Victorian Annual Planning Report

November 2020

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 generally based on information available to AEMO as at July 2020, although AEMO has incorporated more recent information where practical.

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VERSION CONTROL

Version	Release date	Changes
1	12/11/2020	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) reviews the performance of the DSN and assesses its adequacy to meet reliability and security needs over the coming 10 years.

The VAPR builds on the national plan developed through AEMO's *Integrated System Plan* (ISP), and provides local insights relating to network capability, system performance, and emerging network needs. This work is designed to allow stakeholders to make informed decisions, while also identifying network upgrade projects that are likely to deliver net economic benefits and lower-cost outcomes for consumers, as assessed under the current regulatory framework.

Victoria's energy system continues to transform at a rapid rate

The energy landscape in Victoria continues to change, driven by strong investment in large-scale renewable generation projects. New investment in the west of the state is creating additional supply centres, while an increasing penetration of non-synchronous generation continues to impact the stability and complexity of system operations.

Consumer-led investment in distributed energy resources (DER), such as distributed photovoltaic (PV) systems, has altered the shape of the daily demand curve, and is creating new challenges through larger credible contingency sizes, new record levels of minimum demand, and decreasing levels of voltage control, inertia, and system strength.

- While the DSN remained secure over the past year under typical operating conditions, a tightening supply balance, widespread bushfires, extreme weather events, and record low demands contributed to extremely difficult operating conditions and two days requiring dispatch of emergency reserves.
- Minimum demand continued to fall in 2019-20, reaching a record low daytime value of 3.3 gigawatts (GW) on 1 January 2020; further minimum demand records have since been set in the first half of 2020-21. This represents the second year in a row that Victoria's annual minimum occurred during the day, rather than overnight. These lower demands contributed to voltage control challenges, and new reactive power contracts have been used while long-term network investments are delivered.
- Victoria now has approximately 7.8 GW of existing or committed wind and solar generation, with large-scale projects contributing 4.9 GW and distributed PV contributing a further 2.9 GW. Victoria also has 2.3 GW of existing hydro units, and 75 megawatts (MW) of existing or committed battery storage.
- Since the 2019 VAPR, 1.6 GW of new large-scale wind and solar projects have connected or commenced commissioning, with a further 1.5 GW committed to connect, and 16.3 GW having lodged enquiries.
- AEMO's 2020 ISP identifies that a minimum of 13.2 GW of Victorian renewable generation would be required by 2030 to meet the Victorian Renewable Energy Target (VRET). This means Victoria will need at least an additional 5.4 GW of additional large-scale projects and DER investment to meet the VRET.
- Maximum demand peaked at 9.7 GW in January 2020, compared with only 9.3 GW in January 2019. AEMO's latest forecasts predict only marginal growth in peak demand over the planning horizon. Over the coming decade, system needs are likely to be dominated by minimum demand concerns and the integration of new generator projects including large pumped hydro schemes outside of Victoria.

AEMO's Transmission Roadmap for Victoria

To meet these changing needs AEMO is progressing a targeted suite of network development projects across the region and across the decade, as outlined in the VAPR as a *Transmission Roadmap for Victoria*.

The 2020 roadmap consists of almost $3.5 billion in transmission investment over the coming decade, and has been designed to address transitionary issues, maintain supply reliability, deliver system security, and meet government policy objectives. These investments act to reduce overall costs to consumers by enhancing competition, unlocking lower-cost generation supplies, and improving the efficiency of resource sharing between neighbouring regions.

The roadmap includes both committed and future projects that together address key thermal, stability, voltage control, system strength, and renewable energy zone (REZ) expansion needs in Victoria.

Milestone projects on the roadmap will deliver:

- **Improved voltage control** – AEMO and AusNet Services are installing four 100 megavolt amperes reactive (MVAr) reactors from 2021 to address voltage control limitations under light load conditions.
- **Greater interconnection with New South Wales** – AEMO and TransGrid are upgrading the Victoria – New South Wales Interconnector (VNI) to enable additional Victorian exports from late 2022.
- **System strength in north west Victoria** – AEMO has entered into non-market ancillary services (NMAS) agreements with two system strength service providers in the Red Cliffs area and is now progressing procurement of a permanent solution that will support existing renewable projects in the area.
- **REZ expansion in western Victoria** – AEMO has contracted AusNet to deliver staged network upgrades in western Victoria by 2025 to reduce network congestion and unlock additional renewable capacity.
- **Heightened system awareness** – AEMO is progressing the installation of Phasor Measurement Units (PMUs) during 2021 to improve visibility of network performance and the accuracy of system models.
- **Hosting capacity upgrade in south-west Victoria** – AEMO is investigating new limitations and solutions in the south-west corridor, associated with the volume of new generator connections in the area.
- **Major new interconnection and REZ expansions in the north west and central north of Victoria** – AEMO and TransGrid are jointly progressing the VNI West Regulatory Investment Test for Transmission (RIT-T) to assess the economic merits of additional transfer capacity between Victoria and New South Wales from 2027-28.

Two major projects being progressed by neighbouring transmission network service providers (TNSPs) will also impact the Victorian network:

- **New interconnection with Tasmania** – TasNetworks is conducting a RIT-T for the Marinus Link project to deliver up to a 1,500 MW interconnector between Victoria and Tasmania.
- **New interconnection between South Australia and New South Wales** – ElectraNet and TransGrid are progressing Project EnergyConnect to deliver an 800 MW interconnector between their two regions, with a reinforced connection to Victoria at Red Cliffs.

Development beyond the roadmap

AEMO's *Transmission Roadmap for Victoria* includes all projects that are likely to deliver net economic benefits under the current regulatory framework. However, specific developer or community impact considerations may result in generator investment in other parts of the network that are not prioritised in the current transmission roadmap.

As a result, additional system constraints could emerge that curtail the output of some generators or result in challenging connection conditions.

- AEMO believes it prudent to begin pre-feasibility assessments on network projects that support these areas of high developer interest, even before formal trigger conditions have been met.
- AEMO has commenced work on a *REZ Development Plan* in parallel with the VAPR. The *REZ Development Plan* aims to understand how alternative geographic patterns of generator investment might impact the optimal transmission build for Victoria.
- The resulting network limitations and remediation options would allow projects to rapidly progress through the regulatory process when justified, or provide options for third-party investment.

Continuing to adapt

AEMO continues to adapt its regional planning processes to match Victoria's dynamic environment.

- In close collaboration with local NSPs, AEMO has initiated a connections uplift program for delivery over this year. The program will place greater emphasis on clear communication, transparent processes, common methodologies, and improved account management throughout the connection process.
- AEMO is also progressing recommendations from the Renewable Integration Study (RIS), focusing on the need for forward-looking performance standards, and new analysis capabilities to assess system performance under a range of emerging reactive, system strength, inertia, and reverse power flow conditions.
- AEMO is also working to better utilise emerging technologies and include non-traditional and non-network options wherever possible and economic. New technologies have featured strongly in AEMO's recent investment projects, and AEMO continues to partner and support a range of research, development, and technology pilot programs across Victoria.

Performance of the Victorian DSN during 2019-20

While the Victorian DSN remained secure under typical operating conditions, a tightening supply balance, prolific bushfires, extreme weather events, and record minimum demands contributed to a number of security and reliability events.

Notable network performance observations are:

- Minimum operational demand (3,300 MW) occurred in the early afternoon on 1 January 2020; this represented a new minimum record for daytime demand and the second year in a row where the annual minimum has occurred during the afternoon rather than overnight. New minimum demand records have already been set in the first half of 2020-21.
- Daily minimum demands occurred during daylight hours on 51 separate occasions, up from only 12 reported in the previous VAPR, highlighting the impact of increasing distributed PV investment.
- Several terminal stations that have historically behaved as net loads have increasingly behaved as net generation sources due to increases in distribution-connected generation. This year, seven locations experienced reverse flows, up from five locations in 2018-19, with three of these (Wemen, Terang, and Kerang) all transferring supplies into the transmission network for more than 30% of the year.
- While COVID-19 resulted in an approximately 500 MW shift between commercial and residential demand, net daily demand remained relatively consistent with previous years. Time-of-day usage patterns since March 2020 have seen reductions in the typical morning peak and upward pressure into the afternoon. This trend continued to grow across April, May and June 2020.
- Operator interventions were required to manage high voltages on the network during light load conditions, particularly around the Keilor Terminal Station. These actions included de-energising single 500 kilovolt (kV) lines, activating NMAS where economic to do so, and progressing to de-energise a second 500 kV asset on several occasions. One voltage control direction was issued in March 2020. AEMO has progressed a number of investments to address these issues from 2021.

- Maximum operational demand peaked at 9,667 MW on 31 January 2020. At the time, temperatures in Melbourne were almost 42°C, and only 866 MW was available for import from neighbouring states.
- In September 2019, AEMO identified that five solar farms in the West Murray Zone could exhibit voltage oscillations following transmission line faults. In response, AEMO invoked network constraints to reduce generator output and the number of online inverters, while working in parallel with proponents to retune their inverter settings. Testing was completed in April 2020, and the constraints were subsequently lifted.
- In December 2019, AEMO published a notice of fault level shortfall at Red Cliffs Terminal Station, with a magnitude of 312 megavolt amperes (MVA). AEMO has implemented temporary remediation measures, and is progressing procurement activities for a permanent solution.
- A number of extended network outages were required over 2019-20 to accommodate the installation of new renewable generators and control schemes in the north-west of Victoria. These outages resulted in significant periods of constraint on local generators to maintain voltage stability and avoid voltage collapse risks. These constraints are not expected to bind as frequently in future years, with fewer new connection projects expected to proceed on the associated lines.
- There were five security, reliability, or separation events driven by bushfires and extreme weather:
  - On 30 December 2019, 283 megawatt hours (MWh) of emergency reserves were activated in Victoria over 6.5 hours through the Reliability and Emergency Reserve Trader (RERT).
  - On 4 January 2020, a major bushfire event in the Snowy Mountains caused the outage of multiple transmission lines, resulting in a separation event between Victoria and New South Wales.
  - On 10 January 2020, adverse weather conditions associated with bushfires were associated with the trip of the Eildon to Mount Beauty 220 kV lines. At the same time there was a high-impact reclassification in place for the South Morang to Dederang 330 kV lines.
  - On 31 January 2020, a severe convective downburst near Cressy resulted in the collapse of several steel transmission towers, resulting in a separation between South Australia and most of the Victorian network. South Australia remained separated from the National Electricity Market (NEM) until 17 February 2020.
  - On 31 January 2020, 697 MWh of RERT reserves were activated in Victoria. This event coincided with the tower collapse and subsequent separation of Victoria and South Australia
- Two other security events also occurred:
  - On 16 November 2019, spurious signals from telecommunications equipment caused the maloperation of protection equipment and tripping of 500 kV lines between Heywood, Mortlake, and Tarrone, separating Victoria and South Australia.
  - On 2 March 2020, a circuit breaker at Heywood Terminal Station tripped during a prior outage of one Mortlake to Moorabool 500 kV line, resulting in a separation event between Victoria and South Australia. This was classified as a credible contingency event, and equipment operated as designed.

Operational challenges and constraints

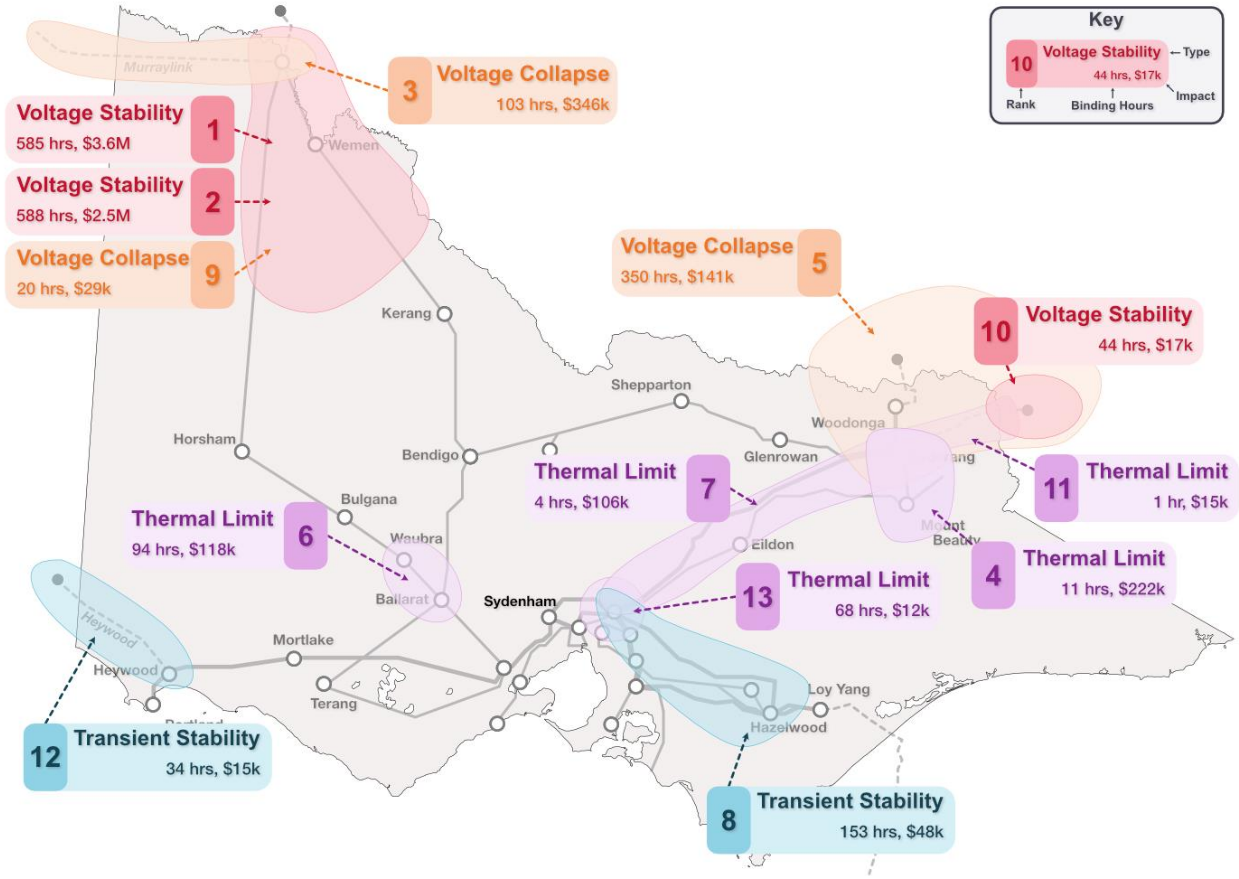
Rapid changes in the technical characteristics and geography of supply resulted in considerable operating challenges during 2019-20, and the need for temporary constraints or new operating arrangements to manage system security. Voltage stability and system strength issues emerged in the north-west of Victoria, which were exacerbated by temporary planned outages required to support new connections.

Figure 1 shows the most significant network limitations on the Victorian DSN over the past year. While these constraints are those with the most significant impact historically, investment to remove any specific constraint would also require consideration of any limits that may bind immediately below. Further investment may be required to address these additional limits to realise maximum market benefits.

For example, while current operation in the north-west of Victoria is dominated by voltage stability limitations, relieving these through network investment will likely see thermal limitations on the 220 kV network begin to bind. The VAPR studies indicate that at times of maximum generation, headroom between the stability and thermal limitations may be as little as 45 MW (hot weather) or 145 MW (cold weather).

Figure 7 summarises a number of limitations that sit beneath historically significant constraints, and wholistic remediation options for these constraints are discussed in Chapter 3, Chapter 4, and Appendix A1.

Figure 1 Historically significant Victorian transmission constraints in 2019-20



- Constraint impact provides its indicative impact on the dispatch outcomes of the NEM. This is used as a relative guide, but does not necessarily reflect the financial impacts on individual generators, or the market benefits available under a RIT-T.
- The top ranked constraint represents a collection of prior outage limitations, that applied during a set of planned network outages required to facilitate new connections in the north-west of Victoria.
- A number of these limitations are being addressed by planned or committed projects in the Victorian transmission roadmap.

Growth in renewable energy

The operational landscape in Victoria is changing rapidly, with strong interest in new renewable generation projects driving the pace of this change. Victoria now has approximately 7.8 GW of existing or committed wind and solar generation, with 2.9 GW of this attributed to distributed PV installations. There are an additional 2.3 GW of existing hydro generation, and 75 MW of existing or committed battery storage[1].

Since the 2019 VAPR, over 1.6 GW of new large-scale renewable projects have connected or commenced commissioning in Victoria, and three new terminal stations have been established in response. There are a further 1.5 GW of renewable projects committed to connect, and almost 16.3 GW of projects have lodged connection enquiries[2]. Much of the growing investor interest is being motivated by the Victorian Government's VRET, which seeks to deliver 40% renewable energy generation by 2025, and 50% by 2030.

Figure 2 summarises Victoria's existing, committed and proposed generation projects.

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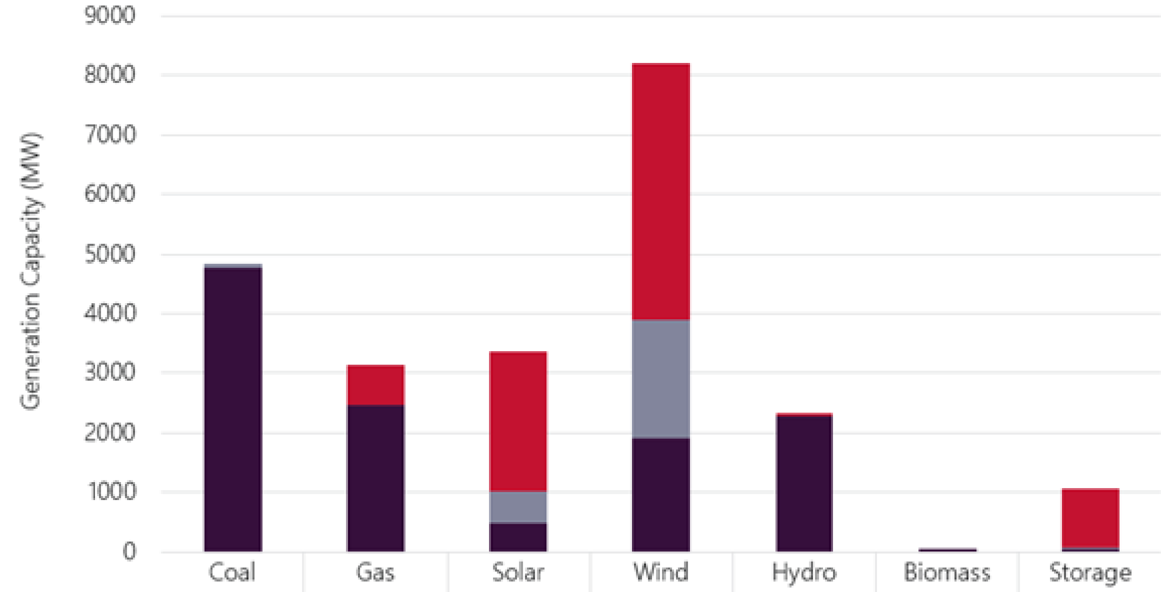
[1] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[2] As at September 2020, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps.

Figure 2 Existing, committed and proposed large-scale generation capacity in Victoria, 20 July 2020



	Coal	Gas	Solar	Wind	Hydro	Biomass	Storage
Proposed		650	2344	4304	34		992
Committed*	60		546	1994			20
In Service	4775	2477	478	1911	2292	58	55

AEMO's 2020 ISP finds that at least 13.2 GW in renewable generation would be required to deliver the VRET under its Central scenario when using the latest demand forecasts (see Figure 3). This represents up to 5.4 GW of additional renewable investment, spread between large-scale and distributed resources. An additional 600 MW of large-scale plant has already become committed since the ISP analysis.

Figure 3 Renewable development by 2029-30, ISP Central scenario with updated demand forecasts

The ISP assumes that renewable generation would be built in locations that take best advantage of existing network capabilities. As an input to this assessment, the ISP identifies six potential REZ candidates in Victoria, and assessed their remaining capacity to accommodate further generator investment (hosting capacity).

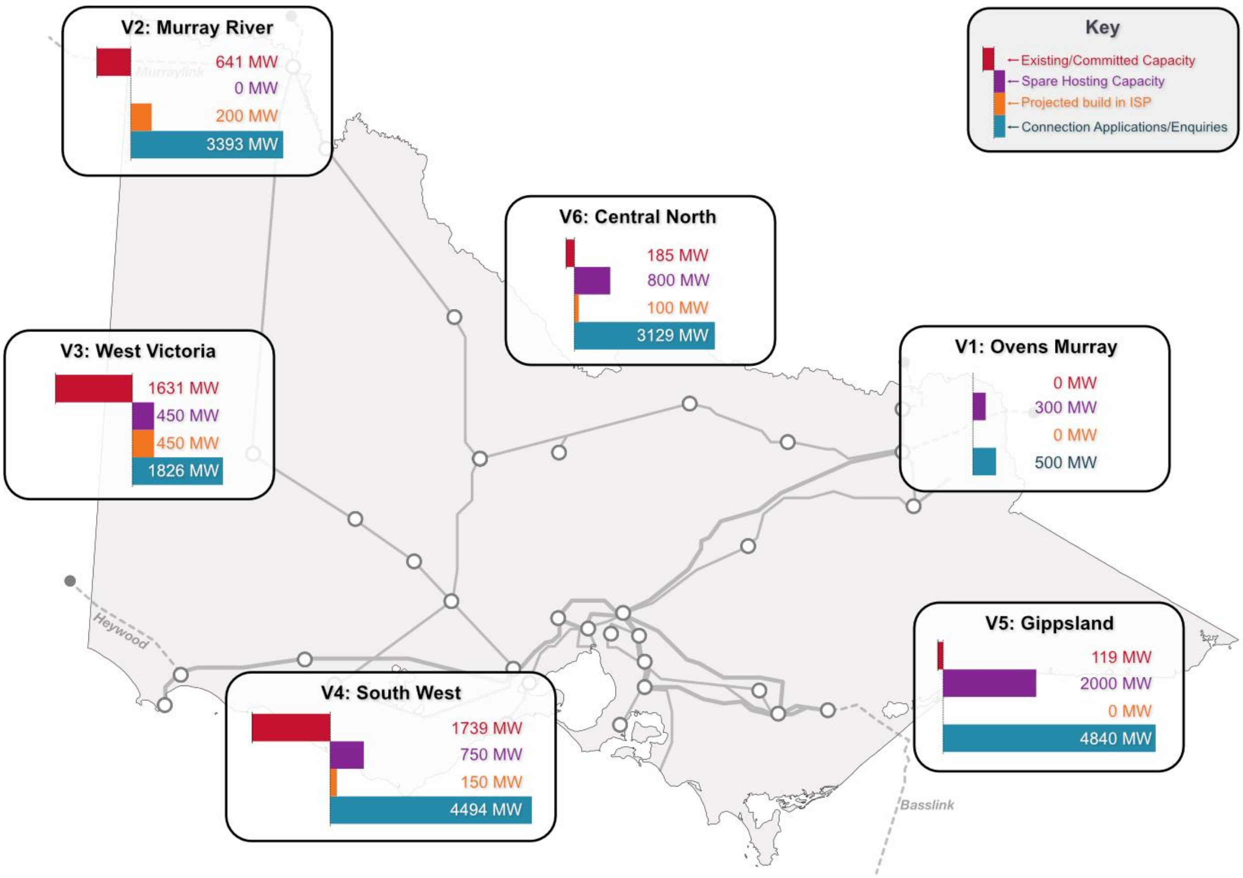
Figure 4 shows the breakdown of these results by REZ and indicates how such build plans overlap with the hosting capacity and generator interest within each zone. In all potential REZs, developer interest exceeds the residual hosting capacity of the system.

