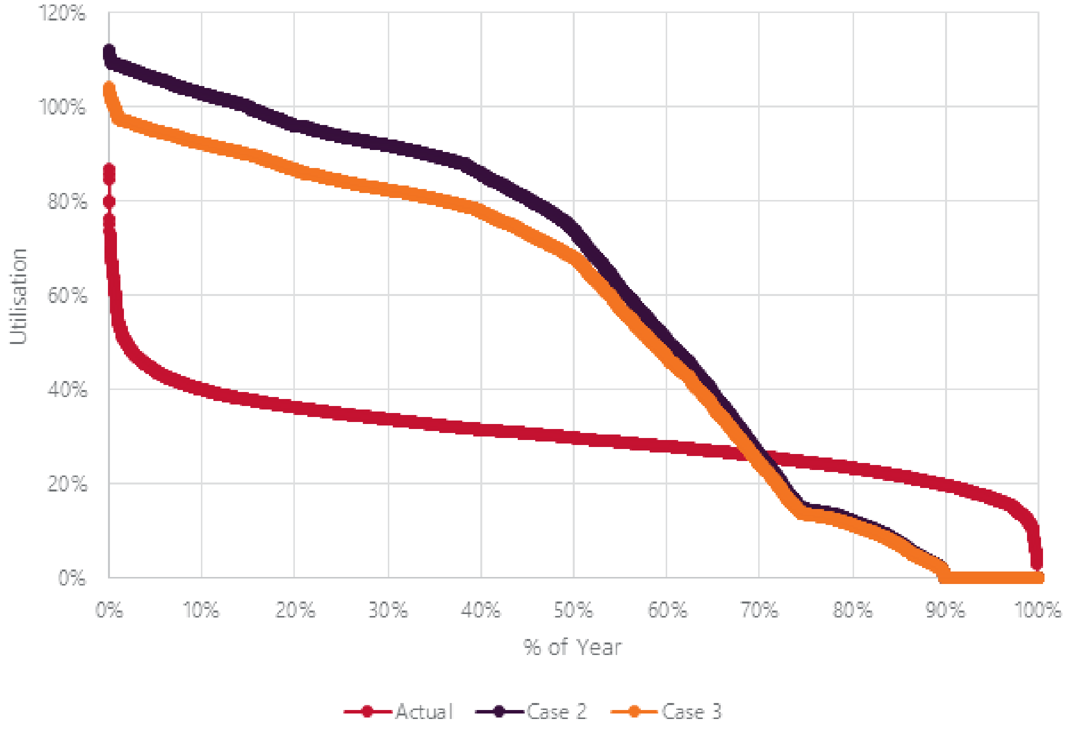


Figure 9 shows that the SMTS H2 transformer is projected to overload more than 20% of the year under case 2.

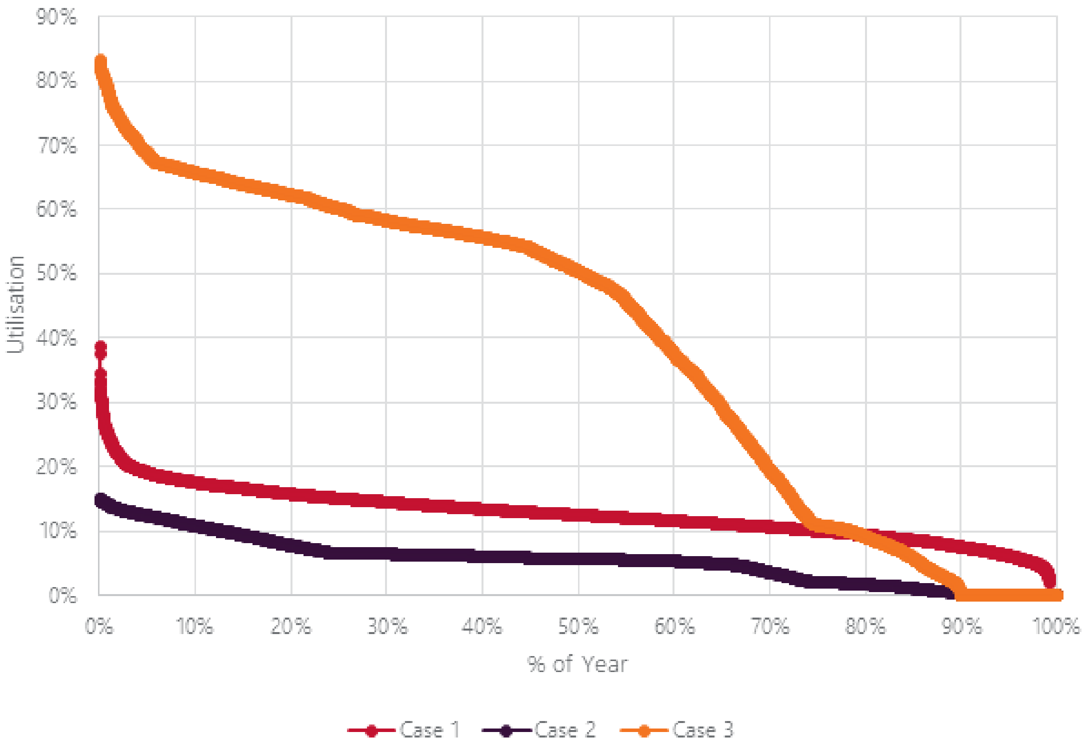
Figure 9 SMTS H2 Transformer load duration curve



Under case 2 assumptions, the utilisation of the HWTS transformers is projected to be low. However, other assets would be overloaded under system normal.

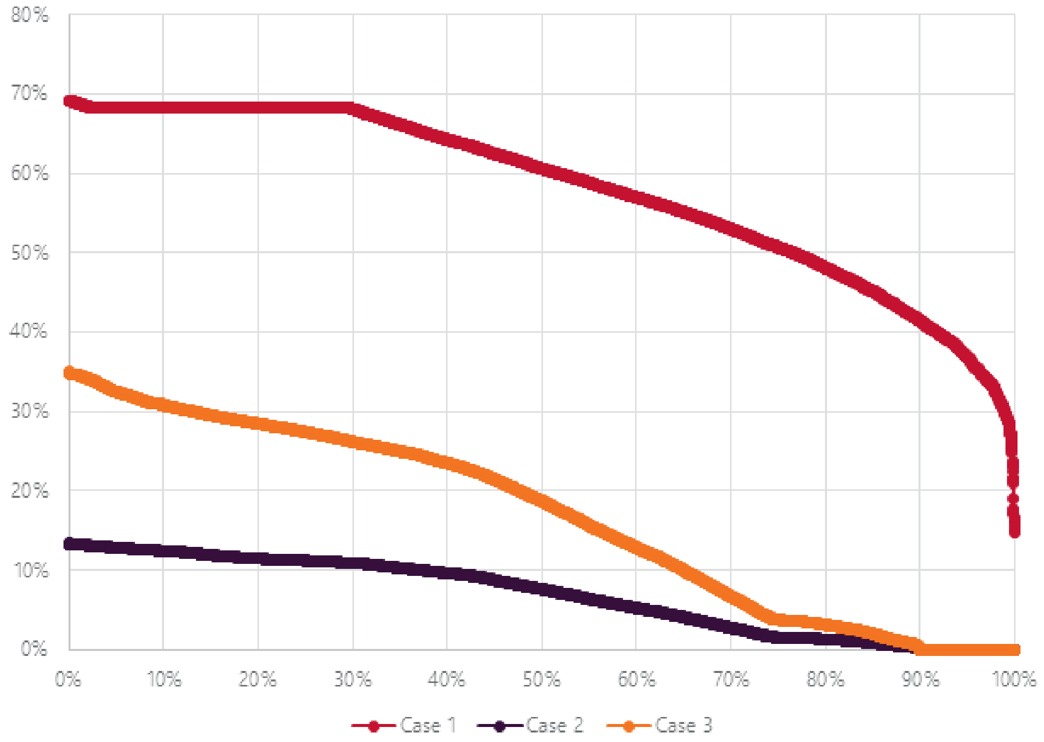
Figure 10 shows that under case 3 assumptions, the utilisation of the HWTS transformers could increase to up to 85%. As indicated in the previous two figures, any overloading of the ROTS A1 Transformer and SMTS H2 Transformer would likely be removed with this network configuration.

Figure 10 HWTS A4 Transformer load duration curve



The utilisation of ROTS to YPS lines is projected to reduce considerably following retirement of the Yallourn Power Station, as shown in Figure 11. Even under case 3, with the 500 kV and 220 kV networks paralleled, utilisation is projected to remain below 40%.

Figure 11 ROTS–YPS load duration curve



5.5 Impact on voltage control

Synchronous plant, such as the Yallourn and Loy Yang power stations, traditionally provide reactive power capability that assists the system to maintain secure voltage levels. If such plant were to retire, the level of available reactive power capability would be reduced, resulting in a more challenging power system to operate and higher system security risks associated with overvoltage excursions.

Replacing Latrobe Valley synchronous generation capacity with increased HVDC interconnection is unlikely to provide an equivalent level of reactive capability, and further network investment (such as through AEMO's Reactive RIT-T described in Section 3.2), may be required to ensure sufficient reactive absorption and injection capabilities are available. Alternatively, connection of offshore wind to the Latrobe Valley, with appropriate technology and reactive capabilities, could provide some level of replacement voltage support.

6. Connection insights

This chapter provides information and resources to help new and intending participants better understand the locational signals and changing investment landscape in Victoria.

Investment in new renewable generation in Victoria is growing at an exponential rate. This trend has been driven by the decline in renewable technology costs and supported by renewable policies, notably the Victorian Government's plan to deliver on a VRET of 50% renewable energy generation by 2030. At the same time, many coal-fired generators in the NEM are approaching their end of technical life in the next 20 years and withdrawing from the power system, as Hazelwood Power Station in Victoria did in 2017.

The rapid surge in renewable generator connections is driving a fundamental change in the behaviour of the Victorian power system, as the generation fleet transitions from traditional synchronous generation (coal and gas) to variable non-synchronous generation. As well as providing critical energy production and dispatchable power, conventional generators have traditionally been relied on to provide essential grid security services, such as system strength and inertia.

Areas of interest for the quality of their renewable fuel sources (such as north-west Victoria) are often parts of the network that have not been designed to accommodate large volumes of generation. Some renewable generator technologies are also not robust enough to withstand the technical characteristics associated with these weak network areas.

Locational signals are integrated in the NEM design, and are intended to guide developers to invest in areas that promote the most cost-effective outcome for consumers. Some investors in Victoria are already facing unexpected economic impacts and technical challenges associated with connection to weak transmission network, including:

- Thermal limitations – high volumes of renewable generation in the west of the state is leading to significant network congestion, resulting in the constraint of generator outputs.
- Stability limitations – the technical characteristics of wind and solar generation can contribute to reduced network stability, such as the identified risk of undamped voltage oscillations in western Victoria. Generator restrictions are necessary during outage conditions to mitigate the risk of system interruptions or collapse in the region.
- System strength – as new renewable generators connect to weak areas of the network, these generators face additional constraints and considerable remediation investment costs or delays.
- MLFs – increased power flows from new renewable generators in western Victoria to load centres is resulting in growing network losses and reduced MLFs for some generators in western parts of the state. As MLFs are applied to generator payments, lower MLFs result in reduced generator revenue.

Significant augmentation projects are already underway to deliver reduced network congestion, and unlock opportunities for more efficient use of renewable resources in Victoria.

Beyond investment in network infrastructure and market services, the growing complexity of power system requirements places additional pressure on investors to understand locational signals, technical standards, and connection processes that can have material impacts on projects' timing and viability.

6.1 Connection trends in Victoria

6.1.1 Victoria's generation mix

The Victorian generation fleet has traditionally been made up of coal- and gas-fired generation, with the state's current capacity composed 40% of coal-fired and 21% of gas-fired generation. This mix is changing rapidly as the state transitions to higher levels of renewable energy, with installed renewable capacity now rivalling coal at 38%[74]. This transition will continue. Figure 12 illustrates Victoria's existing generation capacity, along with committed and proposed new developments. All data provided in this section is as at 10 May 2019, and available on AEMO's Generation Information webpage[75].

Since the 2018 VAPR was published, 333 MW of new solar, 492 MW of new wind, and 55 MW of new battery storage technology has been built and commenced commissioning in Victoria[76].

Figure 12 Existing, committed and proposed large-scale generation capacity in Victoria, as at 10 May 2019

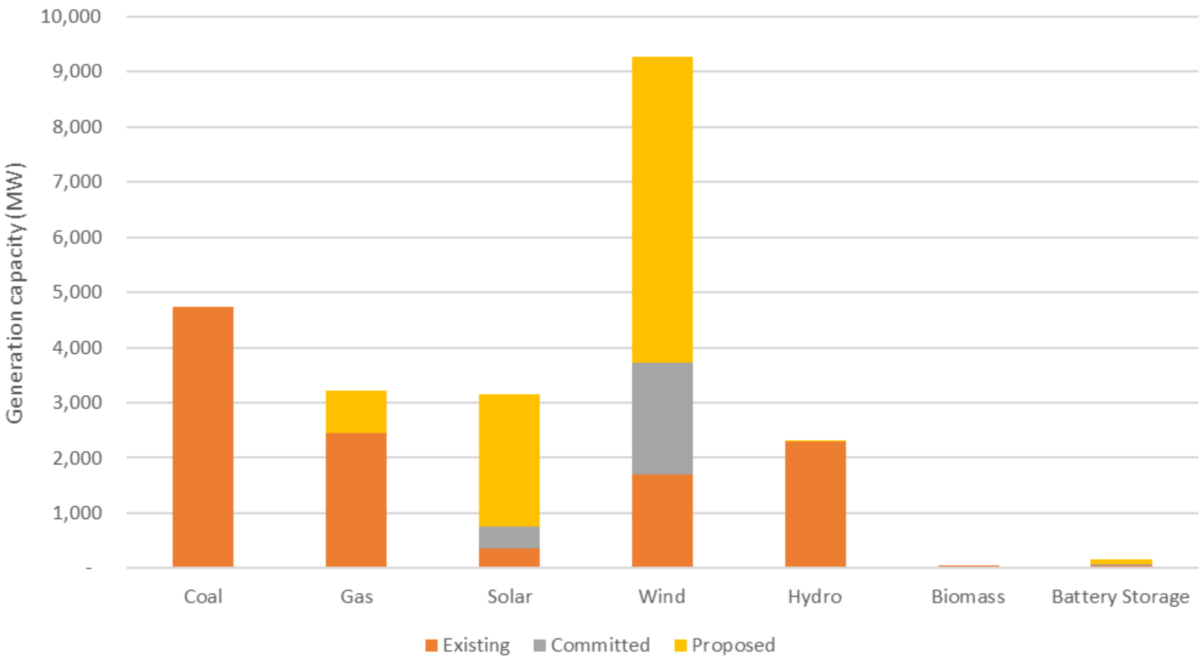


Figure 13 Existing, committed and proposed large-scale generation capacity in Victoria (MW), as at 10 May 2019

	Coal	Gas	Solar	Wind	Hydro	Biomass	Battery storage
Existing	4,740	2,460	354	1,693	2,286	58	55
Committed	-	-	396	2,025	-	-	20
Proposed	-	765	2,401	5,550	34	-	92

[74] The remaining approximately. 1% of generation capacity in Victoria is a combination of biomass and energy storage sources.

[75] AEMO, Generation Information webpage, Victoria update 10 May 2019, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[76] See maps of these projects on VAPR Network Development layer at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards

While renewable generation is being rapidly added to the system, several coal-fired generators, which have been Victoria's principal source of energy security since the power system's inception, are approaching end of technical life. The retirement of Hazelwood Power Station in Victoria in 2017 withdrew 1.6 GW of conventional coal generation from the power system. The 2018 ISP[77] noted that a further 15 GW of conventional generation across the NEM will reach its end of technical life by 2040. This includes Yallourn Power Station, a 1.4 GW coal-fired generator connected in the Latrobe Valley, which represents over 12% of Victoria's existing generation capacity and (based on latest available information[78]) is expected to begin a staged withdrawal of capacity between 2029 and 2032.

The 2018 ISP analysis indicated that retiring coal plant could be most economically replaced with a portfolio of utility-scale renewable generation, storage, DER, flexible thermal capacity, and transmission infrastructure. AEMO is working closely with proponents to facilitate this transition in an orderly manner.

6.1.2 Victorian Renewable Energy Target (VRET)

The Victorian Government has legislated a VRET target of 40% by 2025 and plans to deliver a VRET of 50% by 2030. To support the achievement of this target, and to provide certainty to renewable generation investors, the Victorian Government held a Reverse Auction in 2017. This process included calls for large-scale technology-neutral renewable energy projects, and large-scale solar-specific renewable energy projects.

Six projects were selected, comprising 674 MW of wind generation and 255 MW of solar generation. These projects have now been awarded 15-year support agreements with the Victorian Government[79].

6.1.3 Existing and committed renewable generation

There is currently 4.4 GW of renewable generation connected to the Victorian network, with a further 2.4 GW committed to connect by the end of 2020[80]. While hydroelectric generation in the north-east of the Victorian DSN makes up more than half of the existing renewable generation mix in Victoria, wind is expected to become the largest renewable fuel source, with 2.3 GW of wind generators committed to connect by the end of 2020.

AEMO has published a Victorian generation connections map[81] illustrating existing operational generator connections, and projects that are committed and moving through the Completion and Commissioning phase of the connection process. Many new wind farms are connecting close to the 500 kV backbone of the power system in south-west Victoria. However, wind farm developments are increasingly moving north towards the western Victoria region, where high-quality wind resources are abundant, but network infrastructure is limited.

There are also a number of solar generator connections in north-west Victoria, where solar resources are high quality, but where network infrastructure is the weakest in the state.

Increased investment in wind and solar projects in weak parts of the network is presenting technical and financial challenges for developers, as discussed in Section 6.2. To manage the risk of constraint due to network limitations, some developers are considering integrating energy storage solutions into their project design. AEMO anticipates this trend will continue as thermal and stability constraints become increasingly onerous, system strength diminishes, and larger network losses impact generator MLFs.

Despite the technical complexities of integrating renewables to the grid, the growing level of new and committed generators demonstrates the industry's ability to overcome these challenges by collaborating to deliver innovative solutions to emerging power system issues in Victoria.

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[77] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[78] At: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Generation_Information/Projects-Expected-Closure-Date.xlsx.

[79] See the VRET webpage at https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets, and the VRET auction webpage at https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-auction-scheme.

[80] 'Committed' status criteria is described on AEMO's Generation Information Page, under the Background Information tab on each regional spreadsheet.

[81] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps.

The strong growth in renewable generation is also occurring in neighbouring states, with approximately 1 GW of solar development committed to connect in south-west New South Wales in 2019-20. Given their proximity, these developments will have a material impact on the Victorian network, and on other renewable projects connected in the north-west of Victoria. AEMO is managing these inter-dependencies through close joint planning with the New South Wales TNSP, TransGrid.

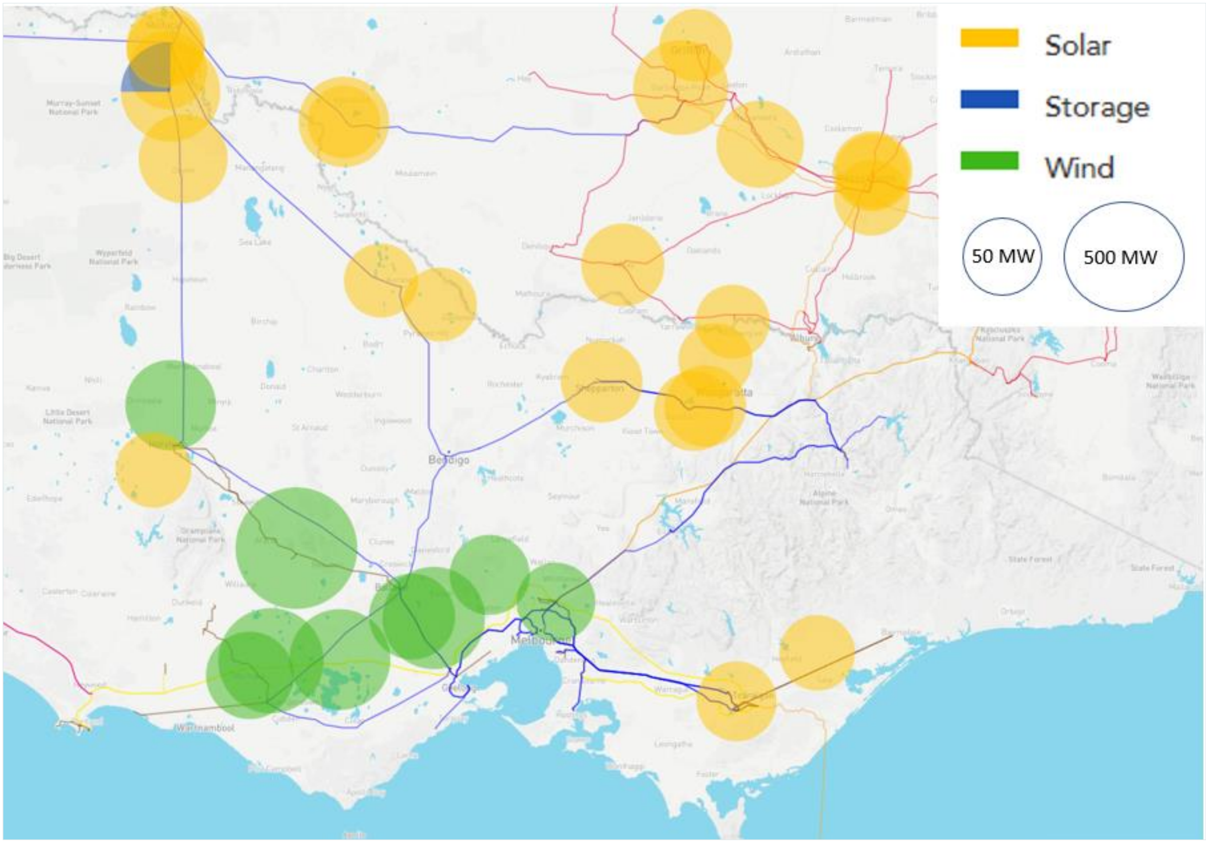
6.1.4 Current investor interest

Renewable energy investment continues to surge in Victoria, with a further 8 GW of wind, solar, and hydro generation and battery storage projects proposed to connect[82] in Victoria in the coming years.