The ISP identifies that a least-cost way to meet security, reliability, and policy objectives is to utilise:

- Spare capacity in the South West and Central North REZs.
- Unlocked capacity in the Western Victoria REZ, following delivery of the Western Victoria Transmission Network Project and later the VNI West Project (interconnection with New South Wales).
- Unlocked capacity in the Murray River REZ, following delivery of Project EnergyConnect (interconnection between South Australia and New South Wales).
- Unlocked capacity in the Murray River or Central North REZs, following delivery of the VNI West Project.
- Spare capacity in the Gippsland REZ if VNI West cannot be delivered before 2030.

Under the ISP's Step Change scenario, the model also expanded the South West REZ in 2036-37 by building an additional single circuit 500 kV line between Mortlake and a new terminal station north of Ballarat.

Figure 4 Summary of Victorian REZs under ISP Central scenario with updated demand forecasts



- Capacity values are based on the 2020 ISP, and include only large-scale wind and solar projects. Enquiries are as at September 2020 from the connections map: https://aemo.com.au/-/media/files/electricity/nem/network_connections/maps/vic-map-2020.pdf?la=en.
- The hosting capacity includes the impact of the Western Victoria Transmission Network Project.
- For consistency, the existing and committed capacities shown in the diagram are those that applied in the ISP modelling, although 600 MW of new projects have become committed since the ISP inputs were locked down.

Transmission Roadmap for Victoria

To meet the forecast future needs of the system, AEMO is progressing a suite of projects across the state through its *Transmission Roadmap for Victoria*. This roadmap aligns with the ISP and is designed to deliver Victorian policy, security, and reliability objectives at the lowest system cost but excluding other externalities.

It comprises committed projects (those that have already passed appropriate regulatory approvals), and future projects (those where assessment and approvals are currently underway). Together these projects target key thermal, stability, voltage control, system strength, and REZ expansion projects across the state.

Committed projects

Since the 2019 VAPR, AEMO has concluded several regulatory processes on projects that have now all transitioned into procurement and delivery phases:

- Voltage control – AEMO and AusNet Services have committed to install four 100 MVAr reactors from 2021 to address voltage control limitations under light load conditions.
- REZ expansion – in July 2019, AEMO concluded a RIT-T to reduce network congestion and unlock additional connection hosting capacity in Western Victoria. The Western Victoria Transmission Network Project is now progressing towards staged delivery between 2021 and 2025.
- Interconnection – in February 2020, AEMO and TransGrid concluded a RIT-T to unlock an additional 170 MW of Victorian export capability on the VNI to improve access to renewable generation in the southern states. This project is progressing towards delivery and interregional testing from late 2022.
- System strength – in August 2020, AEMO entered into NMAS agreements with two system strength service providers in the Red Cliffs area to remediate a localised system strength gap[3]. AEMO is currently progressing a long-term solution through a market procurement activity.
- Improved system monitoring – AEMO is progressing the installation of PMUs to provide better visibility of network performance and more accurate models of the power system.
- System Integrity Protection Scheme (SIPS) – at the request of the Victorian Government, AEMO has taken steps to procure a system integrity protection scheme that will increase import capabilities of VNI by up to 250 MW during November to March each year.

Future projects

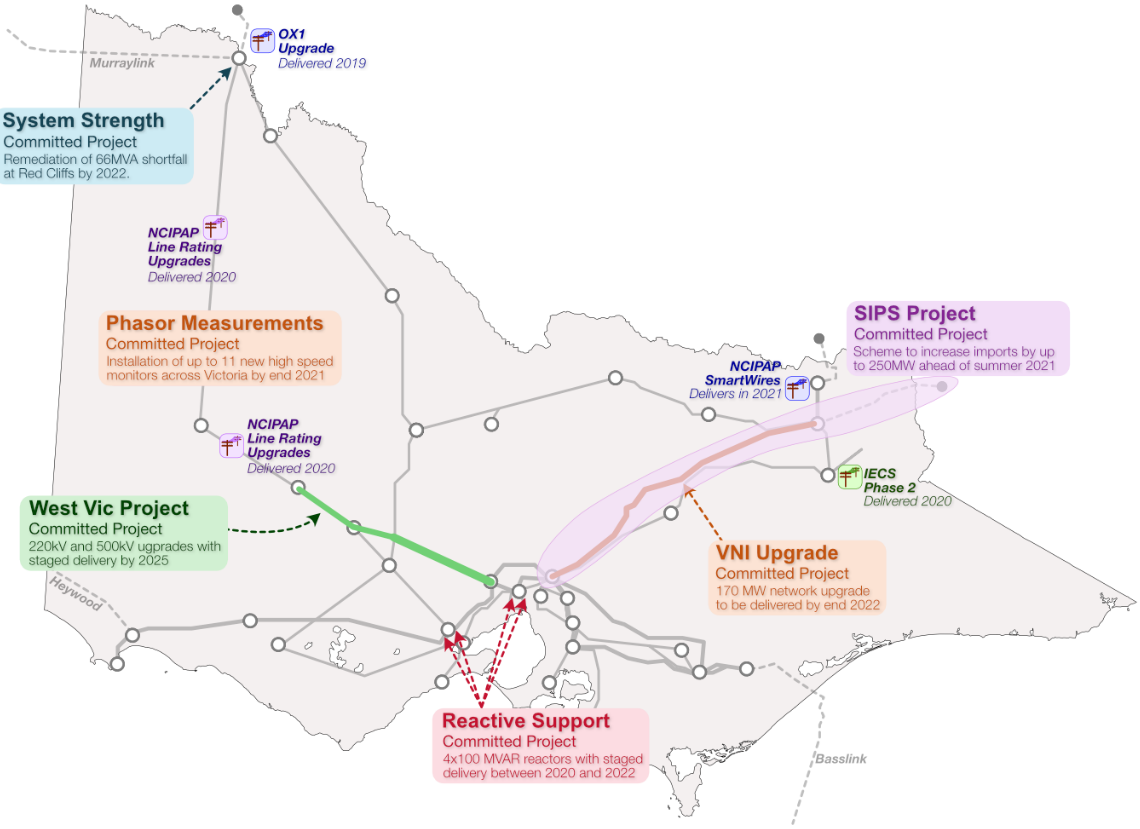
Regulatory investment tests and other approval processes are currently underway for:

- Interconnection and REZ expansion – AEMO and TransGrid are jointly progressing the VNI West RIT-T, to deliver additional transfer capacity between Victoria and New South Wales. This project aims to improve supply reliability, yield more efficient development and dispatch of high-quality renewable resources, and allow more efficient sharing of resources between NEM regions.
- REZ expansion – AEMO is investigating potential network solutions to improve voltage stability issues in the south west transmission corridor to further increase renewable hosting capacity in this REZ.
- Interconnection – projects are also underway in neighbouring regions that integrate with the DSN. These include the 1,500 MW Marinus Link interconnector with Tasmania, and the 800 MW EnergyConnect interconnector between New South Wales and South Australia, with connection to Victoria at Red Cliffs.

Figure 5 and Figure 6 summarise AEMO's 2020 *Transmission Roadmap for Victoria*.

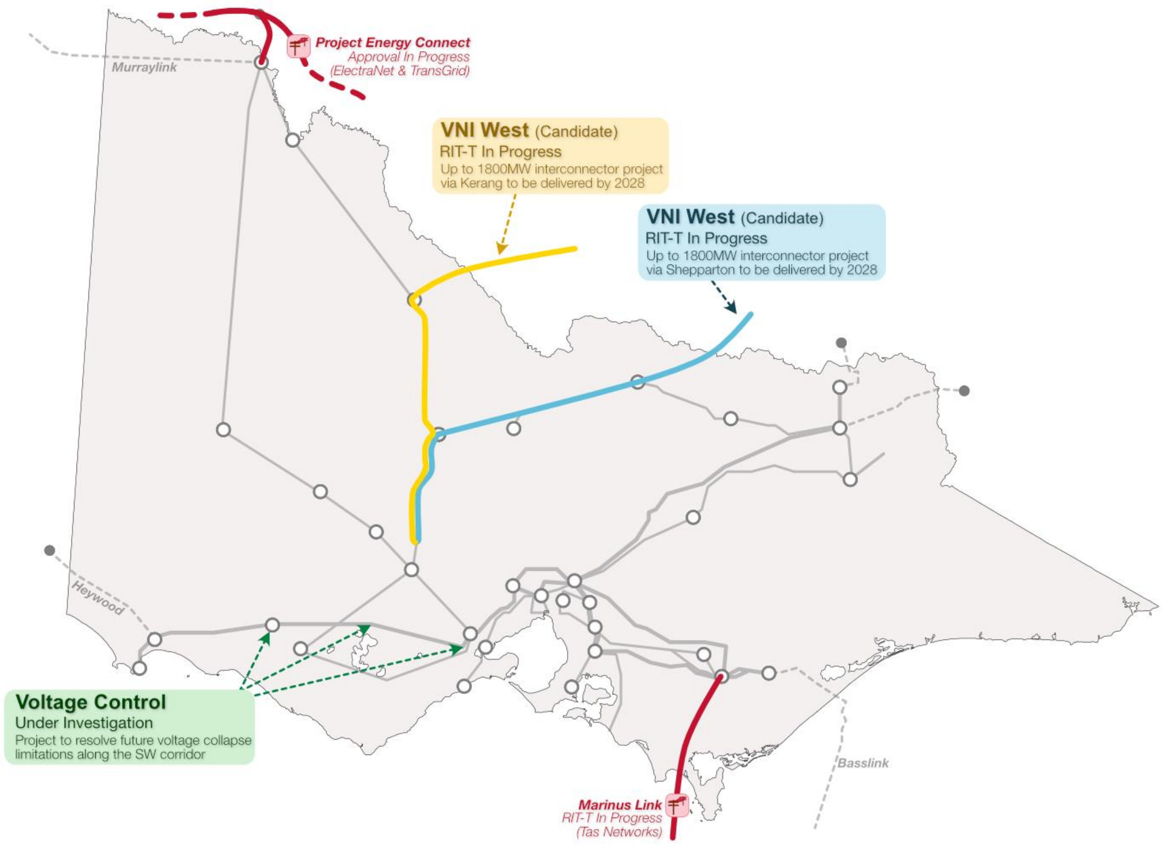
[3] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en&hash=5C3EDDABDF81891B3989F6FF0466C486.

Figure 5 Transmission Roadmap for Victoria – committed and recently delivered projects



NCIPAP: Network Capability Incentive Project Action Plan; IECS: Interconnector Emergency Control Scheme.

Figure 6 Transmission Roadmap for Victoria – further projects under assessment



Identifying new limitations

AEMO's *Transmission Roadmap for Victoria* has been designed to deliver policy, security, and reliability objectives in a least-cost way over the coming decade. This means it is not necessarily designed to remove all network congestion – particularly where generation investments occur in weaker parts of the grid or outside the least-cost development plan considered in the ISP and VAPR.

AEMO proactively identifies future limitations through its operational, planning, and connection functions. When identified, a new limitation will trigger further investigation or prefeasibility studies. Projects are added to the roadmap as they meet regulatory approval hurdles.

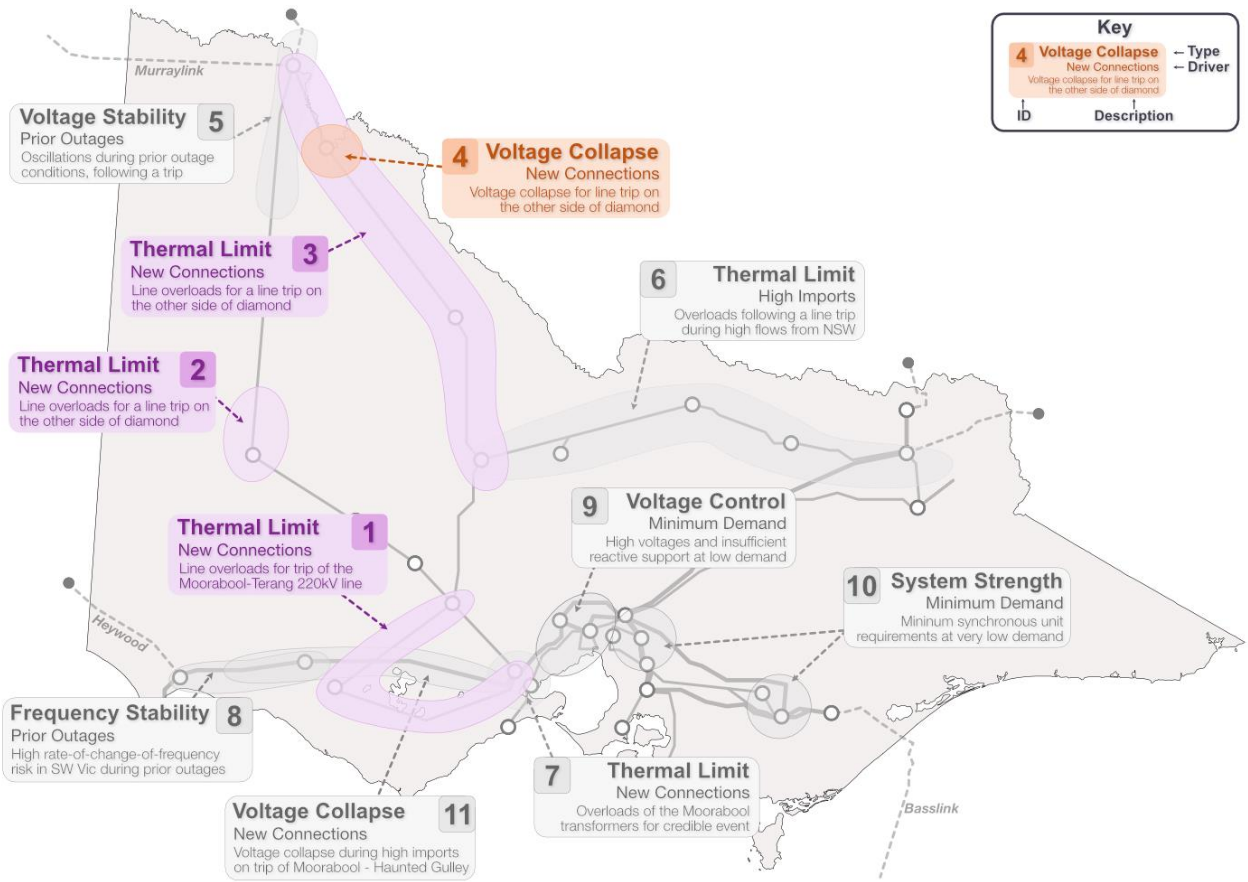
The annual VAPR provides an opportunity to build on these investigations, and undertake a full scan of the Victorian power system. The VAPR uses detailed analysis to capture the nature, timing, impact, and triggers associated with potential limitations. The focus of this work is on identifying projects that are most likely to deliver net economic benefits under the current regulatory framework, while minimising costs to consumers.

Figure 7 presents the key results of the 2020 VAPR engineering assessment, identifying both priority limitations (for which economic mitigations are likely and are being studied), and developing limitations (which may not yet be economic, but for which AEMO is undertaking options analysis or further study).

These constraints were identified as 'monitored' limitations in previous VAPR studies, and have now triggered further study given the latest projections of demand and generator commitment. A number of these are also being mitigated by the committed and future projects identified in the roadmap.

The drivers for each limitation are specified in the figure, and primarily relate to new connections, prior outage conditions, and minimum demand challenges. The impacts of these limitations are already accounted for in the REZ hosting capacities presented in Figure 4.

Figure 7 New priority limitations (coloured) and developing limitations under investigation (grey)



Priority limitations

In 2020, AEMO has identified several limitations with potential economic merits for remediation, and intends to progress these to prefeasibility studies following VAPR publication:

- Overloading of the Ballarat – Terang – Moorabool 220 kV line for a credible contingency (trip of the Moorabool – Terang line), due to new connections. A Network Capability Incentive Project Action Plan (NCIPAP) project is in progress to alleviate this limitation from December 2020, and AEMO is investigating further post-contingent tripping schemes.
- Overloading of the Horsham – Murra Warra 220 kV line for a credible contingency (trip of the Bendigo – Kerang line), due to new connections between Horsham and Kerang. AEMO is investigating the potential benefits of implementing a post-contingent generation tripping scheme.
- Overloading of the Red Cliffs – Wemen – Kerang – Bendigo 220 kV line for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line), due to new connections between Kiamal and Kerang. A NCIPAP project is in progress to alleviate this limitation from August 2021, and AEMO is investigating further post-contingent control schemes.
- Voltage instability/collapse around Wemen Terminal Station for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line), due to new connections between Kiamal and Wemen. AEMO is investigating a low-cost post-contingent tripping scheme to alleviate this limitation.

Developing limitations

Several new limitations have also moved to further analysis or investigation following the 2020 VAPR analysis:

- Voltage oscillation in western and north-western Victoria during prior outages.
- High overloading of the Dederang – Glenrowan – Shepparton – Bendigo 220 kV line for a credible contingency (trip of one of the other Dederang – Glenrowan 220 kV lines), due to high New South Wales to Victoria imports.
- High overloading of either Moorabool 500/220 kV transformer for a credible contingency (tripping of the other Moorabool 500/220 kV transformer), due to additional generator connections on the 500 kV lines west of Moorabool Terminal Station (MLTS), which may require generators on these lines to be constrained.
- High rate of change of frequency (ROCOF) in south-west Victoria requiring constraining of generators on the 500 kV lines west of MLTS during prior outages of one of the 500 kV lines west of MLTS for a credible contingency (trip of one of the 500 kV lines west of MLTS).
- High voltages in Metropolitan Victoria and South West Victoria caused by low demand conditions forecast by the 2020 *Electricity Statement of Opportunities* (ESOO) for the NEM and possible withdrawal of a large load.
- Minimum fault level requirements at Thomastown and Loy Yang terminal stations caused by lower demand or potential early retirement of thermal generation.
- AEMO is investigating the potential of a new voltage collapse limitation in South West Victoria (tripping of the Moorabool – Haunted Gully 500 kV line), due to additional generator connections and under high import from South Australia.

Other limitations

AEMO has also reviewed Victoria's voltage control, inertia, and system strength requirements, finding that:

- The reduced minimum demand levels projected in the 2020 ESOO will require further investment in reactive plant to manage high voltages. The timing of this additional investment is currently in the second half of the 10-year study horizon, accounting for the 4 x 100 MVAR new reactors being installed in 2021 and 2022. However, this could be accelerated by the retirement of any large industrial loads. AEMO will continue to track demand trends, trigging investments before they create operational impacts.

- Falling minimum demand is likely to lead to periods where renewable generation has to be constrained to ensure Victoria retains a minimum number of online synchronous generators. This could also reduce the effectiveness of under frequency load shedding (UFLS) schemes. AEMO will continue to monitor how actual demand and operating conditions are tracking against forecast, while exploring alternative technology solutions to system strength issues. Further analysis is underway through AEMO's 2020 *System Strength and Inertia Review*, to be published by the end of the year.
- Victoria's strong interconnection with neighbouring regions makes islanded operation less likely than for other regions, and no inertia shortfalls are currently projected ahead of generator closures in the Latrobe Valley. However, following several partial islanding events since the 2019 VAPR, AEMO is investigating this further through its 2020 *System Strength and Inertia Review*. The VNI West project is likely to further strengthen interconnection and reduce Victorian inertia risks late in the decade.
- Aside from the previously declared system strength shortfall at Red Cliffs, no new shortfalls are currently forecast for the next five years. This assumes all future generator proponents will remediate their own system strength impacts through 'do-no-harm' provisions. The next expected TNSP shortfall is likely to coincide with the emerging minimum synchronous unit constraints (mentioned above), or with retirement of the Yallourn Power Station (currently scheduled progressively in 2029-32).

Limitations in this list may not yet be economic to pursue, but AEMO continues to track these and will trigger further action when system conditions change, or specific generator investment patterns develop. Appendix A1 provides further details on each limit, and its trigger conditions.

Planning beyond the current roadmap

AEMO's *Transmission Roadmap for Victoria* includes all projects that will deliver system requirements and legislated policy targets in the least-cost way, as prescribed under the current regulatory framework. However, there continues to be strong developer interest beyond the least-cost expansion plan, often driven by locations with excellent renewable resources. As a result, it is likely that new generator investment will continue to test the system's capabilities in weaker parts of the network, and new system constraints could emerge that result in delays to the connection process, or curtail the output of some renewable generators.

The current regulatory framework assigns these risks directly to individual generators and developers as 'locational signals' that should encourage investment in more optimal locations from a network perspective. Experience to date has shown that these signals are not always sufficient to guide investments.

The long lead times associated with delivering transmission infrastructure can also result in extended generator constraints when imbalances between network and generation investment emerge. This could lead to less efficient utilisation of the state's renewable resources, or higher risk premiums that could be passed through into electricity market prices.

To pro-actively address these issues, AEMO believes it is prudent to begin pre-feasibility assessments on potential system improvement projects that would strengthen those areas with high developer interest, even before formal trigger conditions have been met. To this end, in parallel with the VAPR, AEMO has commenced a *REZ Development Plan* study, which it aims to publish in mid-2021.

The *REZ Development Plan* study will seek to understand how continued renewable investment, especially in areas with high quality resources, could impact the required transmission build for Victoria. It will identify projects that could progress through the regulatory process if justified, or that could be available for third-party investment outside of the existing regulatory framework.

Any investment in transmission infrastructure needs to carefully balance the needs and risks of both generators and consumers to ensure optimal economic outcomes and market benefits as a whole. Done well, developers will have access to robust network infrastructure that allows efficient use of local resources, and consumers will benefit from enhanced system security, reliability, and market competition.

Continuing to adapt

The VAPR and *REZ Development Plan* together form the cornerstone of AEMO's strategy to provide a resilient Victorian system that delivers lower-cost outcomes for consumers. AEMO is continuing to adapt its regional planning processes to keep pace with Victoria's dynamic regulatory, environmental, operational, technological, policy changes and investment drivers.

As part of this process, AEMO has initiated a connections uplift program. This program will place greater emphasis on clear communication, transparent process, common methodologies and improved account management. It is being delivered across five different workstreams:

- **Resources and skills** – implementing an uplift in resourcing to ensure the right skills and adequate resources are available to assist proponents get their project connected. This stream includes close engagement with industry partners to build a common approach to the connections process and requirements.
- **Connections process improvement** – standardising the process for assessing connections to improve consistency and develop stronger advisory support for complex performance issues, where requested by proponents.
- **Account management** – continuing to assign dedicated account and project managers to projects, but with increased support through a high-quality customer relationship management (CRM) system. Improved project tracking will provide greater visibility of project progress.
- **Novel solutions** – working with industry to develop and test new technology solutions, and where possible, common approaches to emerging technical issues such as declining system strength.
- **Enhanced measurement and modelling** – working closely with NSPs and proponents to continue to validate and improve system and generator models. This will include additional measurement capabilities in strategic location, standardised models and assessment cases.

The large-scale deployment of inverter-based generation in weak parts of the network has pushed the system into previously uncharted territory, and requires AEMO to conduct detailed Electromagnetic Transient (EMT) studies to identify and address potential system issues. EMT modelling is now an essential part of most connection studies, and is becoming increasingly necessary for mid-term planning. AEMO has continued to develop and benchmark its multi-region wide-area models, and is working to build out its internal modelling infrastructure and expertise.

To help proponents adapt to these increasing modelling requirements, AEMO is developing an industry modelling platform that would provide access to a detailed EMT simulation environment while also protecting confidential information contained in many of the generator models. This new platform aims to provide connection applicants with the ability to design, tune and validate their own plant models ahead of (or in parallel with) the connections process.

In network planning, a trend towards high DER and negative minimum demands will present unprecedented challenges. AEMO is progressing a number of recommendations from the RIS, with a focus on the need for forward-looking performance standards, the controllability of distribution-connected supplies, and the need for new analysis capabilities to assess system performance under a range of emerging reactive, system strength, and reverse power flow conditions.

Many of these challenges cannot be resolved by traditional solutions, and AEMO looks forward to working closely with industry to identify new ways of solving the issues identified in this report, maximise the use of emerging technologies, and promote the use of non-network options where this is possible and economic.

Contents

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1. Introduction

This chapter introduces the purpose and content of the 2020 *Victorian Annual Planning Report* (VAPR), including the key regulatory, policy, operational, network, and connections context in which the report has been prepared.

Purpose of the 2020 VAPR

The Australian Energy Market Operator (AEMO) is responsible for planning and directing augmentation on the Victorian electricity transmission Declared Shared Network (DSN). The VAPR assesses the adequacy of the DSN to meet reliability and security needs over the coming 10 years, while also supporting the efficient delivery of government policy, adapting to the changing nature of demand, and considering changes in the geography and characteristics of supply.

The VAPR studies provide insights relating to network security, reliability of supply, forecast demand, network capability, system performance, and emerging network development needs, with a particular focus on those most likely to deliver net economic benefits and lower costs for consumers.

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

In the 2020 VAPR:

- Chapter 2 reviews the performance of the DSN throughout 2019-20, including new operational challenges, notable power system incidents, and the performance of the network under a range of operating conditions.
- Chapter 3 provides an update on the network investment activities and investigations that have progressed since June 2019 to facilitate the integration of new renewable generation while supporting Victorian power system security and reliability.
- Chapter 4 explores potential new emerging limitations that may reduce system performance, impact efficient asset utilisation, or result in additional network constraints. Identified limitations may warrant heightened monitoring, further options analysis, or trigger the need for investment.
- Chapter 5 presents updated information on AusNet Services' Asset Renewal Plan, outlining expected network asset retirements, deratings, and renewals within the VAPR timeframe, including AEMO's assessment of the future network needs associated with these assets.
- Chapter 6 provides a range of insights into future transmission planning in the Victorian DSN, considering both current and emerging trends in technology, geography, and demand-side behaviour. The chapter provides a range of information to assist new and intending participants to better understand the changing investment landscape in Victoria.

The 2020 VAPR is also supported by an online interactive map 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 2020 VAPR

The context for network development is changing rapidly, both nationally and regionally, with multiple moving pieces across regulatory, policy, operational, network and connection areas. Figure 8 summarises the key context areas that are each explored in more depth through the remainder of this chapter.

Figure 8 Key context areas for the 2020 VAPR

Policy and regulatory	Operational challenges	Network investment	Renewable connections
•National Planning Framework •*National Electricity Victoria Act* (NEVA) •Renewable energy targets and initiatives •Regulatory changes	•Extreme weather •Minimum demand •System strength •Voltage stability •COVID-19 Impacts	•Western Victoria •VNI upgrade •Reactive power •VNI West •EnergyConnect •Marinus Link	• 5 GW existing • 2 GW committed • 12 GW enquiry •Some already facing economic and technical challenges

1.1.1 Policy and regulatory context

Policy and regulatory changes have a significant impact on the justification for existing network projects, the identification of newly emerging limitations, and the changing nature of planning in the DSN.

Renewable energy targets and initiatives

Federal and state governments have made several policy announcements and commitments that are impacting on the drivers for, and economics of, investment in the Victorian network. These include:

- The Victorian Government has commenced stage 2 of its Solar Homes program, providing a rebate of up to $1,000 on solar hot water systems from 1 July 2019[4], which reduces Victoria's effective demand.
- The Victorian Government has committed to a Victorian Renewable Energy Target (VRET) of 40% by 2025, with a further target of 50% by 2030[5]. The first round of VRET auction winners were announced in 2019, and a potential second round was announced in August 2020.
- The Tasmanian Government released a draft Tasmanian Renewable Energy Action Plan that targets 200% renewable generation by 2040[6], driving a need for further interconnection between Tasmania and Victoria.
- The Federal Government has continued its support for the Snowy 2.0 generation project, with the project targeting commissioning by 2025-26[7]. This project will place additional focus on the merits of augmenting the network between Snowy, Sydney, and Melbourne.

National Electricity Victoria Act (NEVA)

The Victorian Parliament has amended the *National Electricity Victoria Act* (NEVA), to allow priority augmentation projects to be fast-tracked with respect to the Victorian Declared Transmission System[8].

The Victorian Government has also requested that AEMO take steps to procure a 250 megawatt (MW) System Integrity Protection Scheme (SIPS) ahead of summer 2021-22[9].

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[4] See https://www.solar.vic.gov.au/.

[5] See https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

[6] See https://www.stategrowth.tas.gov.au/__data/assets/pdf_file/0011/241112/TREAP.PDF.

[7] See https://www.snowyhydro.com.au/snowy-20/about/.

[8] See https://www.legislation.vic.gov.au/as-made/acts/national-electricity-victoria-amendment-act-2020.

[9] See https://aemo.com.au/en/initiatives/major-programs/victorian-government-sips-2020.

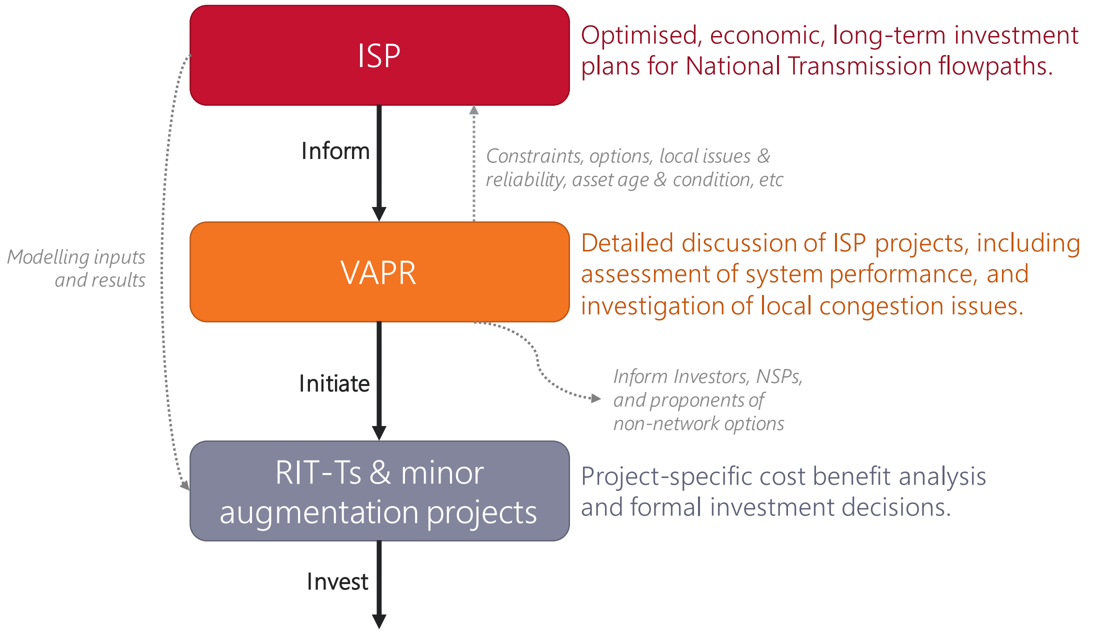
The national planning framework

AEMO, the Council of Australian Governments (COAG), and the Energy Security Board (ESB) have jointly progressed changes to the national planning framework to create a more actionable *Integrated System Plan* (ISP). These reforms implement a streamlined regulatory framework that allows outputs from the ISP to be incorporated into transmission network service provider (TNSP) investment decisions.[10] Under this approach:

- Comprehensive system-wide modelling in the ISP identifies network needs and a set of options that deliver the highest net market benefits when considered nationally, and as part of an optimised plan.
- The VAPR then leverages these nationally optimised plans, and overlays them with more granular information about local congestion issues and regional performance characteristics.
- 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 subsequent publications.

Together, the ISP and the VAPR initiate the Regulatory Investment Test for Transmission (RIT-T) process, which then aims to validate project benefits, explore lower-cost variations, and ensure that any subsequent investment decision is robust and transparent. This relationship is presented in Figure 9.

Figure 9 Relationship between the ISP, VAPR, and RIT-T in the national planning framework



Regulatory changes and processes

The following regulatory processes also impact on AEMO's operational and investment activities:

- The Victorian Government sought a jurisdictional derogation[11] that allows AEMO to contract emergency reserves under the Reliability and Emergency Reserve Trader (RERT) mechanism on a multi-year basis. The derogation was replaced by ESB rule changes introducing an interim reliability measure (IRM)[12].
- The Australian Energy Market Commission (AEMC) is investigating the effectiveness of system strength frameworks in the NEM[13], and will consider the appropriateness of existing obligations on NSPs and

[10] See http://www.coagenergycouncil.gov.au/publications/actionable-isp-final-rule-recommendation.

[11] See https://www.aemc.gov.au/rule-changes/victorian-jurisdictional-derogation-rert-contracting.

[12] See http://www.coagenergycouncil.gov.au/reliability-and-security-measures/interim-reliability-measures.

[13] See https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem.

connecting generators when managing system strength. The AEMC published a consultation paper in July 2020, seeking stakeholder feedback on several of the proposed Rule changes.

1.1.2 Operational context

Impacts of the COVID-19 pandemic

The impacts of COVID-19 are continuing to be realised across the globe, with impacts on international economies, exchange rates, commodity prices, production lines, and domestic patterns of consumer behaviour and demand.

Recovery may be slow, and a 'new normal' could be reached with consequences on network operation, maintenance planning, and the cost or timing of investment decisions in the Victorian transmission system. Section 2.7 provides a summary of the operational impacts observed so far this year.

Increasing operational challenges

Environmental factors, coupled with increasing complexity in the Victorian system, have resulted in a growing set of unique operating challenges that are further explored in Chapter 2. In particular:

- Extreme weather events and bushfires over the past 12 months have resulted in infrastructure damage and periods of low reserve that required activation of RERT.
- Secure operation in minimum demand conditions remains a high priority, and voltage control issues at these times have emerged faster than anticipated. Short-term operational measures, such as de-energising transmission lines, have been successfully applied under some conditions. However, more onerous operator interventions have also been required on several occasions. AEMO is progressing interim and long-term solutions through both operational and planning timeframes to address this growing issue.
- Detailed system strength studies are progressing NEM-wide, and have identified several weaker nodes. In December 2019, AEMO published a Notice of Victorian Fault Level shortfall at Red Cliffs[14], declaring an immediate Victorian system strength gap. AEMO executed contracts with two system strength service providers in August 2020 as an interim measure, and has initiated a subsequent tender process to procure a long-term solution.
- Limitations in the north-west of Victoria during forced or planned outage conditions continue to present stability risks and maintenance planning challenges for the area.
- Emerging voltage oscillation and voltage collapse issues are being investigated on the 500 kilovolt (kV) network in the south west of the state, and in the 220 kV network in the north west. These may signal the need for remediation investment or new control schemes to efficiently manage voltage stability for current and anticipated generation in these parts of the network. These issues also highlight the need for investment in high-speed monitoring across the system.
- The potential withdrawal of major industrial load or thermal generation over the coming years will present challenges for voltage control, stability, and system strength, resulting in consequential network needs, and opportunities for new investment or new technology solutions.

1.1.3 Network investment

Since the 2019 VAPR, AEMO has made significant progress across a range of network planning and investment activities, with many of these either successfully completing or progressing significantly through the regulatory testing process.

The 2020 VAPR explores the progress and significance of these developments in Chapter 3, and discusses ongoing works to maintain and refurbish the existing transmission network in Chapter 5.

[14] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2019/notice_of_victorian_fault_level_shortfall_at_red_cliffs.pdf?la=en.

Committed projects

Key investment projects that became committed in the last 12 months are:

- In July 2019, AEMO published its Project Assessment Conclusions Report (PACR)[15] for the Western Victorian Transmission Network RIT-T, and has now engaged AusNet Services to progress delivery of staged network upgrades by 2025.
- In December 2019, AEMO published its PACR for the Reactive Power Support RIT-T[16], and has now engaged AusNet Services to deliver new reactive devices at Moorabool and Keilor terminal stations. In response to significant declines in minimum demand projections, AEMO has sought accelerated delivery of these works by 2022.
- In February 2020, AEMO and TransGrid jointly published a PACR for the Victoria to New South Wales Interconnector (VNI) (minor) upgrade[17]. Both companies are now progressing with procurement and implementation of interconnector upgrades ahead of summer 2022-23.

Projects currently being assessed

Key investment projects that have entered or progressed regulatory testing in the last 12 months are:

- ElectraNet and TransGrid have continued to progress approvals for Project EnergyConnect, which represents a new 800 MW interconnector project between South Australia and New South Wales, with an upgraded connection to Victoria between Bulgana and Red Cliffs. Both parties are finalising their regulatory approval processes.
- In December 2019, TasNetworks published a Project Assessment Draft Report (PADR) for the Marinus Link RIT-T[18], which assesses the economic merits of a second Bass Strait interconnector to leveraging renewable resources in Tasmania.
- In December 2019, AEMO and TransGrid jointly published a Project Specification Consultation Report (PSCR) as the first stage of the VNI West RIT-T[19]. This project was further supported by the final ISP in July 2020 (see below), and detailed power system studies and economic analysis is underway to allow PADR publication in Q1 2021.
- In January 2020, TransGrid published a PADR for the HumeLink project[20] to strengthen transmission capabilities between the Snowy region and Sydney. While this project is not in Victoria, it has a significant impact on the potential benefits of interconnection between the two states.
- In July 2020, AEMO published the 2020 ISP[21], which provides an integrated roadmap for the efficient development of the NEM over the next 20 years and beyond. The 2020 report confirms the need for and importance of progressing the VNI West RIT-T to expand interconnector capability between Victoria and New South Wales while unlocking additional renewable generation capacity. The ISP gives this project an optimal augmentation delivery timing of 2027-28.

  The 2020 ISP also confirms that, subject to construction of the new network projects in the ISP's optimal development plan, Victoria's current VRET target can be met or exceeded, provided generation connections take optimal advantage of the existing network.

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[15] See https://aemo.com.au/initiatives/major-programs/western-victorian-regulatory-investment-test-for-transmission/reports-and-project-updates.

[16] See https://aemo.com.au/initiatives/major-programs/victorian-reactive-power-support-regulatory-investment-test-for-transmission.

[17] See https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-upgrade-regulatory-investment-test-for-transmission.

[18] See https://www.marinuslink.com.au/rit-t-process/.

[19] See https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission.

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

[21] See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

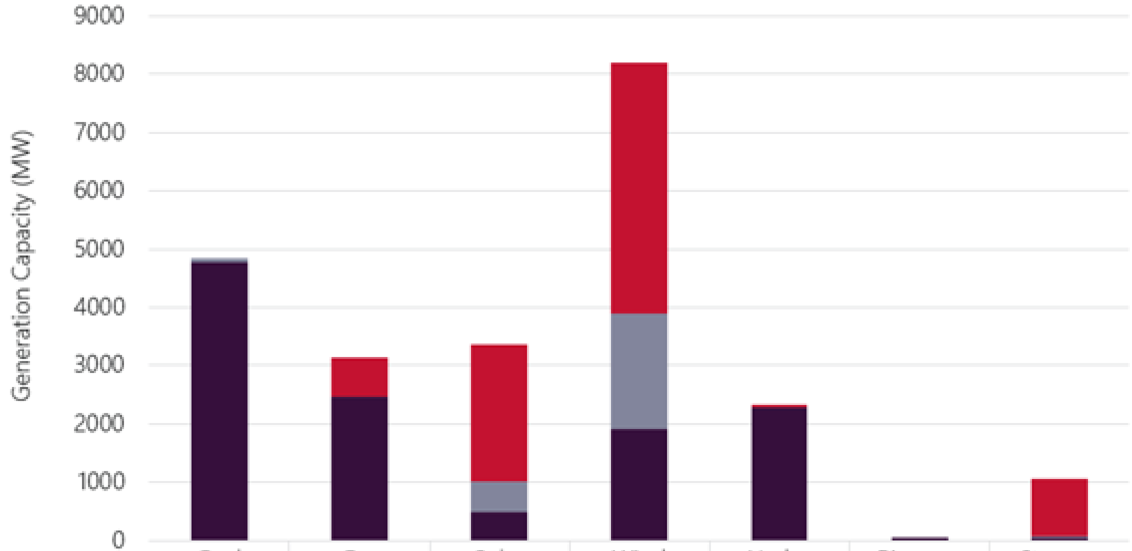
1.1.4 Volume of renewable connections

The Victorian fuel mix is rapidly changing as the state transitions to higher levels of renewable energy. Grid-connected renewable generation in Victoria totals almost 4.6 gigawatts (GW), and accounts for 38% of the state's total generation capacity. This is in addition to the estimated 2.9 GW of distributed photovoltaic (PV) generation installed behind the meter in Victoria[22].

Over 1.6 GW of renewable projects have connected since publication of the 2019 VAPR, and are now either in full service or undergoing commissioning tests. Three new terminal stations have been established in response. There are a further 1.5 GW of projects committed, and another 16 GW have lodged connection enquiries[23].

Figure 10 summarises Victoria's existing, committed and proposed generation projects[24].

Figure 10 Existing, committed and proposed large-scale generation capacity in Victoria, 20 July 2020



	Coal	Gas	Solar	Wind	Hydro	Biomass	Storage
Proposed		650	2344	4304	34		992
Committed*	60		546	1994			20
In Service	4775	2477	478	1911	2292	58	55

Note: Committed projects include those projects currently undergoing the commissioning process.

Many of these new projects are proposed in western parts of the state where high-quality solar and wind resources are abundant. However, this is putting significant stress on the transmission network in these areas. A number of investors are already facing economic and technical challenges associated with connection to weaker parts of the transmission network, including thermal constraints, stability issues, diminishing marginal loss factors (MLFs)[25] and substantial system strength remediation costs.

Chapter 2 discusses the historical performance of the network and the emergence of these new challenges, while Chapter 4 takes a forward-looking view at how these limitations may change over time as new network investment is delivered. Chapter 6 discusses how AEMO is adapting its planning and connections processes to adapt to the changing nature of supply and demand in the state.

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[22] Data as at 30 June 2020 from Clean Energy Regulator Database: http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

[23] As at September 2020, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps.

[24] AEMO, Generation Information webpage, Victoria update 20 July 2020, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[25] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

1.2 Supporting material

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

Unless otherwise indicated, all files are published alongside the VAPR report on the AEMO website[26].

Table 1 2020 VAPR supporting resources

Resource	Description
Historical DSN rating and loading workbook	Presents ratings and loadings for the 2019-20 maximum demand and high export periods presented in Chapter 2 and the interactive map.
AusNet Services 2020 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.
Asset related datasets	• Transmission connection point data for each transmission terminal station where primary station assets are associated with an actual or forecast emerging network limitation. • Transmission line segment data for each transmission line between terminal stations that are associated with a historical or emerging line capacity limitation. • 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.
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. At https://www.aemo.com.au/aemo/apps/visualisations/map.html.
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. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams.
Demand forecasts	AEMO's independent connection point forecasts for Victoria. Detailed information on the forecasts, together with the forecast methodology and recent changes can be found in AEMO's website. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-connection-point-forecasting/victoria. The transmission connection point planning report, prepared by the Victorian Distribution Network Service Providers (DNSPs), provides information on historical and forecast demand, including DNSP's terminal station demand forecast (TSDF) and the causes of differences between these and AEMO's connection point forecasts for Victoria. At https://www.unitedenergy.com.au/wp-content/uploads/2019/12/2019-Transmission-Connection-Planning-Report.pdf.

[26] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

2. Network performance

This chapter reviews the performance of the Victorian DSN throughout 2019-20, including new operational challenges, notable power system incidents, and the performance of the network under a range of operating conditions.