Figure 14 presents a spatial representation of aggregated connection applications in Victoria in Q2 2019[83]. As noted above, investors are continuing to favour the western Victoria area, and interest in solar projects is rapidly increasing, while energy storage solutions are increasingly being considered as a means of diversifying developer revenue streams and minimising exposure to network constraints.

An additional 12 GW of renewable generator projects are in the early enquiry phase of the transmission connections process. AEMO's Victorian generation map[84] includes a summary of these early enquiry projects. While not all of these projects will progress to the next stage, AEMO is working closely with each proponent to provide as much information as possible to allow them to make informed investment decisions. AEMO is also assisting investors to explore opportunities to develop renewable generator clusters, allowing investors to collaborate and share investment costs[85].

Figure 14 Spatial representation of aggregated connection applications



[82] 'Proposed' status criteria is described on AEMO's Generation Information Page, under the Background Information tab on each regional spreadsheet.

[83] AEMO's interactive map will be updated in the near future to include updated aggregated connection applications data, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards.

[84] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps

[85] Connecting Generator Clusters to the Victorian Electricity Transmission Network: https://www.aemo.com.au/-/media/Files/PDF/0170-0015-pdf.pdf

6.2 Locational signals

The NEM operates under an open access regime. A participant has the ability to apply to connect a generator to any part of the transmission network, subject to meeting connection standards set out by the Network Service Provider (NSP) and by AEMO[86].

However, there is no guarantee that the transmission network has, or will have, the capacity to enable the energy output of a particular generator. Connected generators compete with each other for dispatch economically, and are also subject to network constraints.

The open access regime allows a future connection to materially change network congestion and electrical losses by changing power flows on the transmission system. Therefore, all existing and developing generator projects face a risk of network congestion if the capacity of the transmission network is exceeded by future generator connections.

Locational signals, such as network constraints, MLFs, and system strength levels, are used in the NEM to inform and incentivise proponents to invest in areas of the network that are likely to provide most value to electricity consumers. These signals are discussed in the following sections.

6.2.1 Network constraints

The transmission network has a finite amount of capacity to transfer power from generators to consumers. AEMO manages dispatch and operates the network within a technical envelope using constraint equations in the NEM dispatch engine (NEMDE)[87]. These constraint equations ensure that dispatch instructions for scheduled and semi-scheduled entities do not exceed the secure operating range of the system.

The order in which generators are dispatched is driven by variable operational conditions, economic considerations (including bid quantities and prices), and the location of each generator relative to constrained network elements and other generators.

Since constraint equations limit the power output of generation, constraints have a direct impact on pricing and dispatch. Generators connecting to heavily constrained parts of the network may risk reduced revenues.

Thermal constraints are used to control the dispatch of generation and re-route power flows to prevent overloading of a transmission element, such as a transmission line or transformer, under system normal and credible contingency conditions.

Stability constraints arise when power system conditions approach the boundaries of voltage, transient, or oscillatory stability limits. The increasing connection of inverter-based generation is impacting the stability and dynamics of generator control systems, and the ability of the power system to remain in stable operation.

The Victorian network was historically designed to support the transfer of power from large coal generators (principally in the Latrobe Valley) to load centres in the greater Melbourne region, and to allow for interconnection with New South Wales, South Australia, and Tasmania. The network in the western parts of the state was designed to feed local demand, and has not previously needed the infrastructure to support large supply volumes. Many parts of the western Victoria transmission network are now beginning to experience thermal and stability constraints as significant levels of new generation connect in this area.

Chapter 4 provides details of the emerging and interim network limitations which may result in generator constraints in the interim period between now and delivery of the current Victorian RIT-T projects. AEMO also continues to monitor the emergence of new limits – in particular, those limits that may only become significant following an unexpected change in local demand, generator investment, or generator withdrawal.

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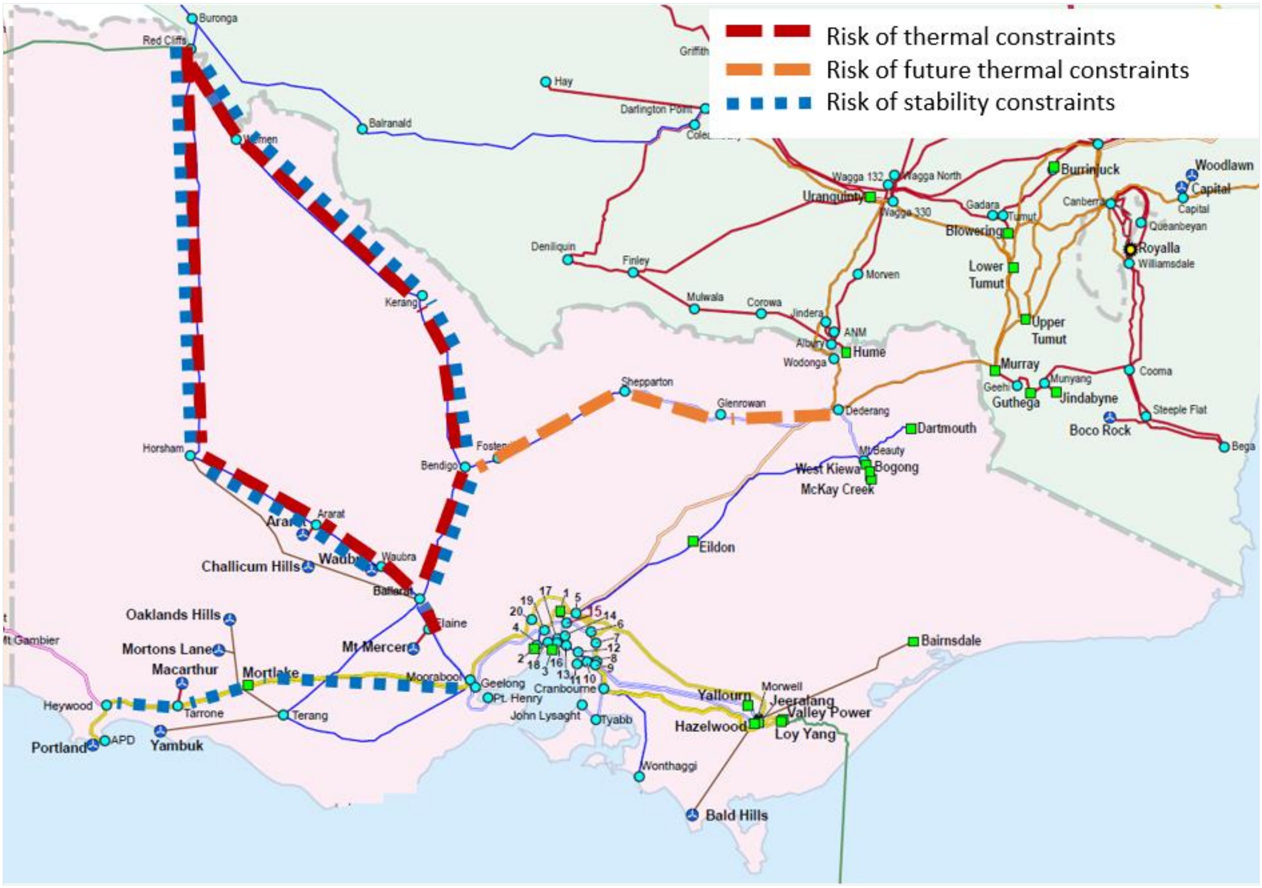
86 For an overview of the connection process, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview.

87 See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Dispatch-information.

Figure 15 illustrates the areas of the Victorian network that are at risk of constraint, now or in future, based on projected generator connections over the study horizon.

Figure 15 Potential constraints risks for new generators in Victoria



Western Victoria

Currently over 1 GW of wind generation is connected or commissioning between Ballarat and Murra Warra in western Victoria. When these generators are operational, the Ballarat – Waubra – Horsham lines will be loaded beyond their thermal capacity, which will result in thermal constraints. These limitations are discussed in Section 4.5.

In addition to these connections, a further 400 MW of solar plant is connected or commissioning between Red Cliffs and Kerang. These connections compound the above constraints, and lead to additional thermal constraints on the Red Cliffs – Wemen – Kerang – Bendigo – Ballarat lines under high generation conditions.

Due to the high levels of inverter-based generator connections in western Victoria, AEMO has identified a new monitored constraint which occurs for an outage of any line between Red Cliffs and Ballarat (via Horsham) or Red Cliffs and Bendigo. During these conditions, undamped voltage oscillations may occur following a contingency, with the potential to cause system interruptions or collapse in this region[88]. Constraint equations must be implemented to restrict generation output to maintain system security under these conditions. This limitation is discussed further in Section 4.7.

[88] Discussed further in an industry communique published by AEMO in February 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Planned-outages-in-the-North-Western-VIC-and-South-West-NSW-transmission-network-industry-communique.pdf.

Increased generation through this part of the network may also increase network losses and result in reduced MLFs in the area. New generators connecting here may also face increasing system strength remediation costs. Sections 6.2.2 and 6.2.3 discuss MLF and system strength issues in more detail.

Generator proponents considering future project development in western Victoria are encouraged to read AEMO's *Generator Connections to the Western Victoria Transmission Network Q&A*[89], which provides more information concerning issues in the area and AEMO's approach to managing these issues.

AEMO is progressing a Western Victoria Renewable Integration RIT-T to unlock generation capacity in the region and deliver cost efficiencies for Victorian electricity consumers. This project is expected to be delivered in 2025, and Section 3.1 provides more information on the project status. The potential benefits of this project for generation developers are discussed in Section 6.3.

Central-north Victoria

AEMO has observed significant interest from solar developers investigating connection opportunities in the central-north area of Victoria. Currently, 100 MW of solar generation is undergoing commissioning, while more than 300 MW of solar generator projects are progressing through the application phase of the connections process. A further 2.7 GW of connection enquiries are being processed between Bendigo and Dederang[90].

Due to the limited number of flow paths, and the thermal capacity of these lines, AEMO anticipates the emergence of new thermal congestion in the area if this volume of projects progress to connection.

The 2018 NTNDP[91] identified moderate levels of system strength in the area, which is expected to reduce when solar generation begins to connect nearby. Therefore, there will be a need for system strength remediation in future as new generators connect in the region.

South-west Victoria

There is almost 900 MW of wind generation capacity currently in service in the south-west of Victoria, between Moorabool and Heywood. This area does not currently experience significant thermal limitations because of nearby high-capacity 500 kV infrastructure that provides interconnection with South Australia.

A further 1.9 GW of wind projects in the area are progressing through the application phase of the connection process. AEMO expects that constraints may become more binding if these generators proceed.