Key network performance observations

While the Victorian DSN remained secure under typical operating conditions, a tightening supply balance, prolific bushfires, extreme weather events, and record minimum demands contributed to a number of security and reliability events. Notable network performance observations are that:

- Minimum operational demand (3,300 MW) occurred in the early afternoon on 1 January 2020, representing a new minimum record for daytime demand, and the second year in a row where the annual minimum has occurred during the afternoon rather than overnight. New minimum demand records have already been set in the first half of 2020-21.
- Daily minimum demands occurred during daylight hours on 51 separate occasions, up from only 12 reported in the previous VAPR, highlighting the impact of increasing distributed PV investment.
- Several terminal stations that have historically behaved as net loads have increasingly behaved as net generation sources due to increases in distribution-connected generation. This year, seven locations experienced reverse flows, up from five locations in 2018-19, with three of these (Wemen, Terang, and Kerang) all transferring supplies into the transmission network for more than 30% of the year.
- While COVID-19 resulted in an approximately 500 MW shift between commercial and residential demand, net daily demand remained relatively consistent with previous years until Stage 4 restrictions further reduced commercial demand. Time-of-day usage patterns since March 2020 have seen reductions in the typical morning peak, and upward pressure into the afternoon.
- Operator interventions were required to manage high voltages on the network during light load conditions, particularly around the Keilor Terminal Station. These actions included de-energising single 500 kV lines, activating Non-Market Ancillary Services (NMAS) where economic to do so, and progressing to de-energise a second 500 kV asset on several occasions. AEMO has progressed a number of investments to address these issues from 2021.
- Maximum operational demand peaked at 9,667 MW in the late afternoon on 31 January 2020. Temperatures in Melbourne were almost 42°C at the time, and only 866 MW was available for import from neighbouring states.
- In September 2019, AEMO identified that five solar farms in the West Murray Zone produced voltage oscillations following a transmission line fault. In response AEMO invoked constraints to reduce the output of these units, and worked in parallel with proponents to retune their inverter settings. The testing was completed in May 2020, and the associated constraints were subsequently lifted.
- In December 2019, AEMO published a notice of immediate fault level shortfall at Red Cliffs Terminal Station, with a magnitude of 312 megavolt amperes (MVA). AEMO has implemented temporary remediation measures, and is progressing procurement activities for a permanent solution.

- A number of extended network outages were required over 2019-20 to accommodate the installation of new renewable generators and control schemes in the north-west of Victoria. These outages resulted in significant periods of constraint on local generators to maintain voltage stability but are not expected to bind as frequently in futures, with fewer connections expected on the associated lines.
- There were five security, reliability, or separation events driven by bushfires and extreme weather:
  - On 30 December 2019, 283 megawatt hours (MWh) of emergency reserves were activated in Victoria over 6.5 hours through RERT.
  - On 4 January 2020, a major bushfire event in the Snowy Mountains caused the outage of multiple transmission lines, resulting in a separation event between Victoria and New South Wales.
  - On 10 January 2020, adverse weather conditions associated with bushfires were associated with the trip of the Eildon to Mount Beauty 220 kV lines.
  - On 31 January 2020, a severe convective downburst near Cressy caused the collapse of several transmission towers, resulting in a separation between South Australia and the Victorian Network.
  - On 31 January 2020, 697 MWh of RERT reserves were activated in Victoria. This event coincided with the tower collapse and subsequent separation of Victoria and South Australia
- Two other security events also occurred:
  - On 16 November 2019, false signals caused the maloperation of protection equipment and tripping of 500 kV lines between Heywood, Mortlake, and Tarrone, separating Victoria and South Australia.
  - On 2 March 2020, a circuit breaker at Heywood Terminal Station tripped during a prior outage of one Mortlake to Moorabool 500 kV line, resulting in a separation event between Victoria and South Australia. This was classified as a credible contingency event, and equipment operated as designed.

2.1 How does AEMO assess network performance?

In evaluating the adequacy of the Victorian DSN, AEMO considered the following key performance indicators:

- **Notable power system incidents** – the frequency of incidents which resulted in system security violation or loss of customer load or generation (Section 2.2).
- **Supply-demand adequacy** – the extent to which the operation of the network facilitated or hindered the ability of the power system to meet customer demand (Section 2.3).
- **Interconnector capability** – the extent to which the operational and design limits of interconnectors restricted the import and export of generation (Section 2.4).
- **Operational challenges** – how network operation was impacted by the changing technical characteristics and geography of supply, particularly where such changes increased operational complexity (Section 2.5).
- **Impact of constraint equations** – the severity of network constraints (Section 2.6).
- **Impact of COVID-19** – the effects of COVID-19 restrictions on the network (Section 2.7).
- **Behaviour of the transmission network at time of high network stress** – the network's ability to supply demand at times of high demand, and maintain voltages at times of low demand (see Section 2.8).

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 distributed PV systems.
- Demand and consumption are as generated, meaning they include generator auxiliary loads[27].

[27] For further information on demand and consumption definitions, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/demand-terms-in-emms-data-model.pdf?la=en&hash=72FA78488ED638F1A00A8C9AF80D303C.

2.2 Victorian power system reviewable operating incidents

AEMO plans, designs, and maintains the Victorian DSN to meet system normal conditions and to remain secure following any single credible contingency event.

Over the review period (1 April 2019 to 30 June 2020), the DSN was operated in a secure state except during the reviewable operating incidents in Table 2. Reviewable operating incidents[28] include significant non-credible events and events where the power system is not in a secure operating state.

The AEMO website contains further information on reviewable operating incidents[29]. AEMO also continues to review the probability and severity of such events to refine its *Victorian Electricity Planning Approach*[30].

This section does not consider distribution network events that may have also resulted in a loss of supply.

Table 2 Summary of significant or reviewable power system incidents since the 2019 VAPR

Date	Incident	Consequence
16 November 2019	Victoria and South Australia system separation.	Over 500 MW of customer load reduction and 300 MW of generation reduction in Victoria and South Australia.
4 January 2020	Victoria and New South Wales system separation, New South Wales power system not in a secure operating state.	43 MW customer load reduction, and 34 MW generation reduction in New South Wales.
10 January 2020	Eildon to Mount Beauty 220 kV lines tripped simultaneously, auto reclosed, and tripped again.	No customer load reduction or generation reduction.
31 January 2020	Victoria and South Australia system separation.	450 MW customer load reduction in Victoria, and 640 MW generation reduction in South Australia.
2 March 2020[A]	Victoria and South Australia system separation.	No generation or customer load reduction.

A. This event does not technically meet the criteria of a reviewable event and is listed here for completeness. A circuit breaker at Heywood Terminal Station tripped as a credible contingency during a prior outage of the Mortlake to Moorabool No. 2 500 kV line.

16 November 2019

On 16 November 2019, the Heywood – Alcoa Portland (APD) – Mortlake and Heywood – APD – Tarrone 500 kV transmission lines were disconnected simultaneously, resulting in separation of South Australia and the majority of Victoria for almost five hours[31]. This event was the result of false signals received from telecommunications equipment that subsequently caused the maloperation of protection equipment on both circuits. During this event, supply to the APD aluminium smelter was disconnected for almost three hours, and AEMO instructed ElectraNet to reduce load at Olympic Dam to maintain system security.

4 January 2020

On 4 January 2020, a bushfire event in the Snowy Mountains area caused the Murray to Lower Tumut 330 kV line to trip followed by multiple transmission line outages in the area. This resulted in a separation event between Victoria and New South Wales[32]. Power system security in Victoria was maintained, however New

[28] For the full definition of "reviewable operating incident", see clause 4.8.15 of the NER.

[29] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

[30] 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.

[31] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2019/preliminary-incident-report---16-november-2019---sa---vic-separation.pdf.

[32] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en.

South Wales was insecure for two periods due to a risk of thermal overloading and a shortage of frequency control ancillary services (FCAS) in the New South Wales/Queensland island.

The outage of the 132 kV interconnection between Wagga and Yass resulted in the loss of approximately 43 MW of customer load in southern New South Wales, and activation of 68 MW of RERT.

10 January 2020

On 10 January 2020, the Eildon to Mount Beauty 220 kV lines tripped simultaneously, auto reclosed, and tripped again to lockout. Adverse weather conditions associated with bushfires have been deemed the most likely cause of the event, as no physical damage was identified.

31 January 2020

On 31 January 2020, a severe convective downburst near Cressy resulted in the collapse of several steel transmission towers carrying the Moorabool to Mortlake and Moorabool to Haunted Gully 500 kV lines. This in turn resulted in a separation event between South Australia and the majority of Victoria[33]. Of note about this incident:

- Following the incident, the Mortlake Power Station and APD aluminium smelter remained connected to the South Australian network, but were not connected to the rest of Victoria.
- Both APD potlines tripped, resulting in the loss of around 450 MW of load. Mortlake Power Station was used to restore supply to APD within several hours.
- A Lack of Reserve (LOR) 2 condition was declared in Victoria following the effective loss of Mortlake Power Station, several wind farms, and interconnection to South Australia. In response, AEMO dispatched 185 MW emergency reserves in Victoria, through use of RERT.
- South Australia and the network west of Moorabool remained separated from the NEM until 17 February, representing South Australia's longest period of islanded operation since market start.
- The Moorabool to Haunted Gully line was returned to service on 17 February 2020, and the Moorabool to Mortlake line was returned to service on 3 March 2020. Both lines were restored via temporary towers, and planning activities are well progressed for permanent replacement.

2.3 Supply-demand adequacy

The supply-demand balance remained tight in Victoria during 2019-20, with emergency reserves dispatched twice through RERT, in December 2019[34] and January 2020[35]. These events are summarised in Table 3.

These events were exacerbated by extreme weather conditions, physical asset damage, and multiple unplanned generator outages. On that basis, these events alone do not necessarily indicate a system normal need for substantial investment in new transmission assets.

Table 3 Summary of RERT activations in Victoria during 2019-20

Interconnector	RERT energy activated	Peak RERT dispatched	Duration of event	Total cost
30 December 2019	283 MWh	92 MW	6.5 hrs	$3.72 M
31 January 2020	697 MWh	185 MW	6 hrs	$7.71 M

[33] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-31-jan-2020.pdf.

[34] AEMO, *Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q4 2019*, February 2020, at https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2020/rert-quarterly-report-q4-2019.pdf?la=en.

[35] AEMO, *Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q1 2020*, May 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2020/rert-quarterly-report-q1-2020.pdf?la=en.

AEMO's latest *Electricity Statement of Opportunities* (ESOO)[36] forecasts that breaches of the reliability standard are unlikely for Victoria in the near term. However, increases to Victoria's import capabilities are required in the longer term, as further thermal plant retires in the Latrobe Valley around the end of the decade – and smaller investments may still show positive net benefits in the short term through improved resilience and operational flexibility.

In response, AEMO:

- Has executed an NMAS agreement with a generator proponent capable of increasing the voltage stability import limit if such action would avoid RERT or load shedding.
- Has progressed procurement activities at the request of the Victorian Government for a 250 MW SIPS on the existing VNI (Section 3.3.6).
- Is working with AusNet Services on several smaller upgrades on the VNI (Section 3.3.3).
- Is undertaking a RIT-T on a large new interconnector project between Victoria and New South Wales (Section 3.3.7).

2.4 Interconnector capability

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 and Table 5 provide an indication of trends in Victoria's exports to other regions across the interconnectors. Since the closure of Hazelwood Power Station in 2017, there has been a significant reduction in the quantity and time Victoria has spent exporting power to neighbouring regions.

This year, there has also been a significant change in exports to South Australia, where renewable investment and system strength constraints have promoted frequent flows into Victoria, while connection-related outages west of Moorabool reduced opportunities for high flows in both directions.

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

Interconnector	5-year average before Hazelwood closure	2017-18[A]	2018-19[A]	2019-20[A]
VNI	84%	49%	50%	56%
Heywood	82%	45%	42%	37%
Murraylink	46%	36%	50%	63%
Basslink	44%	55%	42%	44%
Victoria (net)	87%	51%	50%	50%

A. All data has been reported on a financial year basis (1 July to 30 June). This differs from previous VAPRs which were published in June and therefore reported on an April to March basis.

[36] AEMO, *2020 Electricity Statement of Opportunities*, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en.

[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, available on Statistical Reporting Streams page on the AEMO website, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams.

Table 5 Net energy exported from Victoria (GW)

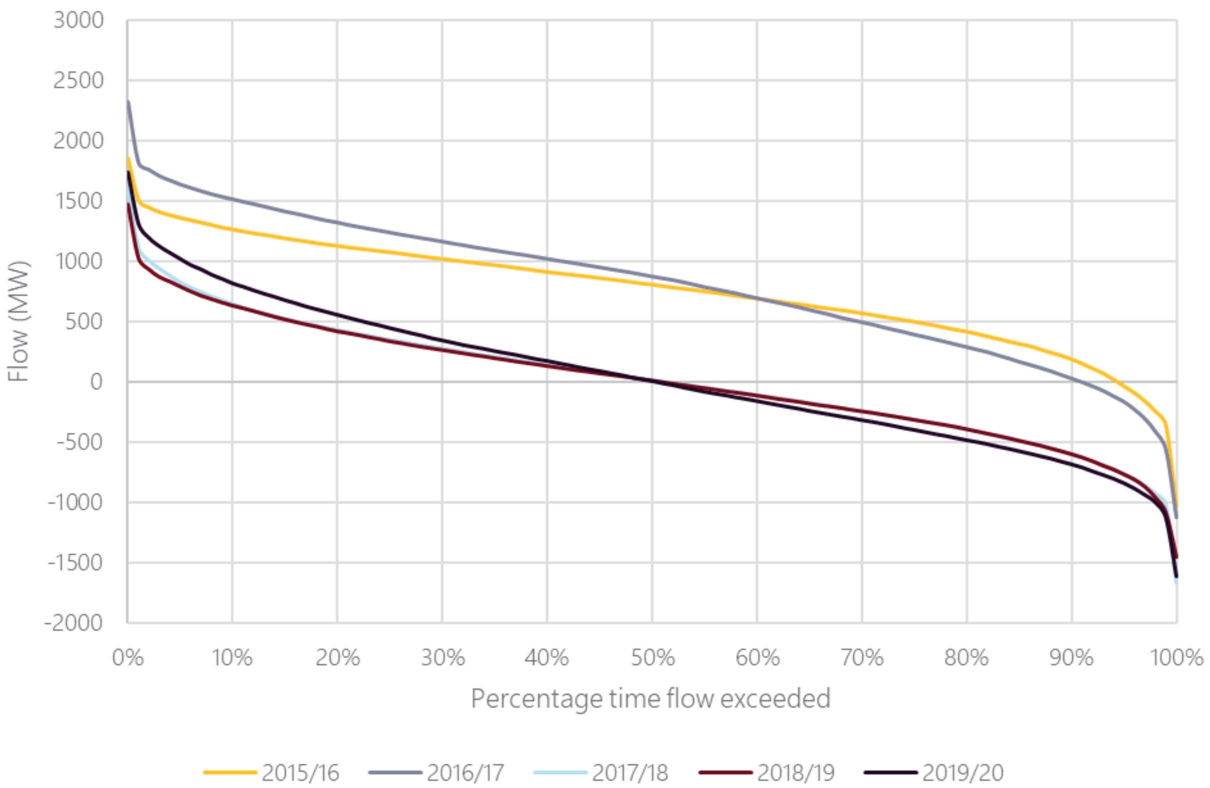
Interconnector	5-year average before Hazelwood closure	2017-18[A]	2018-19[A]	2019-20[A]
VNI	8,064	1,307	1,907	2,347
Heywood	3,648	-377	-777	-1,067
Murraylink	96	-226	-73	303
Basslink	-1,065	-392	-992	-1,025
Victoria (net)	10,743	312	65	559

A. All data has been reported on a financial year basis (1 July to 30 June). This differs from previous VAPRs which were published in June and therefore reported on an April to March basis.

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 black system event in 2016[39]. The maximum transfer currently allowed is 600 MW from Victoria to South Australia, and 550 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.

Figure 11 presents the Victorian net export duration curves for the past five years. This shows the step change in exports following closure of the Hazelwood Power Station in 2017. AEMO expects that exports will increase again over time as new renewable generation is connected to meet the VRET, and as new network projects are deployed to reduce constraints and facilitate the transfer of this renewable energy. These exports are expected to grow steadily until the retirement of further thermal power stations in the Latrobe Valley.

Figure 11 Victoria net export duration curve (all interconnectors)



[39] AEMO, *Black System in South Australia, 28 September 2016*, March 2017, listed under 2016 reports at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

2.5 Operational challenges

Strong investor interest in western parts of Victoria is continuing to shift the geographic diversity of supply sources away from the Latrobe Valley, and the increasing penetration of non-synchronous generation in more remote areas is changing the technical characteristics of the system. Overlaid on this, consumer response through investment in distributed energy resources (DER) is also changing the patterns of network flow across the state.

Over time, these changes will drive matching network investment projects that capitalise on their benefits while mitigating the operational risks they present. However, the pace of change means that some transitionary issues are already presenting challenges to the real-time operation of the network, requiring interim measures and increasing levels of operating action to balance system security and reliability.

This section discusses how network operation has been impacted over the past year by the changing technical characteristics and geography of supply, particularly where this has reduced system resilience, resulted in additional network constraints, or otherwise increased operational complexity.

2.5.1 West Murray considerations

Voltage oscillations under system normal

Over the last two years, a considerable volume of new inverter-based generation has connected in the West Murray Zone. This area, which spans north-west Victoria and south-west New South Wales, is both weakly interconnected and electrically remote from synchronous generation sources that would normally provide critical system strength services.

In September 2019, AEMO identified that five solar farms in the West Murray Zone could exhibit voltage oscillations following transmission line faults, that exceeded the regulated limits for power system security.

In response, AEMO invoked a set of system normal network constraints to restrict the output and number of online inverters in order to manage system security and maintain post-fault stability[40].

In parallel, AEMO worked closely with the impacted participants, their equipment suppliers, and NSPs to identify and implement acceptable remediation through inverter tuning activities. The testing completed in April 2020, and the associated constraints were subsequently lifted.

Voltage oscillations under prior outage conditions

In February 2019, AEMO conducted studies which showed that during a planned outage in the West Murray Zone, a subsequent contingency event could cause undamped voltage oscillations. These oscillations have the potential to cause further disruption or voltage collapse[41].

To maintain power system security during these prior outage conditions, new network outage constraints were developed and applied to reduce the output of local generating units during specific outages.

Over the past two years, a number of such planned outages were required to support new connections and commissioning processes. This resulted in high binding hours for this group of constraints during the 2018-19 and 2019-20 financial years, as indicated in Section 2.6.

These constraints are not expected to bind as frequently in future years, with fewer new connection projects committed to proceed on the associated lines. See Section 3.1.3 for further information on committed and potential generation projects.

[40] AEMO, *Notice of Victorian Fault Level shortfall at Red Cliffs*, December 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice_of_Victorian_Fault_Level_Shortfall_at_Red_Cliffs.pdf.

[41] AEMO, *Planned Outages in the North Western Victoria & South West New South Wales Transmission Network*, 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.

System strength shortfall

System strength is the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance[42].

In December 2019, AEMO published a notice of fault level shortfall at Red Cliffs Terminal Station. The fault level shortfall, also referred to as a system strength gap, was declared with immediate effect and with a magnitude of 312 MVA[43].

As the System Strength Service Provider for Victoria, AEMO is progressing remediation of this gap in two stages – an immediate solution using existing providers, and a long-term solution with a broader scope to include potential network and non-network options. Section 3.3.4 provides further information.

2.5.2 Minimum demand considerations

Voltage management

Under minimum demand conditions, and without operator intervention, high voltages can occur on the Victorian transmission network. Short-term operational measures, such de-energising transmission lines, have become necessary during these periods to maintain secure voltages. Projected reductions in minimum demand over the next decade, linked with rapid uptake in DER, will act to further exacerbate this issue.

In 2019, AEMO entered into an NMAS agreement with a generation proponent who was capable of providing additional reactive capabilities on request. AEMO has used this contract operationally, while separately progressing a long-term solution through a formal RIT-T processes (see Section 3.3.2).

The frequency and severity of voltage control interventions is increasing, and reliance on such measures results in higher market costs, reduced system resilience, and higher system security risks. Table 6 summarises the frequency with which these measures have been used for voltage control over the past two years.

In 2019-20, operator interventions were required 128 times to manage high voltages on the network during light load conditions, particularly around the Keilor Terminal Station. These actions included de-energising a single 500 kV line 72 times, activating NMAS on 51 of these occasions and progressing to deenergise a second 500 kV asset four times. A voltage control direction was also issued in March 2020.

Table 6 Historical frequency of operational measures to manage high voltages

Operational measure	Number of times action was taken							
	Q3 2018	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020
De-energise first 500 kV line	10	30	0	25	14	28	15	15
Activate NMAS[A]	N/A	N/A	2	9	0	17	20	14
De-energise second 500 kV line	1	5	0	1	0	3	0	1
De-energise third 500 kV line	0	1	0	0	0	0	0	0
Issue directions	0	4	0	0	0	0	1	0
Total actions	**11**	**40**	**2**	**35**	**14**	**48**	**36**	**30**

A. In March 2019, AEMO entered a short-term NMAS agreement for voltage control support at times of minimum demand.

[42] See AEMO, *System strength explained*, March 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf?la=en.

[43] While the shortfall is described in terms of a fault level contribution, other factors must also be considered when resolving system strength issues. In particular, the geography, electrical proximity, technology performance, and interaction between devices must all be included.

The NMAS contract has provided a valuable interim tool for voltage management while long-term reactive assets are delivered. However, in mid-2020, a number of generating units declared concurrent planned outages for October 2020, placing significant restrictions on the reactive support available to the system.

AEMO worked closely with these participants to reschedule outages where possible, however many had been deferred from earlier in the year due to COVID-19 considerations. AEMO and AusNet Services have now deployed an over-voltage protection scheme for the Keilor Terminal Station that will provide an effective, achievable, and cost-effective solution for the critical period in October 2020.

Minimum synchronous units to maintain system strength

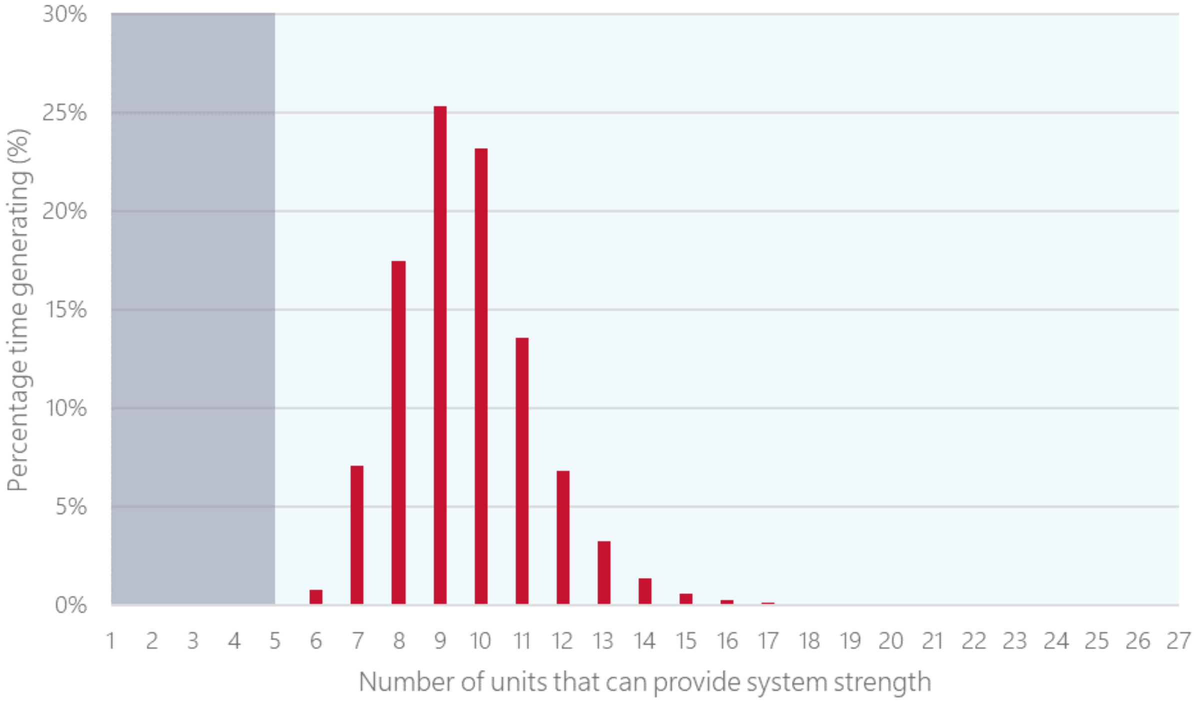
A minimum level of system strength is required for the power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance. To maintain system strength in Victoria, specific combinations of synchronous units must always remain online[44].

These unit combinations have an aggregate minimum generation requirement of between 800 MW and 1,200 MW, representing the threshold below which Victoria must export to neighbouring regions to maintain enough local sources of system strength. Victoria is well connected with its neighbouring regions, and minimum demand is not expected to cross this threshold until at least 2025[45]. However, the system strength combinations can also bind operationally during periods with multiple concurrent generator outages.

Figure 12 shows the frequency of units online over the last 12 months for generators contained in at least one viable Victorian system strength combination. In general, valid combinations require the equivalent of five large thermal units online (with lower levels possible when compensated by several peaking units).

As minimum demands fall in future years, this curve is expected to shift further to the left, increasing the risk of system strength interventions to maintain enough synchronous units online. Future network investment may be required to remediate this issue, and AEMO monitors these needs through an annual outlook of system strength issues across all regions. The next update is expected in December 2020.

Figure 12 Available system strength units during 2019-20 (excluding Bogong and Murray 2)



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[44] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

[45] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en.

2.5.3 Reverse power flows

The increasing volume and geographic distribution of generators connecting at the sub-transmission and distribution level is causing some terminal stations (that have historically behaved as net loads) to increasingly act as net generation sources to the transmission network. Section 3.1 provides more detail on new generator connections that have occurred since the 2019 VAPR was published.

The frequency and magnitude of these 'reverse power flows' continues to increase in Victoria, with seven terminal stations experiencing such flows in 2019-20. This is up from five terminal stations reported in the 2019 VAPR, and with increased durations observed across most stations.

The Horsham 220/66 kV transformers are an exception to this trend, in that they experienced significantly fewer reverse flows compared with 2018-19. The output from connected generation remained consistent over the period, however changes in consumption patterns and increased local energy consumption have contributed to relatively few periods with a net surplus.

Table 7 outlines the number of hours that reverse flows occurred at these seven terminal stations over the last three years, and notes the associated new distribution connected projects at each location[46].

These statistics confirm the impact that changes in the distribution and sub-transmission network are having at a transmission level, and AEMO has recently completed a review of existing control schemes in Victoria to ensure they remain fit-for-purpose as flow patterns change (see Section 4.7).

Injections into the transmission network are expected to grow over time, particularly as further generation projects connect and DER offsets local demand to create periods of surplus supply in the distribution network. This will present new operational and network planning challenges to both TNSPs and distribution network services providers (DNSPs).

Section 6.4 presents more information on the emerging challenges presented by reverse power flows.

Table 7 Reverse flow statistics at identified locations

Transformer location	Hours with reversed flows (2019-20)	Hours with reversed flows (2018-19)	Hours with reversed flows (2017-18)	Notes
Wemen 220/66 kV	3,241 hrs	1,926 hrs	0 hrs	Follows connection of Bannerton Solar Park in March 2019.
Terang 220/66 kV	2,905 hrs	2,288 hrs	153 hrs	Follows connection of Salt Creek Wind Farm in July 2018.
Kerang 220/66/22 kV	2,646 hrs	2,504 hrs	137 hrs	Follows connection of Gannawarra Solar Farm in October 2018.
Horsham 220/66 kV	827 hrs	1,358 hrs	769 hrs	Follows connection of Kiata Wind Farm in January 2018.
Red Cliffs 220/66/22 kV	477 hrs	536 hrs	0 hrs	Follows connection of Karadoc Solar Farm in November 2018.
Shepparton 220/66 kV	940 hrs	0 hrs	0 hrs	Follows connection of Numurkah Solar Farm in September 2019.
Ballarat 220/66 kV	838 hrs	0 hrs	0 hrs	Follows connection of Yendon Wind Farm, currently in commissioning.

[46] These values differ from those in the 2019 VAPR due to a shift to financial year reporting. The 2019 VAPR considered 1 April to 31 March.

2.6 Impact of Victorian transmission constraints

This section summarises the Victorian transmission network constraints that resulted in the highest dispatch impact during the 2019-20 financial year. Comparison values are also shown for the 2018-19 financial year.

The ranking of each constraint (or group of constraints) is determined by the calculated 'binding impact' of the constraints. The binding impact of a constraint is derived by combining the marginal value for each dispatch interval over the period considered. It is used to distinguish between the severity of different binding constraint equations and represents the relative financial impact associated with that constraint equation. However, it does not represent the market benefit from investment to remove the constraint in absolute terms.

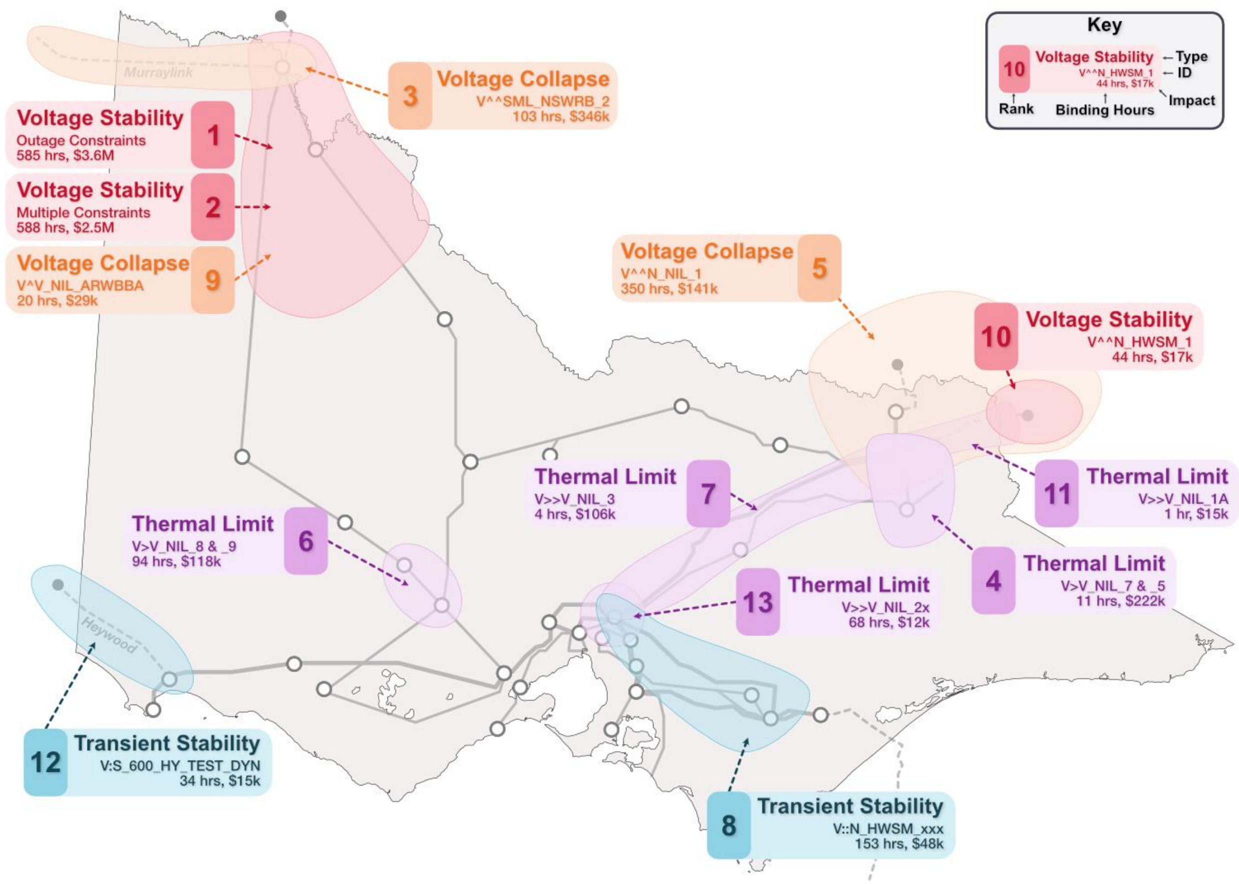
Figure 13 summarises these constraints by type and location around the Victorian system.

While the constraints summarised in this section are those with the most significant impact historically, investment to remove any specific constraint would also require consideration of limitations that may bind below these limits and reduce the benefits unless those constraints are also alleviated.

For example, investment to remove Constraint 11 in Figure 13 would not result in unconstrained flows along the VNI, as this constraint competes for dominance against Constraint 5 and Constraint 10. In other parts of the state, constraints that currently do not bind at all may begin to bind as other limits are removed.

To assess the true benefits of relieving constraints, AEMO undertakes detailed power system and economic modelling through prefeasibility and RIT-T processes (see Chapter 4).

Figure 13 Map of most significant Victorian transmission constraints in 2019-20



- Constraint impact is measured as the sum of marginal values for a constraint, and provides indicative impacts on dispatch outcomes. This is a guide, but does not reflect the financial impacts on individual generators, or the market benefits available under a RIT-T.
- Constraint rankings are based on a combination of constraint impact and binding hours.
- The top ranked constraint represents a collection of prior outage limitations, that applied during a set of planned network outages required to facilitate new connections in the north-west of Victoria.

North West Victoria and Murray River

The transmission network in the north-west of Victoria and in the Murray River region has been characterised by significant new renewable generation investment, and accompanying outages to facilitate commissioning of these projects. This is a relatively remote part of the network, subject to voltage stability and voltage collapse constraints that have limited flows and generation over the last 12 months. Table 8 presents further information on these limitations.

Table 8 Equations with significant binding durations or impact – North West Victoria

Rank	Equation ID	Binding hours		Binding impact		Description
		2018-19	2019-20	2018-19	2019-20	
1	North-west Vic voltage oscillation (prior outage)	591[A]	585[A]	$2,572k[A]	$3,583k[A]	This represents a set of the network constraint equations associated with voltage oscillation during a range of prior outage conditions.
2	North-west Vic voltage oscillation (system normal)	-	588[A]	-	$2,489k[A]	This represents a temporary set of the network constraints associated with voltage oscillation during system normal in north-west Victoria.
3	Red Cliffs voltage stability V^^SML_NSWRB_2[B]	38	103	$95k	$346k	To avoid voltage collapse at Red Cliffs for the loss of Darlington Point to Balranald (X5) or Balranald to Buronga (X3) 220 kV lines when the New South Wales Murraylink runback scheme is unavailable.
9	North-west Vic voltage stability V^V_NIL_ARWBBA[C]	-	20	-	$29k	To limit north-west Victorian generation to 600 MW to avoid voltage collapse on trip of Ararat to Waubra to Ballarat 220 kV line.

A. This is the sum of the binding hours and binding impacts for multiple constraint equations during prior outage and system normal conditions (37 and 9 respectively). These values may be overestimated due to constraints binding concurrently.
B. The V^^SML_NSWRB_2 constraint replaced V^SML_NSWRB_2 in October 2019.
C. The N^^V_NIL_ARWBBA constraint replaced V^V_NIL_ARWBBA in May 2020.

South West corridor and the Heywood Interconnector

In 2019-20, there were two primary types of constraint active in the South West corridor:

- Thermal limitations on the Ballarat to Waubra 220 kV line due to the connection of additional renewable generation in the West Murray Zone. AEMO is investigating the possibility of installing a post-contingent generation tripping scheme to address this (see Section 4.2).
- A transient stability limitation that restricts exports from Victoria to South Australia. This constraint represents a 600 MW limit to ensure oscillatory stability, and has been applied as part of the test program to further release Heywood Interconnector capacity.

Table 9 provides further details on each of these limitations.

Table 9 Equations with significant binding durations or impact – South West corridor

Rank	Equation ID	Binding hours		Binding impact		Description
		2018-19	2019-20	2018-19	2019-20	
6	BATS–WBTS thermal V>V_NIL_8 & V>>V_NIL_9	-	94	-	$118,056	To avoid overloading the Waubra to Ballarat 220kV line on trip of Kiamal to Red Cliffs 220 kV line or Kerang to Bendigo 220 kV line.
12	Vic to SA transient stability V:S_600_HY_TEST_DYN	21	34	$7,668	$14,664	600 MW limit on Victoria to South Australia transfer on Heywood with dynamic headroom.

Eastern Victoria and the VNI

Constraints in the east of Victoria are primarily dominated by limitations across the VNI. There are several thermal constraints limiting flows between South Morang and Murray, while voltage collapse and voltage stability limitations in the border region. AEMO is addressing these constraints in three ways:

- **Thermal exports** – AEMO and TransGrid jointly completed a RIT-T in 2020 to upgrade interconnector capacity from Victoria into New South Wales (see Section 3.3.3).
- **Thermal imports** – AEMO, at the request of the Victorian Government, has progressed procurement of a SIPS that would increase interconnector capacity from New South Wales into Victoria (Section 3.3.6).
- **Voltage limits** – in 2019, AEMO entered into a new NMAS arrangement to relieve voltage stability limitations at times of high demand in Victoria where these services may avoid the need for load shedding or dispatch of emergency reserves (Section 3.3.2).

In the south east, transient stability constraints have bound more frequently this year, related to outages on the Hazelwood – South Morang and Hazelwood – Rowville 500 kV lines. The frequency of these outages has increased due to high voltages at low demand. Section 3.3.2 discusses AEMOs voltage control investments.

Table 10 provides further details on each of the above limitations.

Table 10 Equations with significant binding durations or impact – Eastern Victoria

Rank	Equation ID	Binding hours		Binding impact		Description
		2018-19	2019-20	2018-19	2019-20	
4	MBTS – DDTS 220kV line thermal constraint V>V_NIL_7 & V>>V_NIL_5	17	11	$198,238	$222,170	To prevent overload of either Mount Beauty to Dederang 220 kV line (flow North) for trip of the parallel line or Eildon to Thomastown 220 kV line.
5	Voltage instability (high export, light demand, system normal) V^^N_NIL_1	126	350	$94,529	$141,368	To avoid voltage collapse in Northern Victoria and Southern New South Wales for loss of APD potlines following fault on one of the 500 kV lines in South West Victoria (light load, high export to New South Wales).
7	DDTS – SMTS thermal V>>V_NIL_3	5	4	$762,280	$105,538	To avoid overloading a Dederang to South Morang 330 kV line (flow South) for parallel trip.
8	Vic transient instability V::N_HWSM_xxx	22	153	$5,704	$48,384	For an outage of the Hazelwood to South Morang or Hazelwood to Rowville 500 kV line, to prevent transient instability for a trip of a Hazelwood to South Morang 500 kV line.
10	Voltage instability (high Vic export and light Vic demand, prior outage) V^^N_HWSM_1	-	44	-	$16,847	To avoid voltage collapse around Murray for loss of all APD potlines for an outage of the Hazelwood to South Morang 500 kV line.
11	Murray – DDTS thermal V>>V_NIL_1A	1	<1	$81,414	$14,700	To avoid overloading the Murray to Dederang No. 1 330 kV line (flow from Murray to Dederang) for loss of the parallel No. 2 line when the DBUSS-Line control scheme is enabled.
13	SMTS F2 thermal constraint V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	124	68	$36,499	$11,830	To avoid overloading the South Morang F2 transformer when Yallourn Unit 1 is in 220 kV mode and Hazelwood is operating in radial mode.

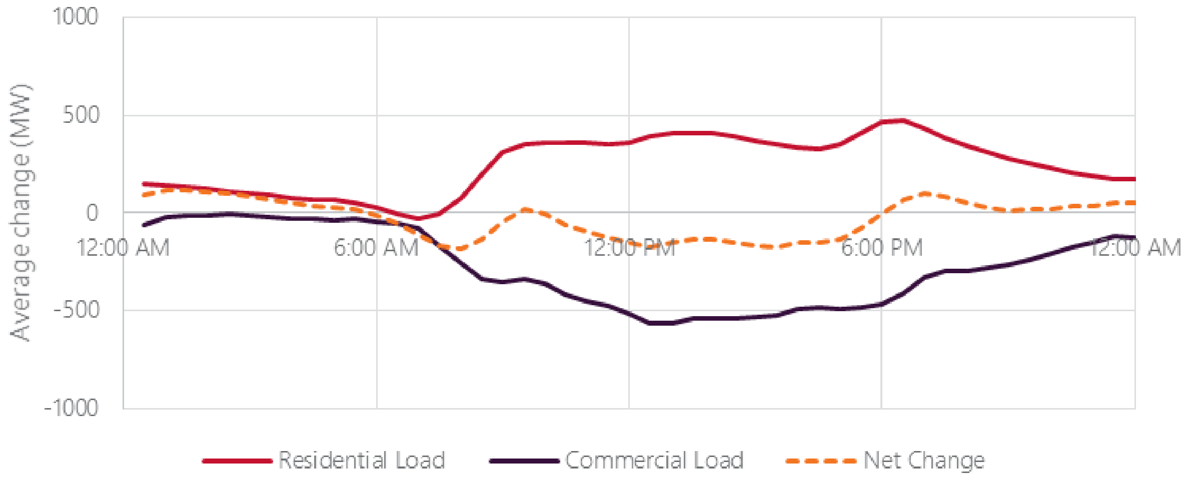
2.7 Impact of COVID-19

From mid-March 2020, nationwide restrictions and drastic lifestyle changes were put into effect in response to the COVID-19 pandemic. These restrictions have escalated and changed over subsequent months, and have limited commercial business activity while driving rapid changes in electricity consumption patterns.

On a sector basis, COVID-19 initially resulted in an approximately 500 MW shift between commercial and residential demand, although net daily demands remained relatively consistent with previous years. In Victoria, stage 4 restrictions came into effect on 5 August 2020 requiring many businesses to close, resulting in significantly reduced commercial demand which more than offset increased residential demand. Time-of-day usage patterns have reduced the morning peak, with upward pressure into the afternoon peak.

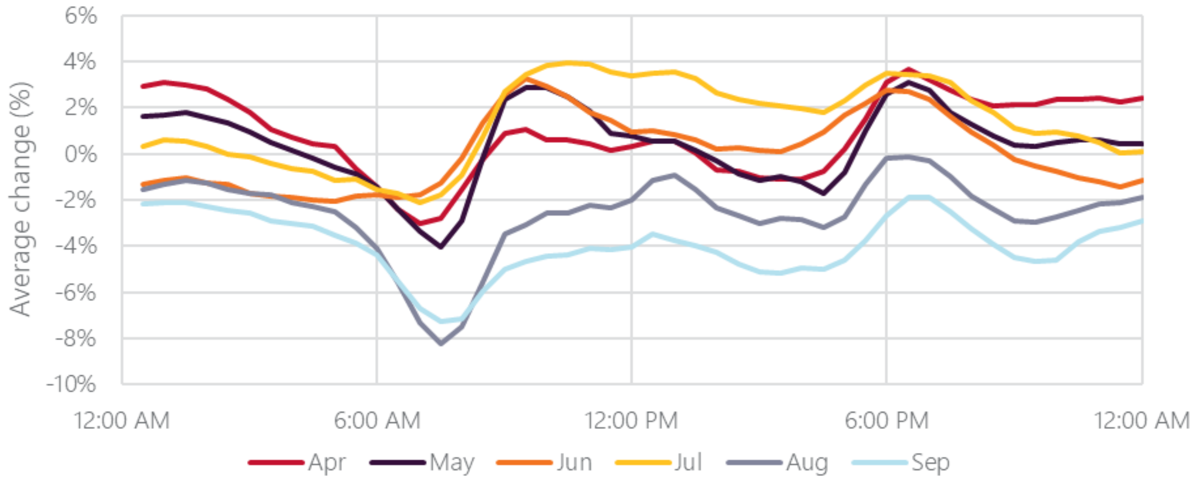
Figure 14 and Figure 15 show the change in weekday demand by sector[47] and by time-of-day[48] respectively.

Figure 14 COVID-19 impact on sector demand



Change in Victorian-average weekday demand by sector and time-of-day (1 April to 17 May 2020 versus 1 April to 17 May 2019).

Figure 15 COVID-19 impact on time-of-day operational demand



Change in Victorian-average underlying demand by time-of-day (2020 versus 2019).

[47] AEMO estimated residential load using household meter data, and estimated commercial load using the difference residential and total distribution load.

[48] AEMO has developed models that unbundle the impact of COVID-19 from other factors, and used this to project demand absent the pandemic.

Changes in the geography of demand

Figure 16 presents the change in total electricity consumption by Victorian region between May 2020 and May 2019, while Figure 17 presents this same change for residential consumption alone. These show a trend of diversification towards regional parts of the state, and a substantial shift towards residential demand.