In addition, there remains a limit to the amount of power that can be produced from generators west of Moorabool during an outage of a 500 kV line in the area. This constraint prevents high rate of change of frequency (ROCOF) following the loss of a 500 kV circuit between Moorabool and Heywood, which separates western Victoria and South Australia from the rest of the NEM. As generation increases in the area, this limitation may result in increased levels of generator constraints in future.

Eastern Victoria

The transmission network between Melbourne and the Latrobe Valley was designed to transfer large volumes of power from large coal-fired plant in the Latrobe Valley to load centres around Melbourne. As these large generators reach end of life and withdraw from the power system, there may be an opportunity for generator developers to leverage existing high capacity transmission infrastructure by connecting new generation into the area.

Wind resources in the area are high in quality, and there has been some interest from industry in investigating offshore wind opportunities nearby. In addition, TasNetworks is currently progressing a RIT-T on the economic viability of a second Bass Strait interconnector. If successful, this project may connect next to existing 500 kV assets in the Latrobe Valley area.

[89] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/New-generator-Connections---NW-VIC-Q-and-A.pdf.

[90] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps.

[91] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

Mitigating the risks of network constraints

It is crucial that new and intending generator proponents understand the potential impacts of network constraints and network congestion on the viability of their projects. Investors and developers with transmission connection proposals should engage with AEMO as early as possible in the project development process to seek advice about the network in the region, and discuss potential opportunities and risks associated with their project proposal. Subject to certain conditions[92], AEMO may also make current network data available for intending participants to conduct their own studies on the implications of these constraints on their proposed projects.

AEMO publishes an Annual NEM Constraint Report[93], which provides market participants with information about changes in congestion patterns across the previous five years, details constraint equation performance, and discusses issues related to transmission congestion for the year.

Investors and developers are encouraged to perform detailed technical analysis to assess the potential impact of network constraints under a range of possible future scenarios. Such comprehensive feasibility studies should be performed before advancing through the connection process and include careful consideration of the potential impact of network constraints, network development projects, and potential competition from other generator proponents nearby.

Network congestion can typically be alleviated by network augmentation investments. TNSP-driven network augmentation is subject to a RIT-T, which requires that any such investment maximises the net present value of market (consumer) benefits. As discussed in Chapter 3, AEMO is progressing several network development projects which, once approved, will begin to provide relief to identified emerging network constraints.

AEMO notes that some investors are also considering the following activities to potentially manage constraint risks:

- Implementing energy storage solutions to relieve congestion by storing energy during times of constraint and releasing it during times of lower congestion. Storage solutions, such as fast acting batteries, may also be utilised to increase system stability.
- Incorporating fuel diversity to limit congestion risks by reducing reliance on a single fuel, which may compete with nearby generators at the same time each day.
- Co-ordinating with other developers to upgrade the transmission network, or share investment costs to connect at strong, high-voltage connection points.
- Implementing dynamic reactive devices to improve voltage stability in weak areas of the network.

6.2.2 Marginal loss factors

Electrical energy is lost as power moves from a generation source to a load centre, due to resistive heating of transmission equipment (including lines and transformers). These losses are represented as MLFs at every existing load or generation connection point in each NEM region. This section will focus on MLFs from a generator connection perspective.

MLFs are applied to market settlements, adjusting generator payments to reflect the impact of the generator's incremental energy transfer losses. A generator's revenue is directly scaled by its MLF, through both electricity market transactions and revenue derived from large-scale generation certificates (LGCs).

For a generator, the MLF reflects the marginal (next megawatt) difference between the generator's output and the actual energy that would be delivered to consumers at the regional reference node (RRN), which for Victoria is Thomastown Terminal Station in Melbourne.

MLFs are a key locational signal in the NEM, providing investors with an incentive to connect new generation electrically close to the RRN and leverage efficiencies in the transport of energy across the system.

[92] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Network-Data/Policy-on-provision-of-network-data.

[93] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Network-status-and-capability.

There are a number of key factors that affect a generator's MLF:

- If a generator is located in a remote area with very little demand to supply locally, the power generated must travel large distances to feed load centres. This incurs significant losses, and results in that generator having a low MLF.
- Electrical losses across a transmission line increase with increased loading. The more congested a transmission pathway is from the generator to load, the higher the losses accrued. Therefore, if the output of the generator is co-incident with other sources in the area, congestion will be high for the times of the day that the generator is producing energy.
- Other factors impacting MLFs include changes to local demand, interconnector flows, and retirement of coal-fired generation, as these impact the ways in which parts of the network are utilised.

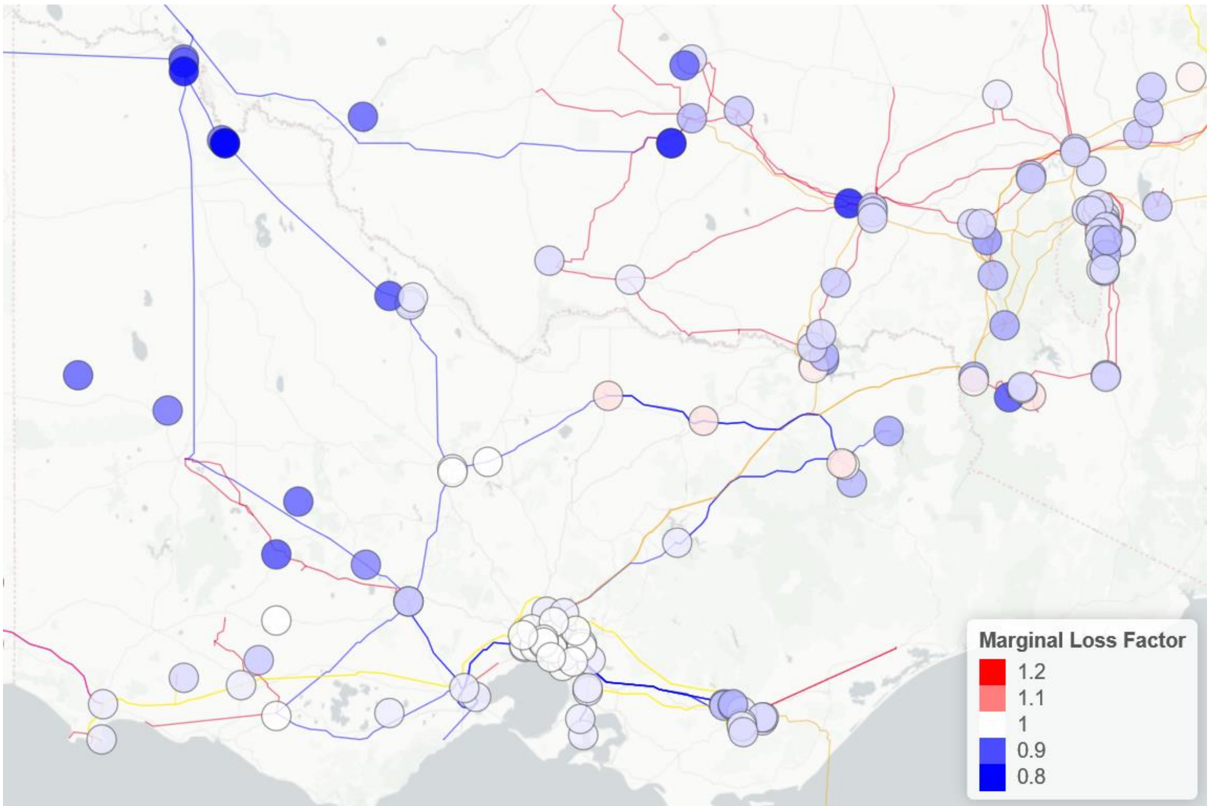
MLFs are calculated for each connection point and fixed annually. They are subject to change over time depending on changes to network flows due to network, demand, or generation changes. The MLF calculation methodology and other supporting documents are published by AEMO[94].

Investors should carefully consider the impact of MLFs when assessing the financial viability of a project, including exposure to future MLF changes over time.

Current MLF levels

AEMO has published a 'Regions and Marginal Loss Factors' report[95] detailing 2019-20 MLFs for each connection point in the NEM. Figure 16 illustrates Victoria's 2019-20 MLFs[96].

Figure 16 Map of 2019-20 MLFs for connection nodes in Victoria



[94] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

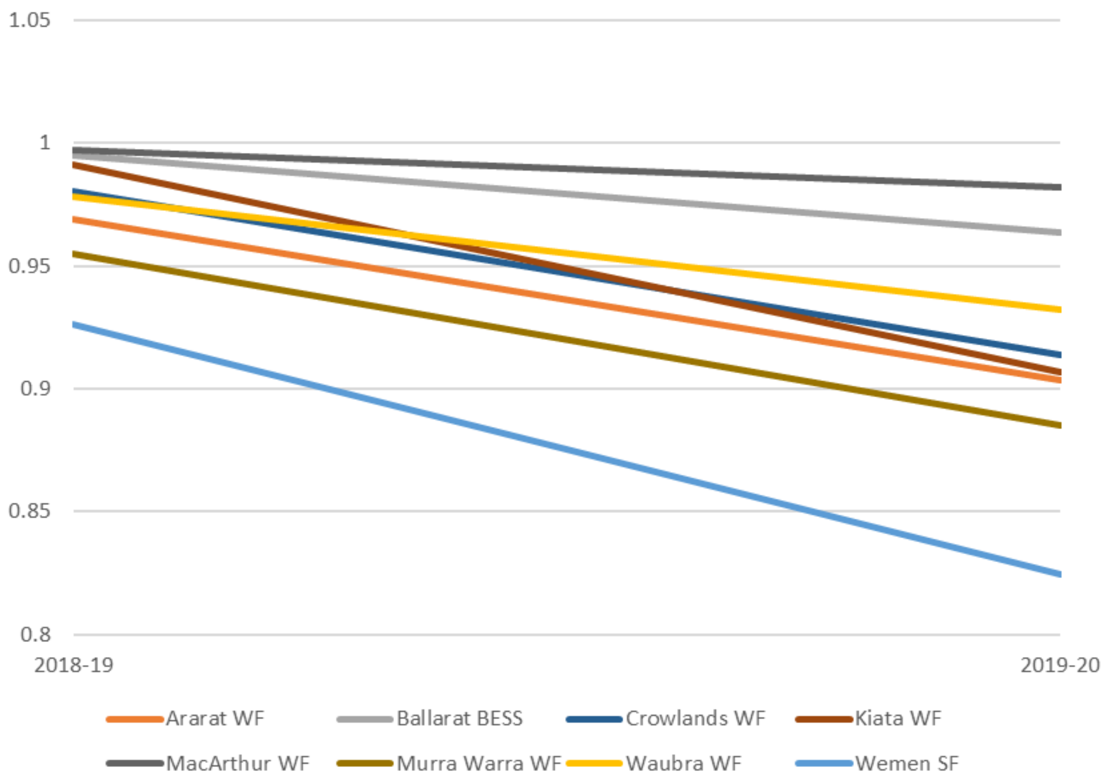
[95] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

[96] MLFs will be included in AEMO's interactive map in the near future, including a comparison of 2019-20 and 2018-19 MLFs, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards.