Figure 16 COVID-19 total changes in consumption, July 2020 vs July 2019 (AusNet Services)

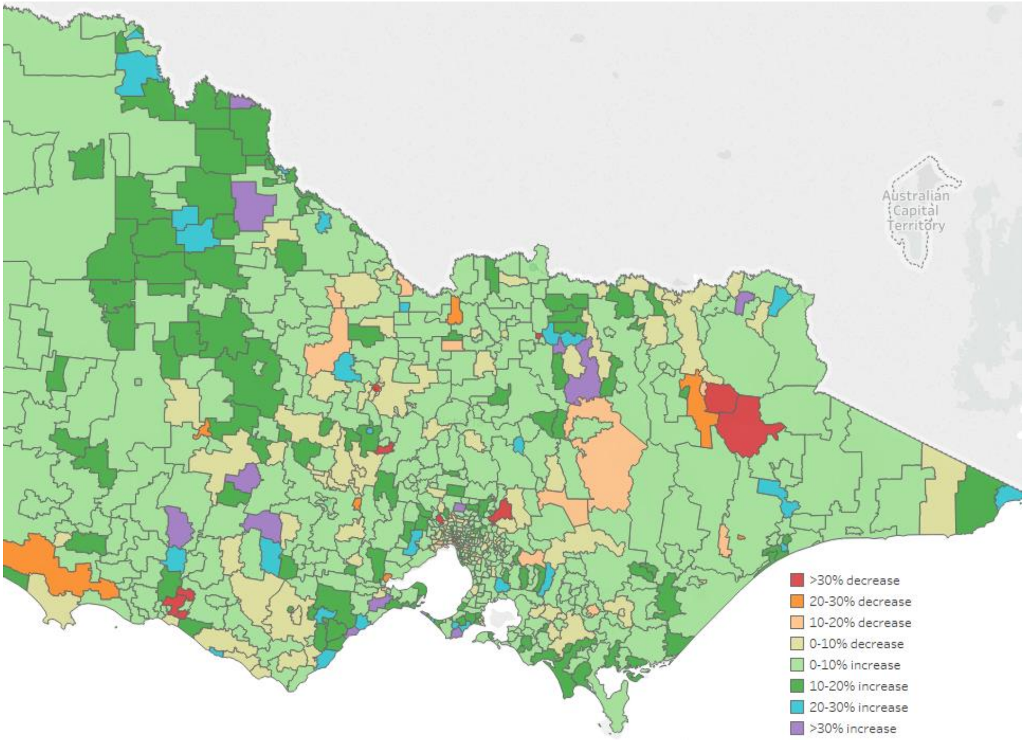
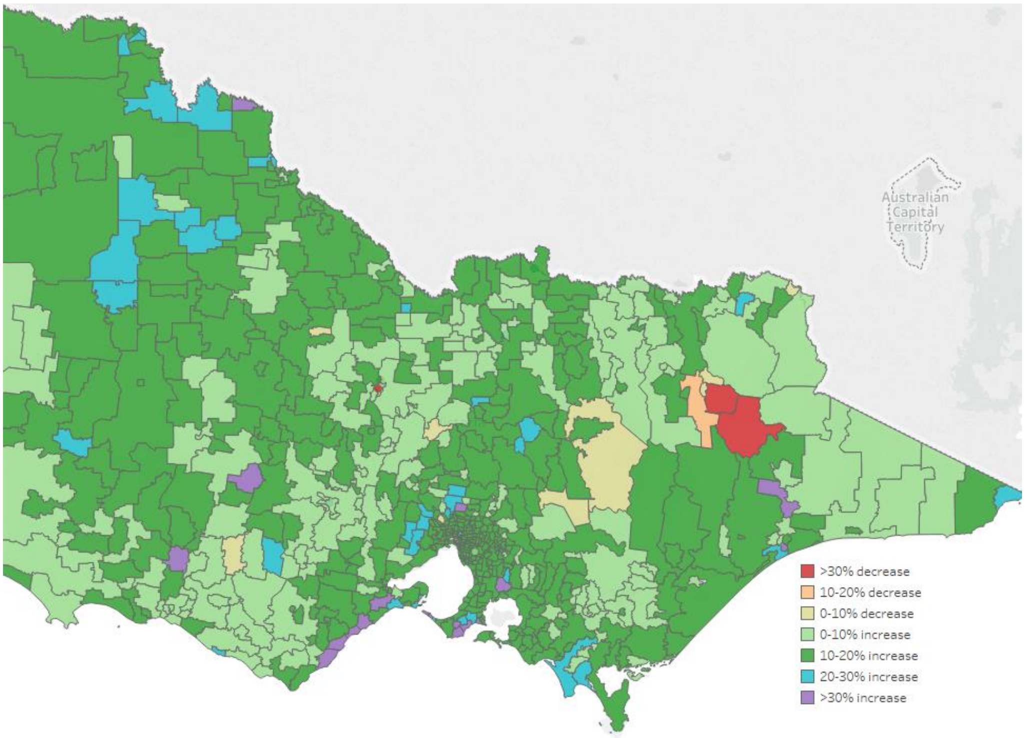


Figure 17 COVID-19 residential changes in consumption, July 2020 vs July 2019 (AusNet Services)



2.8 Network performance at times of high network stress

AEMO reviewed the loading of DSN network elements to assess levels of network stress since the 2019 VAPR.

To understand how the network performed at times of high stress, AEMO used four operational 'snapshots'[49] of the power system to capture network conditions[50] during periods of maximum demand, minimum demand, high local wind generation, and high exports to New South Wales[51].

This discussion is complemented by additional information provided in the historical DSN rating and loading workbook[52]. While the Victorian daily minimum demand has historically occurred overnight, it was reported during the afternoon for the first time in the 2019 VAPR, and this occurred again in the 2020 VAPR analysis.

Table 11 Summary of operating conditions

	Maximum demand snapshot	Minimum demand snapshot	High export from Victoria snapshot	High Wind snapshot
Date and time[A]	31 January 2020 17:02:24	01 January 2020 12:31:28	15 June 2020 22:01:04	13 June 2020 18:32:00
Temperature in Melbourne	41.8 °C	22.5 °C	12.5 °C	13.7 °C
Victorian operational demand at time of snapshot[B]	9,667 MW	3,300 MW	5,544 MW	6,315 MW
Victorian generation at time of snapshot	8,655 MW	4,478 MW	6,288 MW	7,233 MW
Net power flow into Victoria via interconnection	866 MW	-1,268 MW	-989 MW	-1,044 MW
Distributed PV	410 MW	1,432 MW	0 MW	0 MW
Renewable generation in Victoria	2,403 MW	638 MW	1,926 MW	2,857 MW
Battery storage	0 MW	1 MW	1 MW	0 MW
RERT dispatched	185 MW (VIC)	0 MW	0 MW	0 MW
System security	Network reconfiguration and directions for system strength	Line de-energised for voltage, NMAS utilised for voltage control	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. It is equal to actual generation for all semi-scheduled and non-scheduled generators.

[49] These snapshots include DSN outages, and estimates of some system parameters based on measurements in AEMO's Energy Management System (EMS).

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

[51] A high export period is classified as a snapshot with high flow through the South Morang F2 500/330 kV transformer.

[52] For the maximum demand snapshot ratings and loadings, see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

2.8.1 Maximum demand snapshot

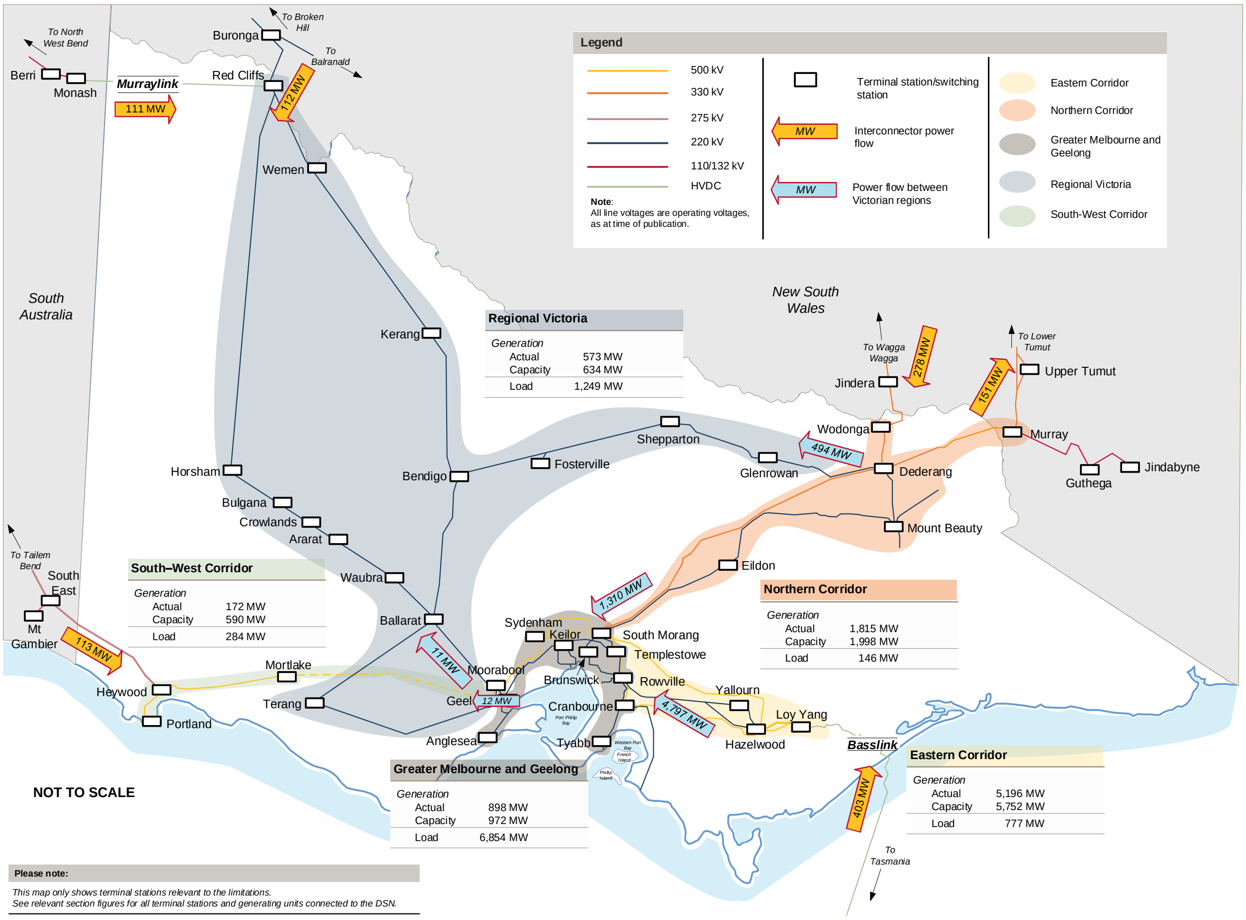
The maximum demand snapshot captures conditions when many network elements experience their maximum loading for the year. Table 12 and Figure 18 show the prevailing conditions at the time of maximum operational demand in Victoria (5:02 pm on 31 January 2020).

Table 12 Maximum demand snapshot – summary of operating conditions

Characteristic	Value	Notes
Victorian operational demand[A]	9,667 MW	The maximum operational demand was between the 50% probability of exceedance (POE) maximum demand forecast of 9,253 MW, and the 10% POE maximum demand forecast of 10,397 MW.
Sum of Victorian loads	9,310 MW	74% (6,854 MW) was concentrated in Greater Melbourne and Geelong.
Sum of Victorian generation	8,655 MW	50% of Victorian generation originated from the Eastern Corridor.
Sum of Victorian available generation capacity	9,945 MW	
Net power flow into Victoria via interconnection	866 MW	• +239 MW on the VNI (New South Wales). • +113 MW on the Heywood Interconnector (South Australia). • +111 MW on the Murraylink Interconnector (South Australia). • +403 MW on the Basslink Interconnector (Tasmania).
Distributed PV	410 MW	Serving 4.2% of end user demand.
Battery storage	0 MW	
Victorian renewable generation	2,403 MW	Representing 27.8% of total Victorian generation, and comprising: • 74 MW of non-scheduled wind. • 462 MW of dispatched wind. • 52 MW of dispatched solar. • 1,815 MW of hydroelectric generation.
RERT dispatched	185 MW	The loss of imports from South Australia, coupled with high temperatures, resulted in an LOR 2 condition and subsequent dispatch of this RERT in Victoria. 134 MW of RERT was also dispatched in New South Wales.
Other system security considerations	Part of the Victorian network (Heywood, Portland, Mortlake) was separated from the rest of Victoria due to loss of both 500 kV lines between Moorabool to Mortlake and Moorabool to Haunted Gully. This section of the Victorian network was reconfigured and connected to the South Australian network via Heywood. Import on the Heywood interconnector listed above was supplying only this localised part of the Victorian network.	

A. Operational demand is the sum of all Victorian loads and network losses.

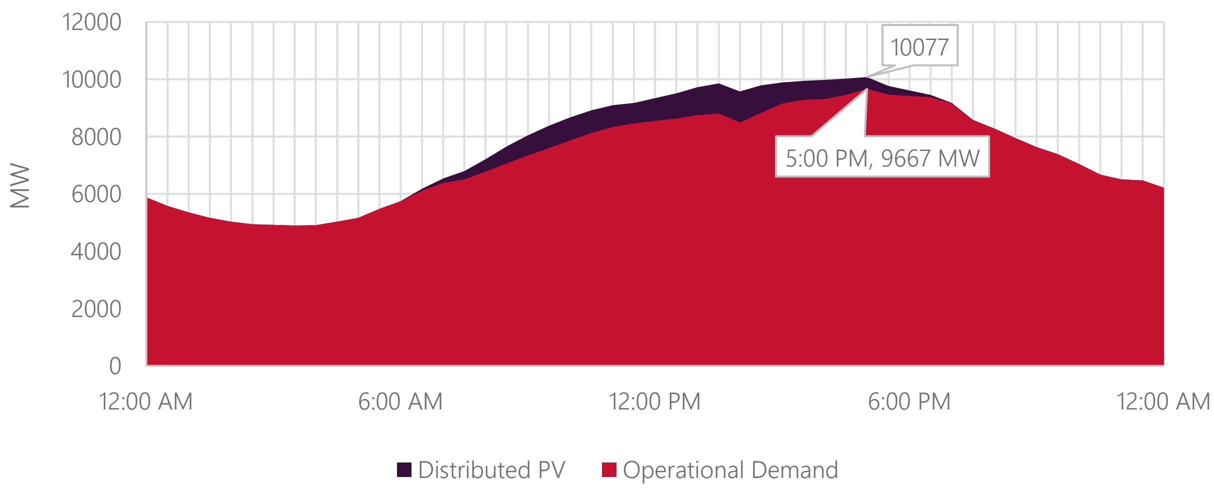
Figure 18 Maximum demand snapshot – generation, load, and interconnector flow



Distributed PV impacts on maximum demand

At the time of maximum demand in, distributed PV had an aggregate output of over 400 MW, as illustrated in Figure 19. While solar contribution to peak is typically helpful, it can also increase the risks associated with ramping and credible contingencies (where weather patterns or sympathetic tripping could cause rapid changes in the location and size of effective demand to be met by the transmission network). Section 4.5.5 and Section 6.4.3 provide more information on these types of emerging challenges.

Figure 19 Victorian demand profile of maximum demand day (31 January 2020)



2.8.2 Minimum demand snapshot

The minimum demand snapshot captures conditions under which voltages control may prove challenging, and is most likely to exceed operating limits. Table 13 and Figure 20 show the prevailing conditions at the time of minimum demand in Victoria (12:31 pm on 1 January 2020)[53].

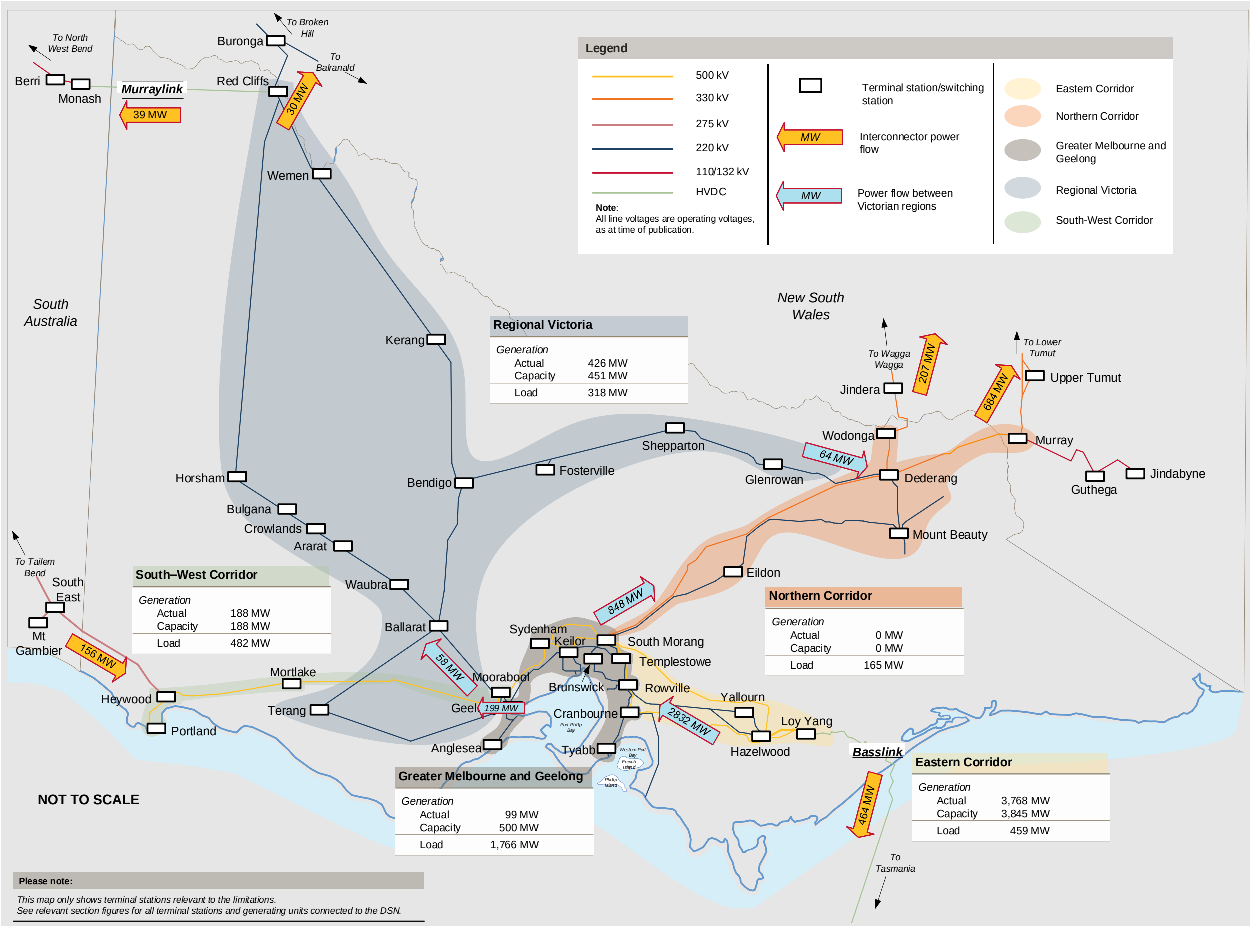
Table 13 Minimum demand snapshot – summary of operating conditions

Characteristic	Value	Notes
Victorian operational demand[A]	3,300 MW	Minimum demand was between the 50% POE minimum demand forecast of 3,383 MW and the 90% POE minimum demand forecast of 3,176 MW. This snapshot reflects a new record for minimum daytime demand for Victoria. Previously, the all-time record minimum demand for Victoria had been 3,217 MW and occurred at 6:02 am on 12 November 2017. This previous record occurred during an unplanned outage at APD where approximately 380 MW of potline load was offline.
Sum of Victorian loads	3,190 MW	55% (1,766 MW) was concentrated in Greater Melbourne and Geelong.
Sum of Victorian generation	4,478 MW	84% of Victorian generation originated from the Eastern Corridor.
Sum of Victorian available generation capacity	4,984 MW	
Net power flow into Victoria via interconnection	-1268MW	• -921 MW on the VNI (New South Wales). • +156 MW on the Heywood Interconnector (South Australia). • -39 MW on the Murraylink Interconnector (South Australia). • -464 MW on the Basslink Interconnector (Tasmania).
Distributed PV	1,432 MW	Serving 31.0% of end user demand.
Battery storage	1 MW	
Victorian renewable generation	638 MW	Representing 14.3% of total Victorian generation, and comprising: • 128 MW of non-scheduled wind. • 254 MW of dispatched wind. • 256 MW of dispatched solar. • 0 MW of hydroelectric generation.
RERT dispatched	0 MW	
Other system security considerations	Operational measures were applied to maintain voltages within limits, including the de-energisation of a 500 kV line, and activation of an NMAS contract to source additional reactive power from a generating unit. See Section 2.5.2 for details about historical use of operational measures to manage high voltage, and Section 3.3.2 provides more detail on AEMO's further investment activities to manage high voltage during low demand periods.	

A. Operational demand is the sum of all Victorian loads and network losses.

[53] A new minimum demand of 3,063 MW was achieved on 11 October at 2:00 pm, however this is outside the 2020 VAPR study period, and will be reported on in the 2021 VAPR.

Figure 20 Minimum demand snapshot – generation, load, and interconnector flow

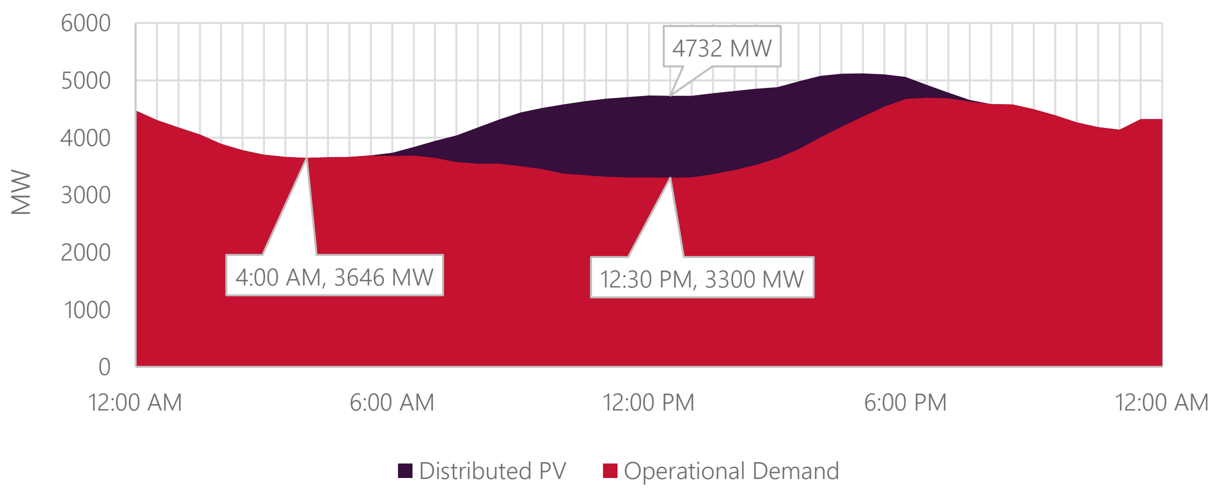


Distributed PV impacts on minimum demand

Distributed 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 smoothing the morning and late afternoon peaks. Distributed PV penetration in Victoria increased by more than 630 MW between April 2019 and June 2020.

Figure 21 presents the impact of distributed PV generation on the day of annual minimum demand in 2020. At the time of minimum demand, distributed PV had an aggregate output of over 1,400 MW.

Figure 21 Victorian demand profile of minimum demand day (1 January 2020)



The increasing penetration of distributed PV resulted in a shift of Victorian minimum demand from overnight to the early afternoon. Since the 2019 VAPR, daily minimum demand occurred between 10:00 am and 3:00 pm on 51 separate occasions. During each of these, distributed PV had an aggregate output of at least 680 MW. In comparison, there were only 12 similar occasions reported in the previous VAPR.