In the western Victoria region, the connection of new generation has resulted in large volumes of power being transferred considerable distances over congested transmission lines through the region. This has increased electrical losses and contributed to a decrease in MLFs for generators in the area. Therefore, the generator MLFs in this region are some of the lowest in the NEM, with some generators experiencing a decline of over 10% between 2018-19 to 2019-20, as shown in Figure 17. This can have a material impact on generator revenue in these areas.

The connection of additional renewable generation in these locations will likely cause MLFs to fall further. Planned network development in Victoria, such as the Western Victoria Renewable Integration RIT-T, may improve network losses where higher capacity/higher voltage transmission lines replace existing high impedance/congested lines. However, these network developments are not expected to be in service until 2025.

Figure 17 Connection point MLF degradation from 2018-19 to 2019-20, as published on 21 June 2019



As detailed above, MLFs are heavily dependent on a number of factors which influence network losses, including local demand, local generation, interconnector flows, and a generator's energy output profile. Therefore, investors must consider MLF risks on a case-by-case basis.

AEMO notes that some investors are considering the following options to potentially manage MLF risks:

- Locating or connecting the generator electrically close to the RRN. Connecting at a higher capacity node may improve MLF.
- Implementing energy storage solutions to improve MLFs by load shifting energy and acting as local demand at times when generation is high.
- Introducing fuel diversity to an area, which can reduce correlation with the output of other generators nearby. For example, if an area is mostly composed of solar generation, a wind generator may take advantage of less congested network conditions overnight – potentially reducing the *average* network losses faced by the unit.

Investors should ensure MLF modelling of proposed generators is tested against a range of potential future scenarios, including future generator connections, network augmentations, and other market conditions.

AEMO's next ISP will include further MLF analysis to provide investors with additional guidance on potential future MLF trends.

6.2.3 System strength

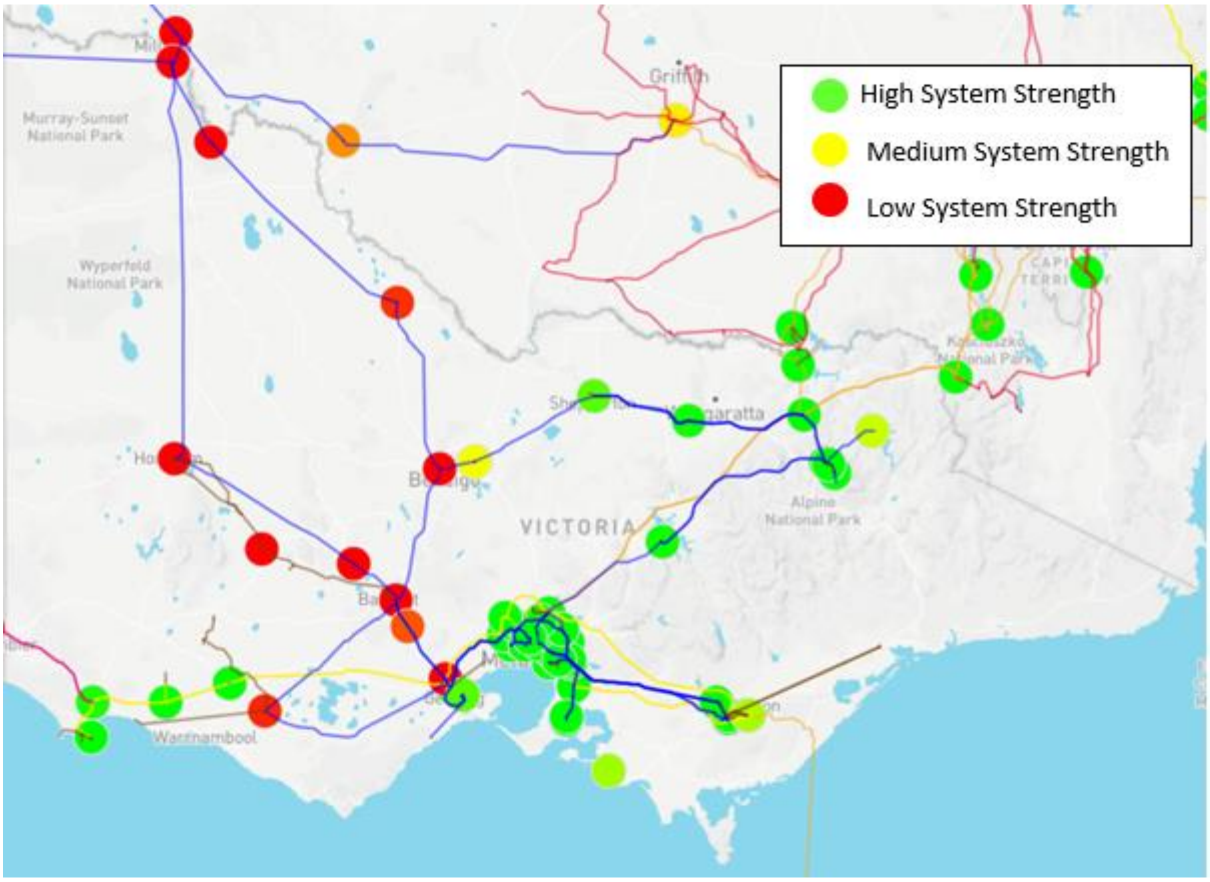
System strength is a measure of the ability of a power system to remain stable under normal conditions and to return to a stable state following a system disturbance. A key issue arising from the integration of non-synchronous generation to the power system, and the withdrawal of traditional synchronous generators, is a significant decrease in system strength in some parts of the power system.

A region is considered to have low system strength if it is remote from the high-voltage backbone of the network and there are low levels of local synchronous generation. When system strength reduces below a critical level, it can impact the behaviour of some types of generation, including typical solar and wind generators, causing these generating systems to become unstable and leading to wider network issues.

Most new generator applications in Victoria are proposing connection to areas of the network with low system strength, because these areas have some of the highest quality wind and solar resources. Since most solar and wind generators do not provide inherent contribution to system strength, the available system strength in these areas is deteriorating with new connections.

Following the publication of the 2018 ISP, AEMO has published an interactive map showing system strength levels for each connection node in 2018-19, and indicative system strength levels in 2028-29 and 2038-39.[97] Figure 18 provides a snapshot of the 2018-19 map.

Figure 18 Current system strength levels in Victoria in 2018-19



[97] Select '2018 Integrated System Plan – System Strength' layer at http://www.aemo.com.au/aemo/apps/visualisations/map.html

NER system strength requirements

In 2017, the Australian Energy Market Commission (AEMC) published a set of Rule changes which prescribed a framework for maintaining system strength on the power system[98]. There are two aspects to this framework:

- The minimum three-phase fault levels at each fault level node in each region are determined by AEMO[99].
- Fault level shortfalls are subsequently addressed by the SSSP. In Victoria, AEMO is the SSSP.

A system strength shortfall may be identified if the system strength in a region falls below the base system strength requirements due to demand changes, network changes, or generation plant retirements. SSSPs are not permitted to declare a system strength shortfall when the system strength reduction is caused by a new generator connection. No system strength shortfall has been identified in Victoria at this time.

New generator connections, market network service facilities, and alterations to existing generating systems that give rise to an adverse system strength impact must be addressed by the relevant Connection Applicant or Generator. This requires either a system strength remediation scheme, or by paying the connecting NSP to undertake system strength remediation works to alleviate the adverse system strength impact.

As new renewable generators are predominantly connecting to remote parts of the network, system strength requirements increasingly require developers to invest in additional remediation assets. Several projects are currently progressing through this system strength remediation process. AEMO's policy to facilitate generator connection clusters provides an opportunity for investors to share the costs of system strength remediation solutions.

System strength remediation

NER Clause 5.3.4B[100] places an obligation on new connecting generators, and generators undergoing modification, to 'do no harm' with respect to the system strength of the power system and the ability of other generators to maintain stable operation.

NSPs are required to undertake a system strength impact assessment for proposed new generator connections, in accordance with the *System Strength Impact Assessment Guidelines*[101]. This assessment includes:

a) a preliminary assessment if it is in receipt of a connection enquiry or a generator modification request;
b) a full assessment, if it is in receipt of an application to connect or a generator modification request, unless the preliminary assessment indicates that the full assessment is not needed, i.e. if the preliminary assessment concludes that the generator does not have a potential adverse impact on system strength.

The outcome of the NSP's assessment either confirms that there is adequate system strength following the new generator connection, or identifies an adverse impact on system strength. Adverse impacts on system strength may include:

- A reduction in system strength below the minimum level required to maintain system security, according to AEMO's assessment.
- A reduction in system strength such that the new generator connection interacts with existing plant and may result in the existing plant becoming unstable under certain conditions.

If the new connection causes an adverse system strength impact, the generator is obliged to remediate the impacts. The new generator is required to fund the costs associated with the provision of any required system strength services to address the impact of its connection on system strength. This rule is intended to

[98] At https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

[99] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[100] At https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current.

[101] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf.

incentivise new connecting generators to connect to parts of the network that have adequate system strength, and to maintain stable operation at low levels of system strength.

The *System Strength Impact Assessment Guidelines* provide a non-exhaustive list of potential system strength remediations solutions, including solutions which connect to the transmission network or behind the meter, and generating system control improvements. A number of innovative solutions are being investigated in the industry, including the use of non-synchronous plant based on grid-forming converter technologies. Investors are encouraged to seek out innovative ways to remediate system strength, including co-ordinating with other developers, AEMO and relevant DNSPs (if applicable) regarding system strength remediation investment solutions.

6.3 Opportunities and network developments

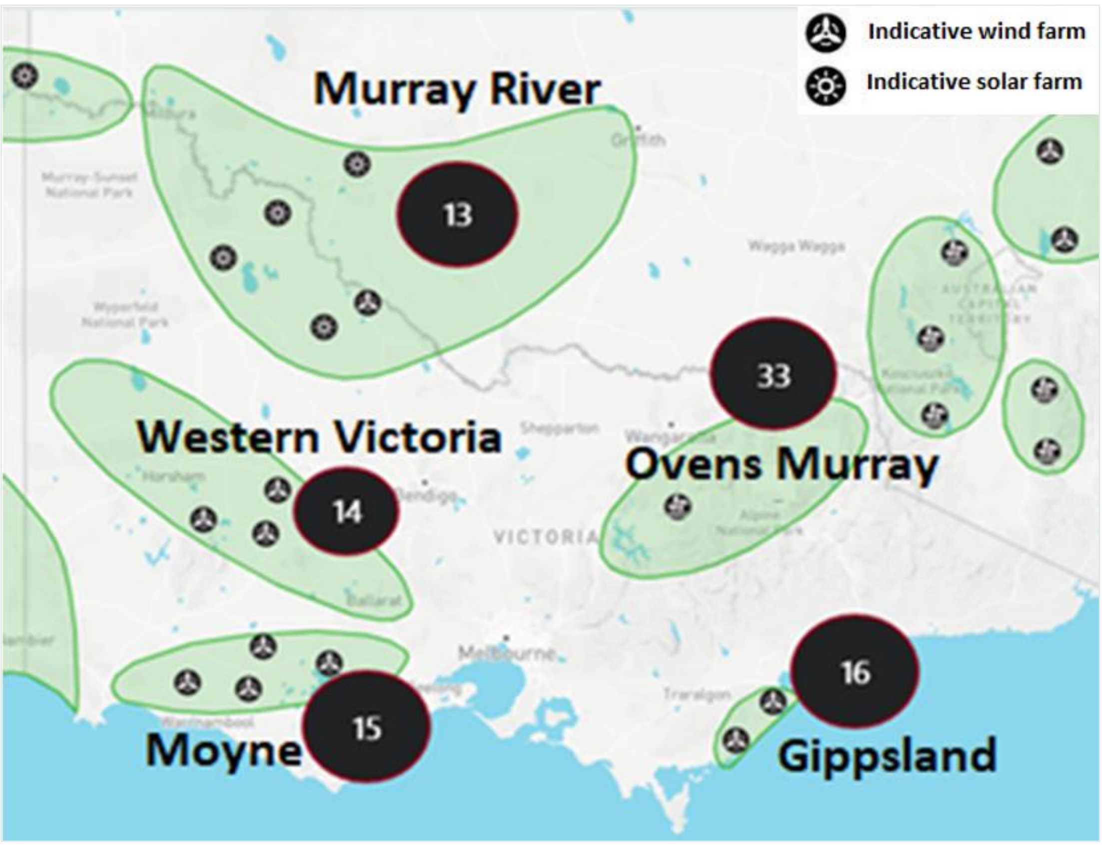
6.3.1 Renewable energy zones (REZs)

The 2018 ISP identified several potential REZs in Victoria where high-quality renewable resources are abundant, and overlaid this with locations where there is existing transmission network. These areas present a potential opportunity to reinforce the existing network and optimise investment to facilitate further renewable integration. Victorian REZs from the 2018 ISP are illustrated in Figure 19.

The 2018 ISP called for these areas to be prioritised for development to reduce the overall costs of renewable integration in the NEM. Strengthening the network in these locations, subject to a RIT-T, presents an opportunity to drive generator investment in the most optimal locations and reduce overall costs to consumers.

The REZs already being developed in western and north-western Victoria may warrant transmission investment to improve access to renewable projects in these areas. To connect renewable projects beyond the current transmission capacity, further action will be required. This is discussed in the following section.

Figure 19 Victorian renewable energy zones



6.3.2 Network developments

Augmentation of the transmission network can alleviate network congestion, lift stability limits, improve MLFs, and increase system strength. A regulated network augmentation investment must pass the RIT-T. Therefore, development of transmission infrastructure to support generator output can only occur to the extent that it will deliver net benefits to all those who produce, consume, and transport electricity in the NEM.

Beyond generation projects that have already reached committed status, RIT-T modelling must assume that future generator investments occur on an optimised, least-cost basis. This can result in augmentation projects lagging behind generation investment where investor decisions do not align with the most efficient consumer outcomes. Such generators must become 'committed' before their commercially-driven connection points are recognised by the RIT-T cost-benefit test as a sunk decision.

Consistent with the 2018 ISP, AEMO has commenced several RIT-T projects to reinforce the Victorian transmission network, alleviating network constraints and delivering cost benefits to consumers. These projects are discussed further in Chapter 3. This section summarises the potential benefits of these projects for generator connections in Victoria.

Western Victoria RIT-T

Increased renewable generation connections in the Western Victoria REZ have raised the need for reinforcement of the transmission network between Western Victoria and Melbourne.

The Western Victoria RIT-T project[102] will increase thermal capacity and voltage stability in western Victoria, providing improved access to network capacity for generators in the area. The project may also provide secondary benefits by improving system strength and reducing network losses.

Victoria to New South Wales Interconnector (VNI) RIT-T

Export capability from Victoria to New South Wales is frequently limited by thermal capacity and transient stability limitations. AEMO and TransGrid have established a joint VNI RIT-T[103] to reinforce the Victorian and New South Wales network, reducing thermal and stability constraints by increasing the transfer capability between Victoria and New South Wales.

Victorian Reactive Power Support RIT-T

AEMO is currently managing an NSCAS gap in Victoria related to voltage management at times of minimum demand. In particular, there is a need for additional absorbing reactive support on the system to keep voltages within operational limits during light loading on the system.

AEMO has established a Victorian Reactive Power Support RIT-T to deliver additional reactive power support at strategic locations in Victoria, minimising the risk of operator actions to reconfigure the network, and reducing the need for conventional plant to be online for reactive support purposes.

Redcliffs – Buronga component of SA Energy Transformation RIT-T (EnergyConnect)

ElectraNet has established a RIT-T to provide a new 330 kV interconnector between South Australia and New South Wales, aimed at reducing the cost of secure and reliable electricity to South Australia while facilitating the longer-term transition of the NEM to low-emission energy sources.

A component of the project scope will reinforce the 220 kV connection between Buronga in New South Wales and Red Cliffs in Victoria. This will provide greater access to network capacity for generator connections near Red Cliffs.

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[102] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/RITT.

[103] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

Additional Victoria to New South Wales interconnection

The 2018 ISP identified that further interconnection between Victoria and New South Wales may provide reliability benefits following further plant closures in the Latrobe Valley, as well as efficiency benefits through increased access to future hydro storage developments in the Snowy Mountains area.

While a RIT-T has not yet been triggered for this augmentation, AEMO has commenced preliminary technical studies.

6.4 Connections process and resources

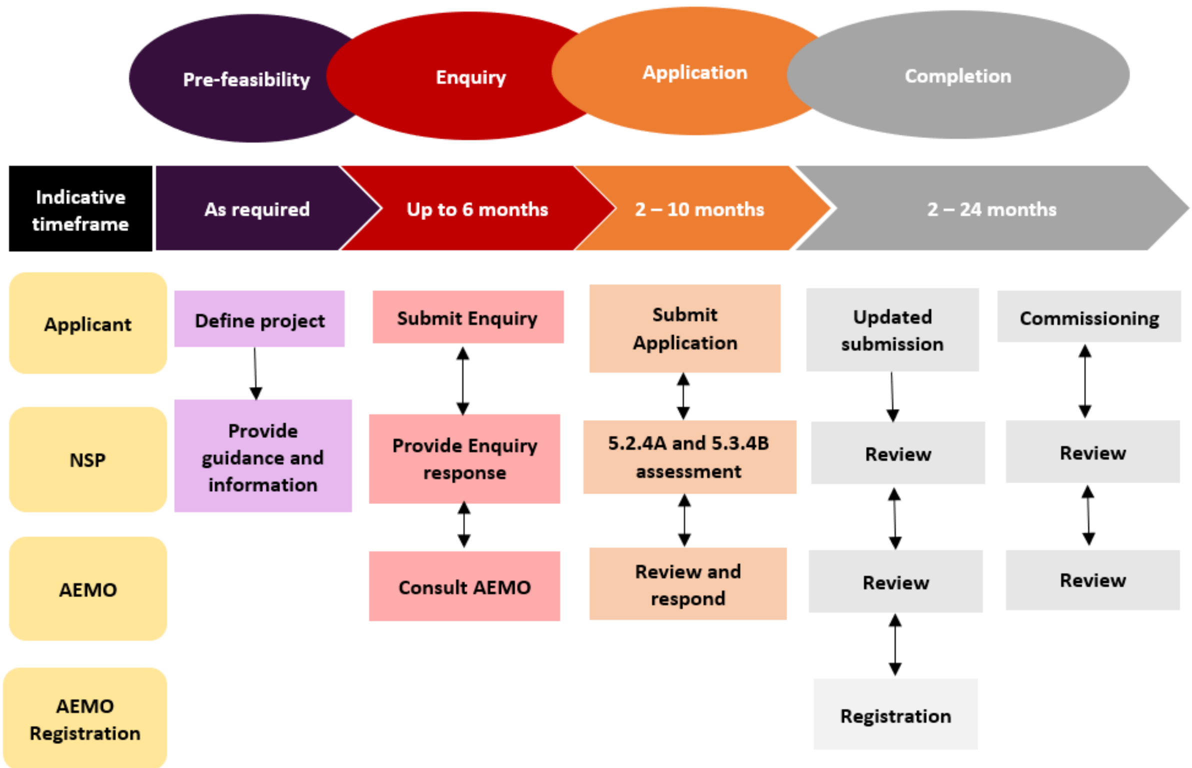
In Victoria, the DSN is operated by Declared Transmission System Operators (DTSOs) who are also registered as TNSPs. When processing applications to connect to the DSN, AEMO performs some of the responsibilities carried out in other states by the connecting TNSP. AEMO manages the connection process and is the main point of contact for the Connection Applicant. At each stage of the connections process, Connection Applicants should be aware of the roles and responsibilities of different stakeholders, as well as the regulatory arrangements governing the connection process.

This section provides information on the process for establishing a new connection or modifying an existing connection to the DSN in Victoria.

Connections process overview

Figure 20 provides a high-level view of the four key technical stages of the connections process, with indicative timeframes and the roles and responsibilities of the Connection Applicant/AEMO through the process[104]. This is consistent with other NSPs in the NEM[105].

Figure 20 Key technical stages of connections process



[104] Note that this excludes construction and contracting processes, which occur in parallel with the technical connections process.

[105] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/NSP-connction-process-diagram-v20.pdf.

Note that AEMO is currently reviewing the connections process to ensure connections are managed in an efficient and effective manner. The scope of this review includes interviews with a wide range of parties involved in the processes[106].

The key technical stages of the connections process are summarised below.

Pre-feasibility[107]

- This stage is optional, because the NER do not require Connection Applicants to follow this stage. Connection Applicants are encouraged to explore the feasibility of their project and begin discussions with AEMO, landowners, and relevant government authorities.
- Prospective applicants are encouraged to contact AEMO at the earliest opportunity. AEMO can provide applicants with comprehensive information about the connections process and high-level technical information that may assist in determining the location of the connection, and provide transmission network data for potential applicants[108].
- At this stage in the process, investors are encouraged to begin assessing the project feasibility and future risks to the project, considering thermal/stability constraints, MLFs, and system strength implications. Potential interactions with other competing generators in the area should be given close attention.

Enquiry[109]

This is the first formal stage of the connection process under Clause 5.3 (transmission network connections) of the NER. From this point forward, the process is prescribed by Chapter 5 of the NER.

To make an enquiry, applicants are requested to submit a Connection Enquiry Form[110] and any supporting information to AEMO, including the type, magnitude, preferred location, and timing of the proposed connection to the DSN.

AEMO's response typically includes:

- Requirements in respect of technical studies and access standards.
- Further information required to complete an application to connect.
- Advice on fees payable to process an application to connect (note there is no cost for submitting a connection enquiry to AEMO).

AEMO will also notify the incumbent DTSO of the enquiry.

Application[111]

Submitting a connection application initiates key activities in the connection process. Connection Applicants should submit their application to AEMO, together with all outstanding information requested by AEMO in its connection enquiry response.

The requirements of a complete application are covered in AEMO's Connection Application Checklist[112]. They include the following technical inputs:

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[106] For more information, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Network-connection-initiatives.

[107] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview/Stage-1---Pre-feasibility.

[108] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Network-Data/Policy-on-provision-of-network-data.

[109] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview/Stage-2---Enquiry.

[110] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/AEMO-Connection-Enquiry-Form.pdf.

[111] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview/Stage-3---Application.