2.8.3 High wind snapshot

The high wind snapshot captures conditions where Victoria experiences high output from scheduled wind generating units. Table 14 and Figure 22 show the prevailing conditions at the time of high wind generation output in Victoria (6:32 pm on 13 June 2020).

While thermal limitations and high voltage issues were not identified in the snapshot assessment, operational challenges are emerging rapidly in association with large-volumes of inverter-based generation connecting in weaker parts of the transmission network. Section 2.5.2 provides more information on these emerging operational issues.

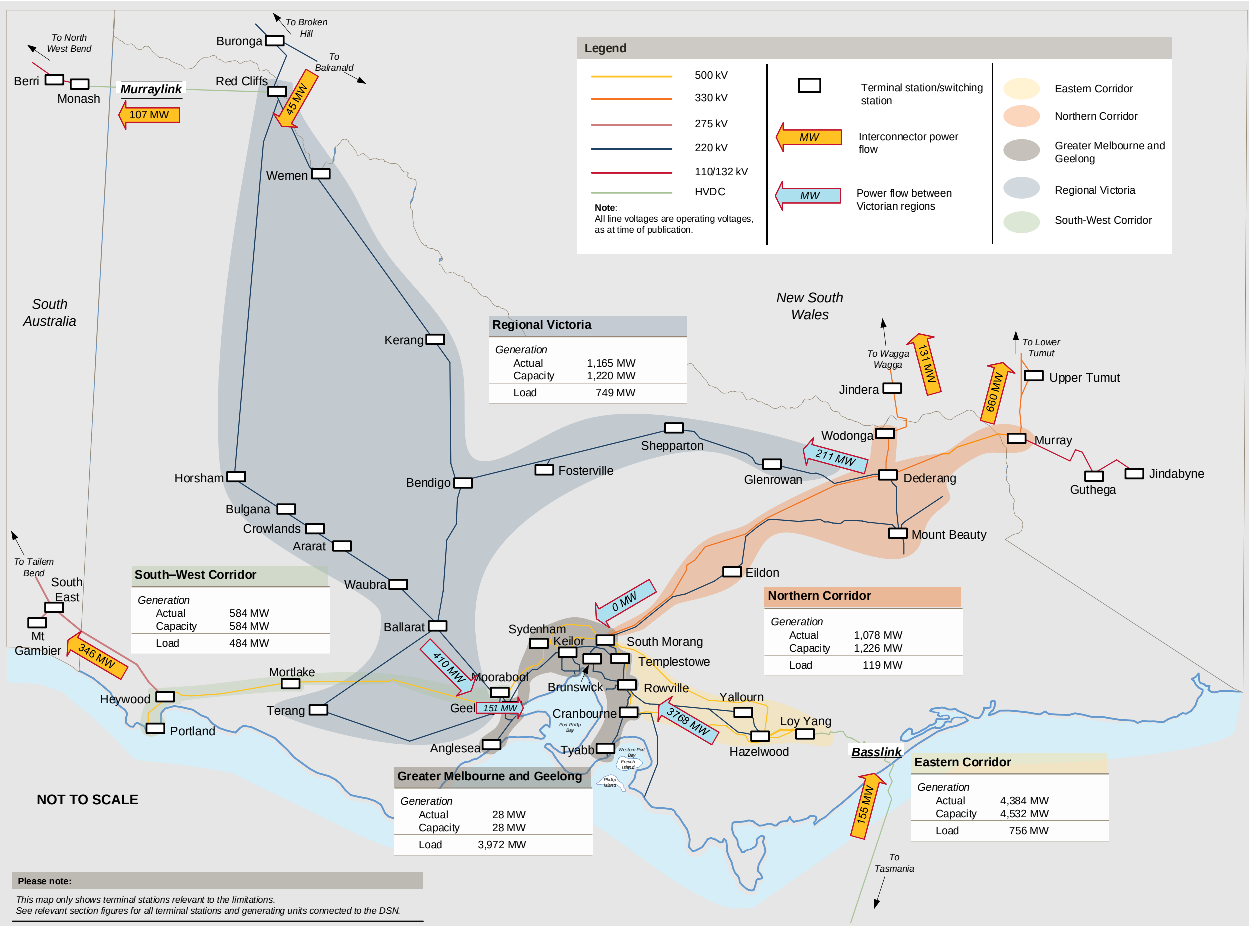
As renewable generation investment grows, new limitations are expected to emerge in several locations across southern and regional Victoria. Chapter 4 provides further information on these emerging limitations, and on AEMO's assessment of solutions that could deliver net market benefits.

Table 14 High wind snapshot – summary of operating conditions

Characteristic	Value	Notes
Victorian operational demand[A]	6,315 MW	Operational demand at the time of the snapshot was not high enough to risk thermal overload, nor low enough to develop the potential of over-voltages.
Sum of Victorian loads	6,081 MW	65% (3,972 MW) was concentrated in Greater Melbourne and Geelong.
Sum of Victorian generation	7,233 MW	61% of Victorian generation originated from the Eastern Corridor.
Sum of Victorian available generation capacity	7,590 MW	
Net power flow into Victoria via interconnection	-1044MW	• -746 MW on the VNI (New South Wales). • -346 MW on the Heywood Interconnector (South Australia). • -107 MW on the Murraylink Interconnector (South Australia). • +155 MW on the Basslink Interconnector (Tasmania).
Distributed PV	0 MW	The snapshot occurred after sunset.
Battery storage	0 MW	
Victorian renewable generation	2,857 MW	Representing 39.5% of total Victorian generation, and comprising: • 388 MW of non-scheduled wind. • 1,391 MW of dispatched wind. • 0 MW of dispatched solar. • 1,078 MW of hydroelectric generation. Total wind generation includes 1,165 MW from Regional Victoria, 584 MW from the South-West Corridor, and 30 MW from the rest of the state.
RERT dispatched	0 MW	
Other system security considerations	System normal No contingency overloads All flows within thermal limits.	

A. Operational demand is the sum of all Victorian loads and network losses.

Figure 22 High wind snapshot – generation, load, and interconnector flow



2.8.4 High export snapshot

The high export snapshot captures conditions where Victoria is supplying a high level of power flow into New South Wales. Table 15 and Figure 23 show the prevailing conditions at a time of high export from Victoria to New South Wales (10:01 pm on 15 June 2020).

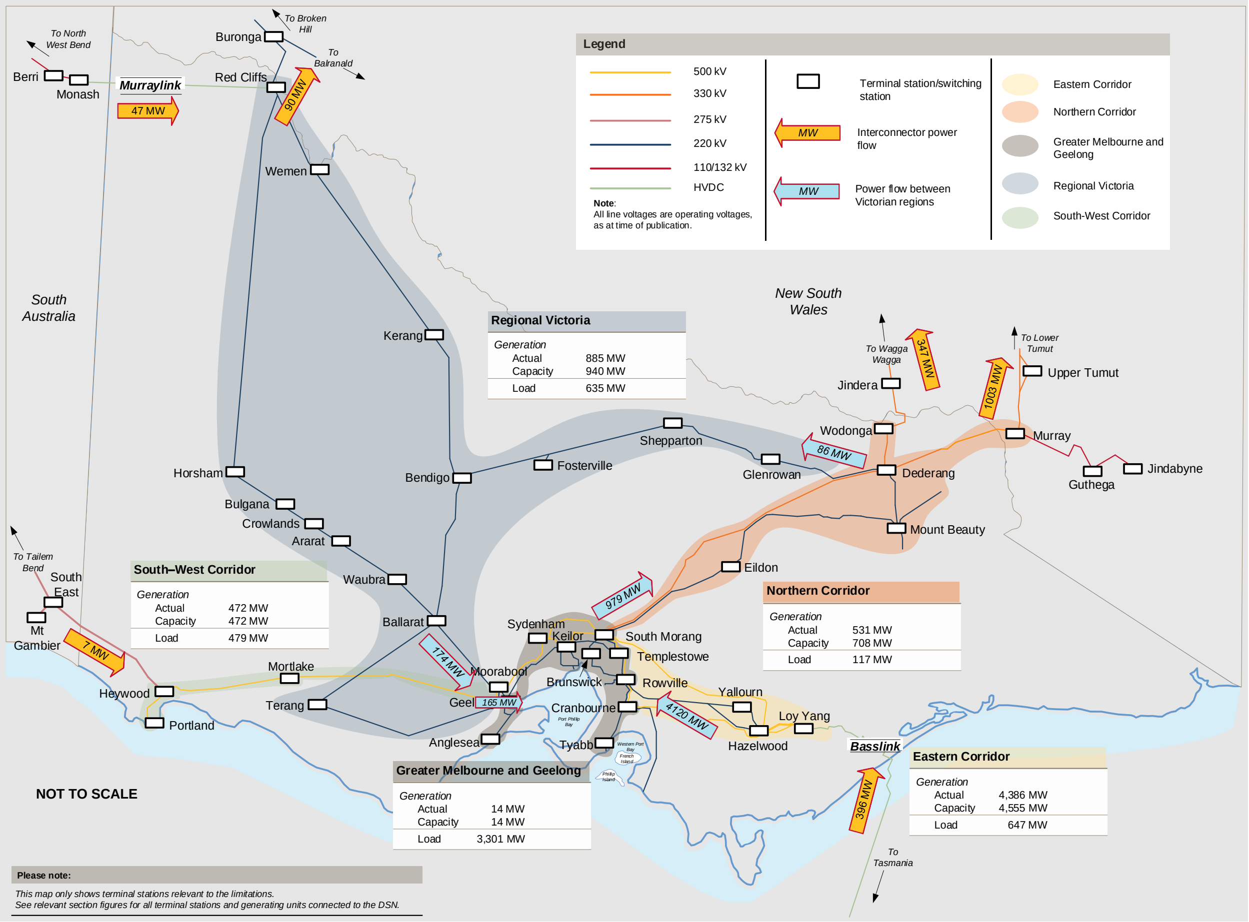
Table 15 High export snapshot – summary of operating conditions

Characteristic	Value	Notes
Victorian operational demand[A]	5,544 MW	
Sum of Victorian loads	5,179 MW	64% (3,301 MW) was concentrated in Greater Melbourne and Geelong.
Sum of Victorian generation	6,288 MW	70% of Victorian generation originated from the Eastern Corridor.
Sum of Victorian available generation capacity	6,689 MW	
Net power flow into Victoria via interconnection	-989MW	• -1,439 MW on the VNI (New South Wales). • +7 MW on the Heywood Interconnector (South Australia). • +47 MW on the Murraylink Interconnector (South Australia). • +396 MW on the Basslink Interconnector (Tasmania).

Characteristic	Value	Notes
Distributed PV	0 MW	The snapshot occurred after sunset.
Battery storage	1 MW	
Victorian renewable generation	1,926 MW	Representing 30.6% of total Victorian generation, and comprising: • +290 MW of non-scheduled wind. • +1,105 MW of dispatched wind. • +0 MW of dispatched solar. • +531 MW of hydroelectric generation.
RERT dispatched	0 MW	
Other system security considerations	System normal. No contingency overloads All flows within thermal limits.	

A. Operational demand is the sum of all Victorian loads and network losses.

Figure 23 High export snapshot – generation, load, and interconnector flow



3. Network developments

This chapter provides an update on the network investment activities and investigations that have progressed since June 2019, and which will facilitate the integration of new renewable generation while supporting Victorian power system security and reliability.

Key network development insights

The energy landscape in Victoria continues to change, driven by strong investment in large-scale renewable generation projects. New investment in the west of the state is creating additional supply centres, while an increasing penetration of non-synchronous generation continues to impact the stability and complexity of system operations.

Over 1.6 GW of renewable projects have connected in Victoria since publication of the 2019 VAPR, and are now either in full service or undergoing commissioning tests. A further 1.5 GW are committed to connect, and another 16.3 GW have reached connection enquiry phase.

To meet the forecast future needs of the system, AEMO is progressing a suite of projects across the state through its *Transmission Roadmap for Victoria*.

The 2020 roadmap consists of almost $3.5 billion in transmission investment over the coming decade, and has been designed to address transitionary issues, maintain supply reliability, deliver system security, and meet government policy objectives. These investments act to reduce overall costs to consumers by enhancing competition, unlocking lower-cost generation supplies, and improving the efficiency of resource sharing between neighbouring regions.

The roadmap comprises committed projects (those that have already passed appropriate regulatory approvals), and future projects (those where assessment and approvals are currently underway). Together these projects target key thermal, stability, voltage control, system strength, and renewable energy zone (REZ) expansion projects across the state.

There are also several noteworthy projects, delivered since the 2019 VAPR:

- Thermal upgrades – two Network Capability Incentive Project Action Plan (NCIPAP) projects that upgrade existing 220 kV lines in both the north and south-west parts of the network using dynamic line ratings. AEMO has also progressed upgrades to the Red Cliffs to Buronga 220 kV line thermal ratings.
- Control schemes – upgrades to the existing Interconnector Emergency Control Scheme (IECS) to better manage the risk of tripping multiple 330 kV and 220 kV lines during bushfires.
- Voltage stability – a new NMAS agreement for additional dynamic reactive power support which can increase Victorian imports on the VNI at times when this may avoid the need to activate emergency reserves or load shedding.
- Voltage control – AEMO has implemented an interim voltage protection scheme which will allow higher operating voltages on the 500 kV network at the Keilor Terminal Station. This will assist in managing high voltages, particularly during generator outages when other options may be exhausted.

Committed projects

Since the 2019 VAPR, AEMO has concluded several multi-year regulatory processes on projects that have now all transitioned into procurement and delivery phases:

- Voltage control – AEMO and AusNet services have committed to install four 100 MVA reactive (MVAr) reactors by 2022 to address voltage control limitations under light load conditions. The 2020 ESOO forecasts further reductions in minimum demand, which may drive the need for further investment.
- REZ expansion – in July 2019, AEMO concluded the Western Victorian Transmission Network RIT-T, to reduce network congestion and unlock additional connection hosting capacity in Western Victoria. The project is now progressing towards staged delivery between 2021 and 2025.
- Interconnection – in February 2020, AEMO and TransGrid concluded a RIT-T to unlock an additional 170 MW of export capability on the VNI to improve access to renewable generation in the southern states. This project is progressing towards delivery by late 2022.
- System strength – in August 2020, AEMO entered into NMAS agreements with two system strength service providers in the Red Cliffs area to remediate a localised system strength issue. AEMO is currently progressing a permanent solution through a market procurement activity.
- Improved system monitoring – AEMO is progressing the installation of Phasor Measurement Units (PMUs) at various locations in the DSN to provide better visibility of network performance and increase the ability to develop complex and more accurate models of the power system.
- SIPS – at the request of the Victorian Government, AEMO has taken steps to procure a system integrity protection scheme that will increase import capabilities of VNI by up to 250 MW during November to March each year.

Future projects

Regulatory testing and approvals are currently underway for:

- Interconnection and REZ expansion – AEMO and TransGrid have jointly commenced the VNI West RIT-T, to assess the economic merits of additional transfer capacity between Victoria and New South Wales. This project aims to deliver improved supply reliability, efficient development and dispatch of high-quality renewable resources, and more efficient sharing of resources between NEM regions.
- Voltage stability – AEMO is progressing an investigation into potential voltage collapse limitations in the south-west corridor, associated with increasing generation in this location, and at times of high import from South Australia.
- Interconnection – other regions are also experiencing similar challenges, and are progressing their own investment projects that could impact flows within the DSN. These include the Marinus Link project to deliver a 1,500 MW interconnector with Tasmania, and Project EnergyConnect to deliver an 800 MW interconnector with South Australia, with connection to Victoria at Red Cliffs.

The above suite of committed and future projects together forms the core of the transmission roadmap for Victoria. These projects have been designed to deliver government policy objectives and efficiently meet security requirements and maintain supply reliability, and minimise cost to consumers.

3.1 Supply changes since the 2019 VAPR

This section reviews the completed and committed changes to Victoria's fleet of generation and storage projects, since publication of the 2019 VAPR. The scale and type of these projects highlight the changing nature of the Victorian DSN, and are the key drivers for network projects discussed later in this chapter. The changes also underpin the emergence of new network limitations, which are discussed in Chapter 4.

3.1.1 Newly connected projects

The following 589 MW of large (greater than 30 MW) generator projects connected since the 2019 VAPR:

- Ballarat Energy Storage System (30 MW/30 MWh) connected at Ballarat in May 2019.
- Bannerton Solar Park (88 MW) connected via Powercor's network at Wemen in March 2019.
- Wemen Solar Farm (87.75 MW) connected via Powercor's network at Wemen in March 2019.
- Numurkah Solar Farm (100 MW) connected via Powercor's network at Shepparton, September 2019.
- Cherry Tree Wind Farm (57.6 MW) connected via AusNet Services' network at South Morang in June 2020.
- Murra Warra Wind Farm Stage 1 (225.7 MW) connected at Murra Warra Terminal Station, August 2020.

The following 1,090 MW of large generator projects have commenced commissioning since the 2019 VAPR:

- Yendon Wind Farm (144.4 MW) connected via Powercor's network at Ballarat in January 2020.
- Bulgana Wind Farm (194 MW) connected at Bulgana in May 2020.
- Mt Gellibrand Wind Farm (132 MW) connected via Powercor's network between Terang and Geelong in April 2020.
- Dundonnell Wind Farm (336 MW) connected at Mortlake Power Station, June 2020.
- Elaine Wind Farm (83.6 MW) connected to the Elaine Terminal Station, June 2020.
- Kiamal Solar Farm – Stage 1 (200 MW and 190 MVAr synchronous condenser) connected to the Kiamal Terminal Station in September 2020.

For intending applicants, AEMO's website contains the process for network connections[54], the procedure for network augmentations to cater for new connections, and the approach to request network data[55].

3.1.2 Terminal station developments to support new connections

The following projects have been completed since publication of the 2019 VAPR:

- Haunted Gully Terminal Station (Stockyard Hill Wind Farm 500 kV connection) in October 2019.
- Kiamal Terminal Station (Kiamal Solar Farm 220 kV connection) in December 2019
- Berrybank Substation (Berrybank Wind Farm 220 kV connection) in August 2020

3.1.3 Newly committed projects

Since the 2019 VAPR, the following projects have become committed, meaning they have secured land, planning and approvals (which includes signed connection agreements with AEMO), entered into contracts for finance, and have either started construction or set a firm date:

- Glenrowan West Sun Farm (105.6-132 MW) – distribution-connected.
- Winton Solar Farm (85 MW) – distribution-connected.
- Berrybank Wind Farm (180.6 MW) – DSN-connected.

Information on committed and potential generation projects can be found on AEMO's generation information page[56]. The AEMO website also contains a register of large generator connection projects[57].

[54] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/victorian-transmission-connections.

[55] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/policy-on-provision-of-network-data.

[56] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. AEMO's commitment criteria are under the Background Information tab.

[57] 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.

Connection assessments in the West Murray Zone

Detailed modelling is essential for technical assessments in weak areas of the grid, however this level of detail inevitably makes that process slower. Since the 2019 VAPR, the nature and complexity of potential interactions in the West Murray area has introduced delays in the assessment of new connection projects.

Under the current West Murray network conditions, AEMO and NSPs must study the impact of each incremental connection individually to be satisfied that further grid-scale inverter-based generation can meet performance standards without causing adverse security or quality of supply issues.

Once stability is confirmed, the model parameters and settings are finalised and integrated into the wide area PSCAD model, accessible by all relevant NSPs. At that point, the next project can be assessed.

The AEMO website provides more information on the sequencing methodology currently applied[58].

3.1.4 Retirement projects

There have been no generation or storage retirements in the DSN since publication of the 2019 VAPR. Only the Yallourn W1 coal-fired unit closure from 2029 is identified within the planning horizon[59].

3.2 Renewable energy investment

The operational landscape in Victoria is changing rapidly, with strong interest in new renewable generation projects driving the pace of this change. Victoria now has approximately 7.8 GW of existing or committed wind and solar generation, with 2.9 GW of this attributed to distributed PV installations. There are an additional 2.3 GW of existing hydro generation, and 75 MW of existing or committed battery storage[60].

Since the 2019 VAPR, over 1.6 GW of new large-scale renewable projects have connected or commenced commissioning in Victoria, and three new terminal stations have been established in response. There are a further 1.5 GW of renewable projects committed to connect, and almost 16.3 GW of projects have lodged connection enquiries[61].

Much of the growing investor interest is being motivated by the Victorian Government's VRET, which seeks to deliver 40% renewable energy generation by 2025, and 50% by 2030[62].

Figure 24 summarises Victoria's existing, committed and proposed generation projects[63].

AEMO's 2020 ISP found that at least 13.2 GW in renewable generation would be required to deliver the VRET under its Central scenario when using the latest demand forecasts (see Figure 25).

This represents up to 5.4 GW of additional renewable investment, spread between large-scale and distributed resources. An additional 600 MW of large-scale plant has already become committed since the ISP analysis.

While the ISP's Step Change scenario[64] has not yet been remodelled with the latest ESOO demand forecasts, it built up to 14.1 GW of total renewable capacity in Victoria under 2019 demand forecast assumptions.

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[58] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/west-murray.

[59] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[60] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

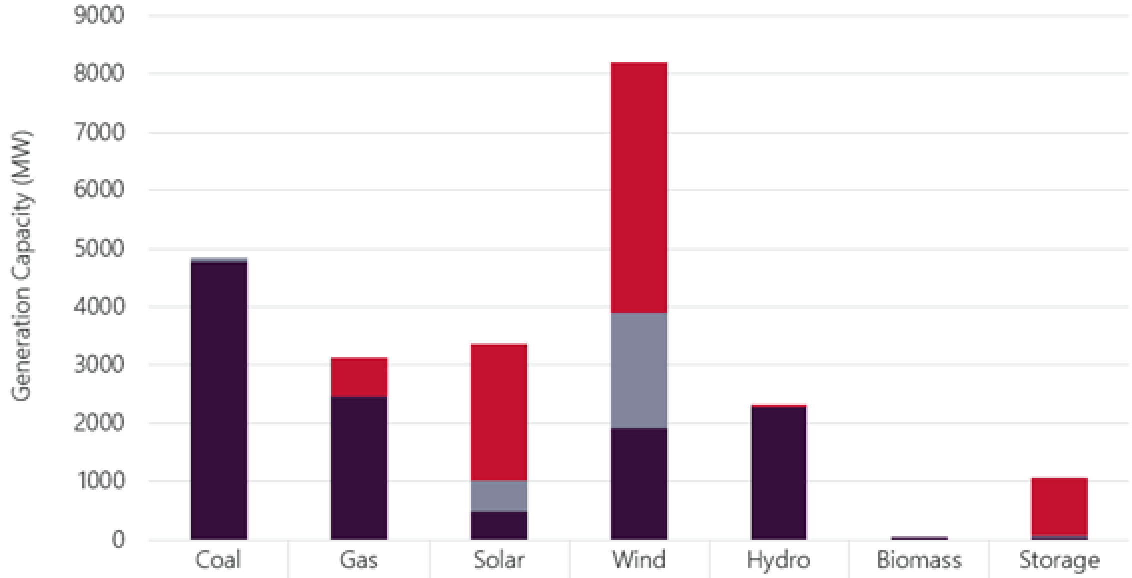
[61] As at September 2020, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/NEM-generation-maps.