[112] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Connection-Application-Checklist.pdf.

- Proposed performance standards[113]. Note that proposed performance standards must be consistent with the access standards detailed in the relevant Schedules of Chapter 5 of the NER.
- Description of the proposed installation, including data requirements outlined in the NER Schedules 5.4 and 5.5.
- Model package, including simulation models and associated design data[114].
- Project and commissioning programs.
- Location and proposed switching arrangement for connection to the DSN.

It is critical that the applicant reviews AEMO's Connection Application Checklist and Modelling Requirements page and ensures these requirements are satisfied before submitting an application. Proponents are encouraged to contact AEMO for support or guidance through this process if necessary.

AEMO will assess the application to connect together with the proposed performance standards. At the conclusion of this stage, AEMO will notify the Connection Applicant of AEMO's agreement to the performance standards and the outcome of the system strength impact assessment with any requirement for system strength remediation (clause 5.3.4A and 5.3.4B of the Rules). At this stage, AEMO will also assess the need for network augmentations and their contestability.

Completion[115]

Following completion of detailed design, the Connection Applicant should submit an application for registration to AEMO. The registration process is separate to the connection process and must be completed prior to commissioning, so Connection Applicants are encouraged to consider registration requirements as early as possible.

To assist with the registration process, Connection Applicants should ensure that:

- Complete simulation models of the connecting plant and associated design data are provided[116].
- Plant design meets agreed performance standards.
- The Supervisory Control And Data Acquisition (SCADA) system is ready.

Connection Applicants should also submit to AEMO:

- The commissioning program, including a test procedure and test schedule. This must be agreed at least three months before commissioning starts, so AEMO suggests this is considered as early as possible. AEMO has produced a guideline on commissioning requirements and templates for commissioning and R2 testing plans[117].
- Advice on material inter-network impact. This must be submitted at least 80 business days before expected synchronisation, if the facility will have such an impact.
- Commissioning results demonstrating compliance with the relevant agreed performance standards. These must be submitted within three months of completing commissioning.
- Finalised simulation models, R2 model validation report, and data sheets. These must also be submitted within three months of completing commissioning. Note that if there are material changes to the simulation model, AEMO may need to re-assess the performance standards.

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[113] For the template relating to each connection type, refer to the Documents Checklist at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview/Stage-3---Application.

[114] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Modelling-requirements.

[115] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview/Stage-6---Completion.

[116] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Modelling-requirements.

[117] See the Related Guides and Policies section at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview/Stage-6---Completion.

AEMC Rule changes

The AEMC made a Rule change[118], which commenced on 5 October 2018, that significantly changes the technical performance standards for generators seeking to connect in the NEM, and the process for negotiating those standards.

This new Rule requires that connecting generators be able to:

- Control their active power output.
- Limit their contribution to frequency and voltage disturbances.
- Supply and absorb reactive power for the control of voltage, where this service is needed on the power system.
- Inject and absorb reactive current during disturbances.
- Maintain operation in the face of certain frequency and voltage disturbances (including faults and contingency events).

This Rule also clarified the negotiating process for new connections. Under the Rule, negotiations can occur more efficiently so each generating system that connects is required to have a level of performance that maintains system security and quality of supply at the lowest cost.

Generator proponents are encouraged to review or seek advice on the new generator technical performance standards in advance of progressing a project to the Application Stage, as the new Rule requires higher levels of performance than previous standards and may have a material impact on the project.

[118] See https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards.

A1. DSN monitored limitation detail

These details for monitored transmission network limitations are grouped geographically.

A number of limitations identified as monitored in the 2018 VAPR are not included in the 2019 VAPR. This is because their triggers are now unlikely to occur in the 10-year planning horizon, or they have been addressed as part of an existing RIT-T (see Chapter 3). These limitations are due to changes in network loading resulting from committed network projects, or projected demand, and/or generation mix changes.

The changes in the list of monitored limitations are:

- New:
  - Sydenham – Keilor 500 kV line.
  - Voltage oscillation under planned outages in Western Victoria.
  - Melbourne Metropolitan Area voltage stability.
  - Red Cliffs – Horsham – Bulgana 220 kV line.
  - Red Cliffs – Wemen – Kerang – Bendigo 220 kV line.
  - Ballarat – Terang – Moorabool 220 kV line.
  - Ringwood – Thomastown and Templestowe – Thomastown 220 kV line loading.
  - High ROCOF in south-west Victoria.
- Removed:
  - Dederang – Murray 330 kV line (addressed as part of RIT-T).
  - Dederang – South Morang 330 kV line (addressed as part of RIT-T).

The options presented in the sub-sections below should be treated as indicative only, and a RIT-T will be required to determine the full list of network and non-network options as well as the preferred option. The preferred option may include one or a combination of the options presented in the sub-sections below.

A1.1 Eastern Corridor – monitored limitations

Table 8 Limitations being monitored in the Eastern Corridor

Limitation	Possible network solution	Trigger*	2018 NTNDP status	Contestable project status
Rowville – Yallourn 220 kV line loading	Upgrade the 220 kV Hazelwood – Rowville or Yallourn – Rowville lines.	During period of extremely high temperature and high output from Yallourn Power Station.	Not identified as a material limitation in the scenarios modelled.	The line upgrade is unlikely to be a contestable project.

* Triggers are the operating conditions under which a limitation may result in supply interruptions or constrain generation periodically.

A1.2 South-West Corridor – monitored limitations

Table 9 Limitations being monitored in the South-West Corridor

Limitation	Possible network solution	Trigger*	2018 NTNDP status	Contestable project status
Moorabool – Heywood – Portland 500 kV line voltage unbalance**	• A switched capacitor with individual phase switching at Heywood or near Alcoa Portland with an estimated cost of $14.4M. • An SVC or a STATCOM at an estimated cost of $33.3M. • Additional transposition towers along the Moorabool – Heywood – Alcoa Portland 500 kV line at an estimated cost of $37.9M.	New generation connections along the Moorabool – Heywood –Alcoa Portland 500 kV line potentially introduce voltage unbalance along the line. The impact of voltage unbalance levels increases in proportion to power flow magnitude and direction, new generation connection points, and output generated.	Limitation not considered as part of 2018 NTNDP scope as it is related to voltage quality.	• Switched capacitor and static VAr options are likely to be contestable projects. • Line transposition is unlikely to be a contestable project.
Inadequate south-west Melbourne 500 kV thermal capacity	A new Moorabool – Mortlake/Tarrone – Heywood 500 kV line with an estimated cost of $559.7M.	If significant wind generation and/or gas-powered generation (GPG) (over 2,500 MW in addition to the existing generation from Mortlake) is connected to the transmission network in the South-West Corridor.	Not identified as a material limitation in the scenarios modelled.	The new line is likely to be a contestable project.
Moorabool 500/220 kV transformer loading	• Install generation inter-trip schemes. • Install third Moorabool 500/220 kV transformer costing approximately $25.0M.	Large-scale new generation connected to western Victoria area, and congestion within western Victoria relieved to allow the new generation to be sent out of western Victoria.	Not identified as a material limitation in the scenarios modelled.	The new transformer is likely to be a contestable project.
High ROCOF in south-west Victoria	Install a post-contingent generation tripping control scheme to control ROCOF during a period when one of the 500 kV lines west of Moorabool is out of service.	• Increased probability of prior outages of 500 kV transmission line west of Moorabool • Increased generation connected to the 500 kV lines west of Moorabool.	Not identified as it is a localised issue.	The control scheme implementation is unlikely to be a contestable project.

* Triggers are the operating conditions under which a limitation may result in supply interruptions or constrain generation periodically.
** AEMO intends seeking a Rule change proposing an increase the negative sequence voltage imbalance levels on the transmission network.

A1.3 Northern Corridor – monitored limitations

Table 10 Limitations being monitored in the Northern Corridor

Limitation	Possible network solution	Trigger*	2018 NTNDP status	Contestable project status
Dederang – Mount Beauty 220 kV line loading	• Install a wind monitoring scheme. • Up-rate the conductor temperature of both 220 kV circuits between Dederang and Mount Beauty to 82°C, at estimated cost of $12.6M.	Increased NSW import and export.	Constraint identified during high export to NSW.	These are unlikely to be contestable projects.
Eildon – Thomastown 220 kV line loading	• Install wind monitoring scheme • Up-rate Eildon – Thomastown 220 kV line, including terminations to 75 °C operation, at estimated cost of $45.2M.	Increased NSW import and export.	Constraint identified during high import from NSW.	This is unlikely to be a contestable project.
Dederang 330/220 kV transformer loading	Install a fourth 330/220 kV transformer at Dederang at an estimated cost of $14.6M.	At times of over 2,500 MW of imports from NSW and Murray generation (with the DBUSS transformer control scheme being active).	Not identified as a material limitation in the scenarios modelled.	The new transformer is likely to be a contestable project.
Voltage stability at North Victoria/ South New South Wales	• Procure network support services, including the provision of additional reactive support (generating). • Install additional capacitor banks and/or controlled series compensation at Dederang and Wodonga terminal stations.	Increased import from New South Wales to Victoria	Not identified as a material limitation in the scenarios modelled.	These are both likely to be contestable projects.
Murray – Dederang 330 kV line loading	• Implement an automatic load shedding scheme to allow for operating the lines to a higher thermal rating. The cost of this option depends on contractual arrangement with services providers • Install third 1,060 MVA 330 kV line between Murray and Dederang with estimated cost of $186M (excluding easement costs). • Install second 330 kV line from Dederang to Jindera at estimated cost of $154M (excluding easement costs).	Increased import from NSW to Victoria or Murray generation.	Not identified as a material limitation in the scenarios modelled.	These are both likely to be contestable projects.

* Triggers are the operating conditions under which a limitation may result in supply interruptions or constrain generation periodically.

A1.4 Greater Melbourne and Geelong – monitored limitations

Table 11 Limitations being monitored in Greater Melbourne and Geelong

Limitation	Possible network solution	Trigger*	2018 NTNDP status	Contestable project status
Ringwood – Thomastown and Templestowe – Thomastown 220 kV line loading	• Cut in Rowville – Ringwood – Thomastown 220 kV at Templestowe and Rowville – Templestowe – Thomastown 220 kV at Ringwood to form the Rowville – Ringwood – Templestowe – Thomastown No. 1 and No. 2 circuits at an estimated cost of $14.2M plus any fault level mitigation work • New (third) 500/220 kV transformer at Rowville, with an estimated cost of $53.1M, plus any fault level mitigation works.	Increased demand in Eastern Metropolitan Melbourne.	Not identified as it is a localised issue.	The line cut-in is unlikely to be a contestable project.
Rowville – Malvern 220 kV line loading**	Cut-in Rowville – Richmond 220 kV No. 1 and No. 4 circuits at Malvern Terminal Station to form the Rowville – Malvern – Richmond No. 3 and No. 4 circuits at estimated cost of $11.1M.	Increased demand or additional loads connected to Malvern Terminal Station.	Not identified as it is a localised issue.	The line cut-in is unlikely to be a contestable project.
Rowville – Springvale – Heatherton 220 kV line loading	• Connect a third Rowville – Springvale circuit (underground cable) with estimated cost of $55.9M. • Connect a Cranbourne – Heatherton 220 kV double circuit overhead line with estimated cost of $36.2M.	Increased demand or additional loads connected to Springvale and Heatherton Terminal Station.	NTNDP did not identify this limitation as it is a localised issue.	The third circuit is likely to be a contestable project.
Rowville A1 500/220 kV transformer loading	Install a second 500/220 kV 1,000 MVA transformer at Cranbourne with estimated cost of $25.0M.	Increased demand in Eastern Metropolitan Melbourne.	Not identified as a material limitation in the scenarios modelled.	The new transformer is likely to be a contestable project.
South Morang H1 330/220 kV transformer loading	Replace the existing transformer with a higher rated unit in conjunction with SP AusNet's asset replacement program.	Increased demand in Metropolitan Melbourne and/or increased import from NSW.	Not identified as a material limitation in the scenarios modelled.	This is unlikely to be a contestable project.
South Morang – Thomastown No. 1 and No. 2 220 kV line loading	• Increase the transfer capability by installing wind monitoring facilities on the South Morang to Thomastown line. • Install an automatic load shedding control scheme to enable the use of five-minute line rating. • Install a third 500/220 kV transformer at Rowville, with an estimated cost of $25.0M, plus any fault level mitigation works.	Increased demand around the Melbourne Metropolitan area and/or increased export to NSW.	NTNDP did not identify this limitation as it is a localised issue.	The new transformer is likely to be a contestable project.

Limitation	Possible network solution	Trigger*	2018 NTNDP status	Contestable project status
Cranbourne A1 500/220 kV transformer loading	Install a new 500/220 kV transformer at Cranbourne Terminal Station with an estimated cost of $25.0M (excluding easement cost).	Increased demand around the Eastern Melbourne Metropolitan area.	Not identified as a material limitation in the scenarios modelled.	The new transformer is likely to be a contestable project.
Moorabool – Geelong - Keilor 220 kV line loading	• Connect a new single circuit Moorabool – Geelong 220kV line with a rating of approximately 800 MVA at 35°C, with an estimated cost of $11.3M. • Replace the existing Geelong – Keilor 1 and 3 220 kV lines with a new double circuit line, each circuit rated at 700 MVA at 35°C, with an estimated cost of $76.5M.	Large-scale new generation connected to western Victoria area, and congestion within western Victoria relieved to allow the new generation to be sent out of western Victoria.	Constraint identified in the NTNDP during high renewable generation, if large amount of wind and solar generation is connected in north-west Victoria.	This is unlikely to be a contestable project.
Keilor – Deer Park – Geelong 220 kV line loading* **	• Installing a new single circuit Moorabool – Geelong 220 kV line with a rating of approximately 800 MVA at 35° C, with an estimated cost of $11.3M. • Replacing the existing Geelong – Keilor No. 1 and No. 3 220 kV lines with a new double circuit line rated at 700 MVA at 35°C, with an estimated cost of $76.5M. • Parallel the existing three Geelong – Deer Park – Keilor 220 kV circuits to form a Geelong – Deer Park and Deer Park – Keilor circuit, each rated 810 MVA at 35° C, at an estimated cost of $3.1M.	Increased demand at Deer Park.	NTNDP did not identify this limitation as it is a localised issue.	These are unlikely to be contestable projects.
Sydenham – Keilor 500 kV line	• Installing a new single circuit Sydenham – Keilor 500 kV line with a rating of approximately 2,900 MVA at 35°C, with an estimated cost of $36.8M. • Uprated line rating of the existing 500 kV SYTS–KTS.	Increased generation in west and south-west Victoria supplying Keilor Terminal Station.	NTNDP did not identify this limitation as it is a localised issue.	These are likely to be contestable projects.
Melbourne Metropolitan Area voltage stability	Additional capacitors. An SVC or a STATCOM at an estimated cost of $33.3M.	Increased demand in the Melbourne Metropolitan area.	Not identified as a material limitation in the scenarios modelled.	These are likely to be contestable projects.

* Triggers are the operating conditions under which a limitation may result in supply interruptions or constrain generation periodically.
** This monitored limitation assumes five-minute ratings are already applied – an automatic load shedding control scheme to enable the use of five-minute line ratings is currently available to manage this limitation.
*** This monitored limitation assumes five-minute ratings will be applied – an automatic load shedding control scheme to enable the use of five-minute line ratings will be available to manage this limitation.

A1.5 Regional Victoria – monitored limitations

Table 12 Limitations being monitored in Regional Victoria*

Limitation	Possible network solution	Trigger**	2018 NTNDP status	Contestable project status
Voltage oscillation in western and north-west Victoria	• Implementation of control schemes. • Preferred option as identified by the Western Victoria Renewable Integration RIT-T.	• Increased probability of prior outages of local 220 kV transmission lines • Reduction in available fault level in the region	Constraint identified in the NTNDP during high renewable generation, if large amount of wind and solar generation is connected in north-west Victoria.	These are likely to be contestable projects.
Red Cliffs – Horsham- Bulgana 220 kV line	Installing a new single circuit Red Cliffs – Horsham - Bulgana 220 kV line with a rating of approximately 400 MVA at 35°C, with an estimated cost of $400M.	Increased generation in Regional Victoria and retirement of existing generation.	NTNDP did not identify this limitation as it is a localised issue.	These are likely to be contestable projects.
Red Cliffs – Wemen – Kerang – Bendigo 220 kV line	• Install an automatic load shedding control scheme to enable the use of five minute line rating. • Replace the existing Bendigo – Kerang – Wemen – Red Cliffs 220 kV line with a new double circuit 220 kV circuit line at an estimated cost of $589.0 million.	Increased generation in Regional Victoria and retirement of existing generation.	NTNDP did not identify this limitation as it is a localised issue.	These are likely to be contestable projects.
Ballarat – Terang – Moorabool 220 kV line	• Install an automatic load shedding control scheme to enable the use of five minute line rating. • Replace the existing Ballarat – Terang – Moorabool 220 kV line with a new double circuit 220 kV circuit line.	Increased generation in Regional Victoria and retirement of existing generation.	NTNDP did not identify this limitation as it is a localised issue.	These are likely to be contestable projects.
Inadequate reactive power support in Regional Victoria	Staged installation of additional reactive power support in Regional Victoria.	Increased demand and/or decrease in power factor in Regional Victoria.	NTNDP did not identify this limitation as it is a localised issue.	Additional reactive support is unlikely to be a contestable project.
Dederang – Glenrowan – Shepparton – Bendigo 220 kV line loading	• Install an automatic load shedding control scheme to enable the use of five-minute line rating. • Install a phase angle regulating transformer on the Bendigo – Fosterville – Shepparton 220 kV line at an estimated cost of $47.5M. • Replace existing Dederang – Glenrowan, Glenrowan – Shepparton and Shepparton – Bendigo 220 kV lines with new double circuit lines at respective estimated costs of $70.3M, $63.0M, and $97.1M (total $237.5M).	• Increased demand in Regional Victoria and/or increased import from NSW. • Large-scale new generation connected to Western Victoria area, and congestion within Western Victoria relieved to allow the new generation to be sent out of Western Victoria.	NTNDP did not identify this limitation as it is a localised issue.	The new transformer or new transmission lines are likely to be contestable projects.

Limitation	Possible network solution	Trigger**	2018 NTNDP status	Contestable project status
Long term Victoria – New South Wales transfer limitation	New interconnection options between NSW and Victoria.	• Retirement of generation in Victoria or NSW. • Increased generation or energy storage capacity in key REZs and locations.	Constraint identified in the ISP.	These are both likely to be contestable projects.

* AEMO is conducting a RIT-T to identify the preferred augmentation option to address DSN capacity limitations in the regional Victoria. The outcome of this RIT-T will affect the status of the limitations in this area.

** Triggers are the operating conditions under which a limitation may result in supply interruptions or constrain generation periodically.

A2. Distribution network service provider planning

This appendix lists the preferred connection modifications from the 2018 Transmission Connection Planning Report[119] and the potential DSN impacts and considerations.

Table 13 Distribution network service provider planning impacts

Location/terminal station	Preferred connection modification	DSN impacts and considerations
Altona No. 3 and 4 66 kV	Install additional transformation capacity and reconfigure 66 kV exits at ATS by the end of 2025.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.
Cranbourne 66 kV	Install a fourth Cranbourne 150 MVA 220/66 kV transformer by end of 2027.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.

[119] Jemena, CitiPower, Powercor, AusNet Services and United Energy. *2018 Transmission Connection Planning Report*, at https://www.unitedenergy.com.au/wp-content/uploads/2018/12/Transmission-Connection-Planning-Report_FINAL_2018.pdf https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/Regulatory-Publications/Transmission-Connection-Planning-Report-2018.ashx?la=en.

A3. Transmission network limitation review approach

In assessing the impact of limitations, AEMO considers information from power system performance analysis and market simulations each year for the next 10 years regarding:

- The percentage N and N–1 loadings of transmission plant associated with the network loading limitation, based on the continuous and short-term ratings respectively.
- The load and energy at risk. Load at risk is the load shedding required to avoid the network limitation. Energy at risk is the resulting unserved energy (USE).
- Expected USE, which is a portion of the energy at risk after taking into account the probability of forced outage.
- Dispatch cost, which is the additional cost from constraining generation.
- Limitation cost, which is the total additional cost due to both constraining generators and the expected USE.

Power system performance analysis generally uses more conservative assumptions about demand, temperature, and wind speed to capture as many network limitations as possible for later market simulation testing. For this reason, DSN performance analysis results (that is, the percentage loadings) can show more severe impacts than market simulations.

AEMO derives forecast transmission plant loadings using load flow simulations, and develops load flow base cases for these simulations using the following inputs:

- The 10% POE terminal station demand for maximum demand base cases.
- Historical maximum power transfers for a high Victoria to New South Wales power transfer base case.
- Typical generation dispatch and interconnector power transfer patterns under the given operating conditions.
- The system normal operational configuration for the existing Victorian transmission network.
- Committed transmission network augmentation and generation projects, and other projects (or their equivalent), which AEMO considers necessary for maintaining the power system in a satisfactory, secure, and reliable state during summer maximum demand periods.
- Standard continuous ratings and short-term ratings at 45 ºC and 0.6 m/s wind speed, unless otherwise indicated.
- Unless indicated, 15-minute ratings as short-term ratings for transmission lines. Some transmission lines in Victoria are equipped with automatic load shedding schemes, which, once enabled, will avoid overloading by disconnecting preselected load blocks following a contingency. These schemes allow the lines to operate up to their five-minute short-term ratings.

- Wind generation availability during maximum demand assumed to be 6.5% of the installed capacity. For more information, see the Wind Contribution to Peak Demand study results.

AEMO bases the market impact of each network limitation on probabilistic market simulations that apply:

- Weighted 50% POE and 10% POE maximum demand forecasts (weighted 70% and 30% respectively).
- Historical wind generation availability.
- Historical load profiles.
- Dynamic ratings based on historical temperature traces.
- Non-committed new and retired generation, consistent with latest NTNDP generation expansion plan.

For more information about the transmission network limitation review approach, see the Victorian Electricity Planning Approach[120].

[120] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role.