[62] See https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

[63] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[64] The Step Change scenario reflects a faster energy market transition and aligns with global ambitions to decarbonise to meet the Paris Agreement. For more on modelling scenarios and assumptions, see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

Figure 24 Existing, committed and proposed large-scale generation capacity in Victoria, 20 July 2020



	Coal	Gas	Solar	Wind	Hydro	Biomass	Storage
Proposed		650	2344	4304	34		992
Committed*	60		546	1994			20
In Service	4775	2477	478	1911	2292	58	55

Note: Committed includes those projects that are currently undergoing the commissioning process.

Figure 25 Renewable development in the ISP Central (updated demand) scenario by 2029-30

3.3 Transmission Roadmap for Victoria

To address the emerging operational issues highlighted in Section 2.5 and Section 2.6, and to deliver a system capable of facilitating the supply changes identified in Section 3.2, AEMO is progressing a suite of projects across the state through its *Transmission Roadmap for Victoria*.

Projects in the roadmap are intended to facilitate the connection of new generators, increase potential sharing of resources across region boundaries, and manage emerging operational concerns before they arise. It has been designed to efficiently deliver policy objectives, meet system security requirements, maintain supply reliability, and minimise overall costs to consumers.

The roadmap itself can be divided into two sections:

- **Committed projects** – focusing on near-term upgrades that have already passed appropriate regulatory approvals, and comprising nine initiatives that target key thermal, stability, voltage control, system strength, and REZ expansion projects across the state.
- **Future projects** – focusing on mid- and long-term projects that are currently progressing through design and regulatory testing processes. These include all relevant projects identified as part of the 2020 ISP optimal development path.

Figure 26 and Figure 27 summarise AEMO's 2020 *Transmission Roadmap for Victoria*. The rest of this chapter provides specific details about each roadmap project individually.

Delivered projects

The following roadmap projects have already been completed since publication of the 2019 VAPR:

- NCIPAP project to upgrade the Ballarat – Waubra – Ararat – Horsham 220 kV line to increase its thermal rating, including the ability for wind monitoring to input into dynamic ratings, was completed in October 2019; the rating was increased from 440 MVA to 493 MVA.
- NCIPAP project to upgrade the Horsham – Red Cliffs 220 kV line to increase its thermal rating, including the ability for wind monitoring to input into dynamic ratings, was completed in October 2019; the rating was increased from 312 MVA to 395 MVA.
- Heywood Interconnector upgrade (ElectraNet project) to increase Heywood limit for South Australia to Victoria flows was completed in December 2019; the limit was increased from 500 MW to 550 MW and the combined (Heywood and Murraylink) limit was increased from 650 MW to 700 MW[65].
- A project to upgrade the Red Cliffs – Buronga (OX1) 220 kV line to increase its thermal rating from 312 MVA to 456 MVA was completed in June 2020.
- A new generation tripping component was added to the existing Interconnector Emergency Control Scheme (IECS), which manages the risk of trip of multiple 330 kV and 220 kV lines during bushfires, to avoid load shedding and cascade failures. This became fully operational in early July 2020.
- A new NMAS agreement was established for additional dynamic reactive power support which can increase the New South Wales to Victoria voltage stability limit when such action would avoid the need to activate emergency reserves or load shedding.
- AEMO has implemented a voltage protection scheme which will allow higher operating voltages on the 500 kV network around Keilor Terminal Station. This will assist in managing high voltages, particularly during concurrent generator outages when other options may be exhausted. Section 2.5.2 provides further information on the need for this scheme.
- A new post-contingent generation fast tripping (GFT) scheme that reduces the post contingent loading on the Red Cliffs – Wemen – Kerang 220 kV line for a credible contingency was implemented in August 2020.

[65] AEMO, Market Notice 71869, December 2019, at https://www.aemo.com.au/market-notices?marketNoticeQuery=71869&marketNoticeFacets=POWER+SYSTEM+EVENTS%2CPROCESS+REVIEW%2CCONSTRAINTS.

Figure 26 Transmission roadmap – committed and recently delivered projects

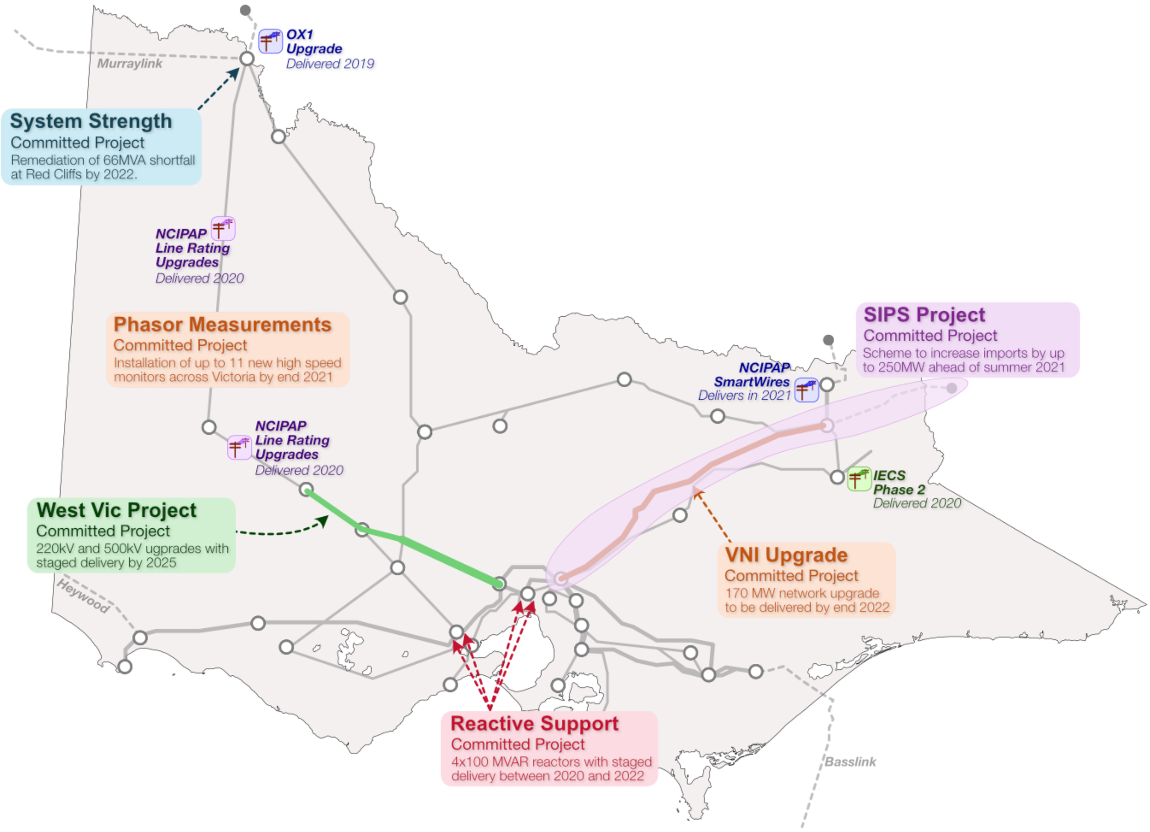
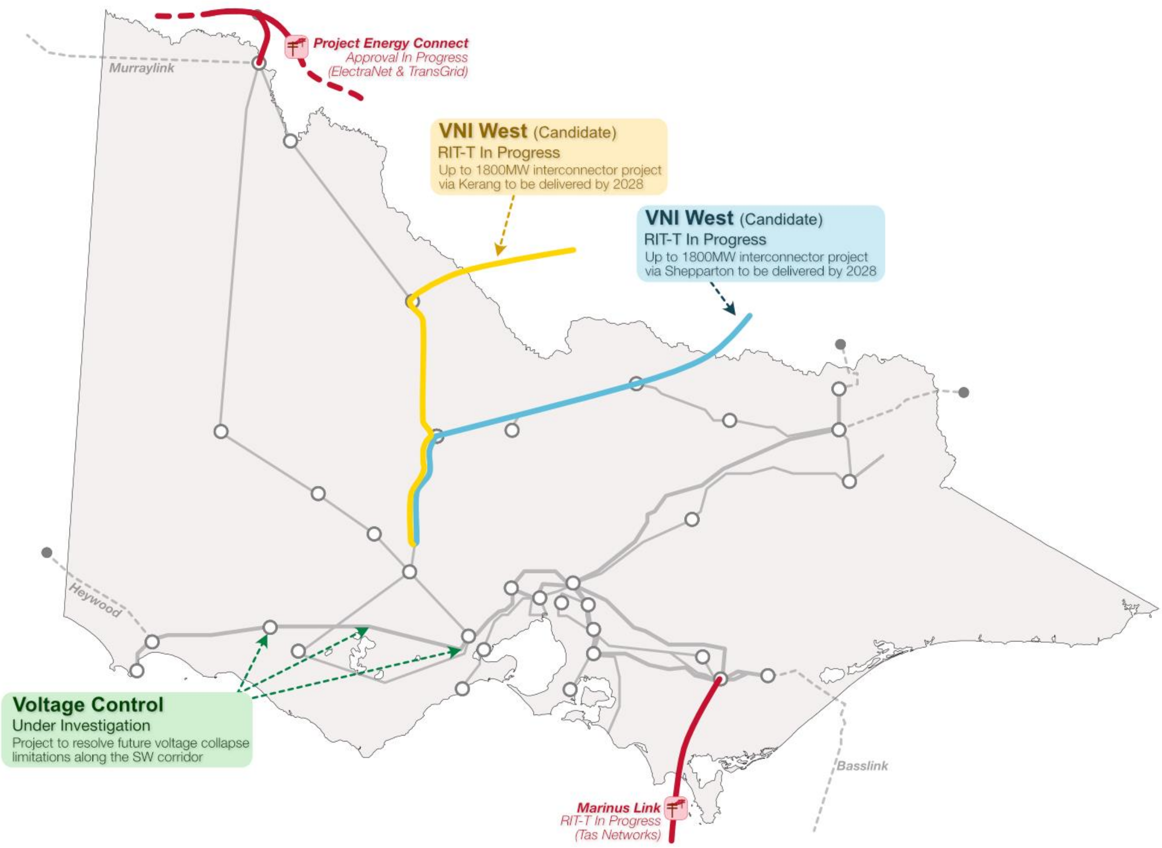


Figure 27 Transmission roadmap – further projects under assessment



3.3.1 Committed project: Western Victorian Transmission Network RIT-T

The Western Victoria region is experiencing significant renewable generation development, with large amounts of additional generation expected to be operational in the near future. However, the transmission infrastructure in this region is insufficient to allow efficient access to all generation seeking to connect. In July 2019, AEMO completed a RIT-T to unlock renewable energy resources, reduce network congestion, and improve utilisation of existing assets in western parts of Victoria[66].

Project details

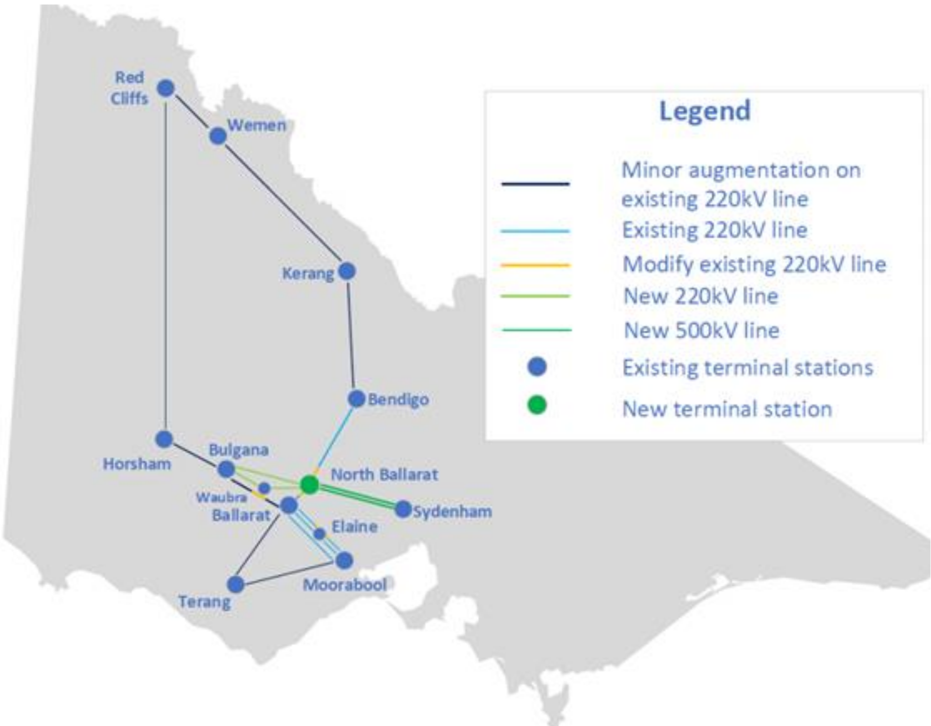
The Western Victoria Transmission Network Project, shown in Figure 28, consists of:

- Minor transmission line augmentations to the 220 kV network, to be delivered by 2021.
- A new terminal station north of Ballarat and new 220 kV double circuit transmission lines from this station to Bulgana (via Waubra), to be delivered by 2024.
- New 500 kV double circuit transmission lines from Sydenham to the new terminal station north of Ballarat, connecting two new 1,000 MVA 500/220 kV transformers, to be delivered by 2025.

Project status

In December 2019, AusNet Services was awarded a contract to consult on, design, seek planning approvals for, build, own, operate and maintain the transmission augmentations identified by the RIT-T. AusNet Services has commenced planning and environmental investigations within the project's area of interest, and is currently engaging with potentially affected landowners. The latest project information is available on AusNet Services' dedicated project website[67]. The project remains on track for delivery by 2025.

Figure 28 Preferred option from Western Victorian Transmission Network RIT-T



Note: visual representations of geographic locations are indicative only. Locations will be determined as required during detailed design, route assessment, planning, and community engagement processes.

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[66] See https://aemo.com.au/initiatives/major-programs/western-victorian-regulatory-investment-test-for-transmission.

[67] See https://www.westvictnp.com.au/.

3.3.2 Committed project: 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 have become necessary to maintain voltages within operational limits. Section 2.5.2 discusses the increase in frequency of these interventions. In December 2019, AEMO completed a RIT-T to deliver the required additional reactive support[68].

Project overview

The Reactive Power Support Project consists of:

- One additional 220 kV 100 MVAr shunt reactor at Keilor Terminal Station.
- Two additional 220 kV 100 MVAr shunt reactors at Moorabool Terminal Station.

A 220 kV 100 MVAr reactor will also be installed at Keilor Terminal Station as part of a NCIPAP.

Current status

In September 2020, AEMO engaged AusNet Services to procure, own, operate and maintain the equipment identified by the RIT-T. AusNet Services is now undertaking procurement activities, with all assets on track for staged delivery and commissioning ahead of summer 2022-23.

The 2020 ESOO[69] forecasts a dramatic reduction in minimum demand over the coming decade. This will act to increase benefits of delivering this project. The forecasts may also signal the need for further investment in the late 2020s, and AEMO will continue to monitor actual demand trends against demand forecasts.

3.3.3 Committed project: VNI Upgrade

Power transfers from Victoria to New South Wales are restricted by thermal, voltage stability, and transient stability limitations (see Section 2.6). Resolving these limitations will allow more efficient sharing of resources between regions, and improve supply adequacy following the Liddell Power Station retirement in 2022-23.

In February 2020, AEMO and TransGrid completed a RIT-T[70] that assessed network and non-network options to address the transfer capacity of the existing VNI Interconnector.

Project overview

The VNI Upgrade project consists of the following augmentations:

- Installation of a second 500/330 kV transformer at South Morang Terminal Station.
- Re-tensioning of the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors), to allow operation at thermal rating.
- Installation of modular power flow controllers on the 330 kV Upper Tumut to Canberra and Upper Tumut to Yass lines to balance power flows. This work will be undertaken by TransGrid in New South Wales.

Current status

In June 2020, AEMO engaged AusNet Services to progress the Victorian components of the project for completion by late 2022. TransGrid is separately progressing regulatory approvals to commence works in New South Wales. AEMO is currently considering the scope and need for any inter-regional testing activities.

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[68] AEMO, Victorian Reactive Power Support, December 2019, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/2019/reactive-power-rit-t/victorian-reactive-power-support-pacr.pdf.

[69] AEMO, 2020 ESOO, July 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2.

[70] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/2020/vni-rit-t/victoria-to-new-south-wales-interconnector-upgrade-rit-t-pacr.pdf?la=en&hash=0564037FF5BFD025B8A8E7EA3CBD9743.

3.3.4 Committed project: Red Cliffs System Strength Remediation Project

On 13 December 2019, AEMO published a notice of fault level shortfall[71] at Red Cliffs Terminal Station under clause 5.20C.2(c) of the NER. AEMO further revised this shortfall on 6 August 2020 due to updated projections of available fault levels at Red Cliffs[72].

The revised notice specified an immediate fault level shortfall (also referred to as a system strength gap) of at least 66 MVA, which would continue beyond 2024-25 if not addressed.

As the System Strength Service Provider for Victoria, AEMO is responsible for procuring services to address this declared shortfall. Under the NER, remediation of a declared system strength gap does not require a RIT-T process where that gap is forecast to occur within 18 months. In such cases, the System Strength Service Provider (AEMO in this case) must use reasonable endeavours to remediate the gap as quickly as possible, and using the least-cost solution.

Project overview

AEMO has progressed remediation activities in two stages:

- An initial (two-year) solution targeting interim services from providers with known capability to provide system strength services under an NMAS agreement.
- A parallel expression of interest and tender process seeking a long-term solution, which may include a combination of network and non-network investments.

Project status

In August 2020, AEMO secured interim services from two facilities in the West Murray region under fixed-term contracts for at least two years. This completely remediates the declared gap for that period.

In September 2020, AEMO published a call for expressions of interest to procure a longer-term solution[73] which aims to be in service by 31 July 2022, but no later than 31 July 2023. The successful providers may be located at one or multiple locations in north-west Victoria and south-west New South Wales.

3.3.5 Committed project: Phasor Measurement Units

Rapid investment in large-scale inverter-based generation across Victoria, coupled with the ongoing uptake of distributed PV, have introduced complex operational challenges that make it increasingly difficult for AEMO to meet its power system security obligations without imposing significant network limitations.

One key factor in this decreased effectiveness is a lack of PMUs and high-speed monitors (HSMs) available for key transmission assets, leading to low visibility of intra- and inter-area power system oscillations in the Victorian region.

AEMO and AusNet Services are progressing a project to deliver up to 11 new PMUs in strategic locations across the state. This project will:

- Provide better visibility of network performance in real time, and in post-incident analysis.
- Increase AEMO's ability to develop and benchmark complex models of the power system.

AEMO and AusNet Services are currently finalising the technical specifications and target locations. Delivery and commissioning of the associated equipment is expected in 2021.

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[71] AEMO, *Notice of Victorian Fault Level shortfall at Red Cliffs*, December 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice_of_Victorian_Fault_Level_Shortfall_at_Red_Cliffs.pdf.

[72] AEMO, *Notice of Change to System Strength Requirement and Shortfall at Red Cliffs*, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en&hash=5C3EDDABDF81891B3989F6FF0466C486.

[73] AEMO, *Call for Expressions of Interest Victorian System Strength*, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-transmission-network-service-provider-role/call-for-expressions-of-interest-victorian-system-strength.

3.3.6 Committed project: System Integrity Protection Scheme (SIPS) 2020

The Victorian Parliament has amended the NEVA, allowing priority projects to be fast-tracked to deliver augmentation projects, or non-network services with respect to the DSN[74].

Under this amendment, the Minister for Energy, Environment and Climate Change has new powers to modify or disapply sections of the NEL and the NER as they relate to specified augmentations, specified augmentation services or specified non-network services in respect of the Victorian DSN.

Project overview

The Victorian Government has used the NEVA legislation to request that AEMO take steps to procure a 250 MW SIPS ahead of summer 2021-22 to increase import capability across the VNI[75].

The SIPS service achieves this by rapidly responding to inject power after a contingency event on VNI. This allows VNI to run to its 5-minute thermal rating, rather than the more conservative 15-minute ratings that would typically apply.

Project status

AEMO issued an Invitation to Tender in April 2020, and this process concluded in November 2020. The successful tenderer was global renewable energy producer, Neoen, and the service is intended to be available ahead of Summer 2021-22.

3.3.7 Future project: VNI West

AEMO's 2020 ISP[76] sets out an optimised national pathway for development of the power system that maximises the value of new and existing resources, while delivering reliable energy at the lowest cost to consumers. This pathway incorporates signposts and decision rules to respond to economic, technical, environmental, and policy changes.

The 2020 ISP identifies that both short-term and longer-term investments are required to increase interconnection capacity between Victoria and New South Wales. This interconnection allows more efficient sharing of resources between states, reduces the need for generation investment to maintain supply reliability, and promotes dispatch outcomes that deliver energy at the lowest cost to consumers.

As described in Section 3.3.3, AEMO and TransGrid are already jointly progressing the delivery of a minor VNI upgrade to address immediate needs. However, the ISP also identified that a longer-term investment would be required to strengthen bidirectional interconnection between the states.

In 2020, the VNI West project was identified as an Actionable ISP project with decision rules and early works staging. The 2020 ISP recommends that early works should commence as soon as possible for completion by late 2024, enabling project delivery by 2027-28 subject to the specified decision rules.

This approach balances the costs of early investment with the long lead times required to deliver major transmission infrastructure, and the potential downside risk of delivering such projects too late. The approach also ensures minimal costs are incurred early, while allowing the project to pause or accelerate if future ISPs require change in direction or timing.

In December 2019, AEMO and TransGrid jointly published a PSCR, commencing the VNI West RIT-T[77].

This augmentation is expected to deliver fuel cost savings, facilitate efficient connection of new renewable generation, and maintain system security and reliability in Victoria. It provides a prudent pathway to access dispatchable capacity[78] and mitigates risks associated with early withdrawal of a major generator.

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[74] See https://www.legislation.vic.gov.au/as-made/acts/national-electricity-victoria-amendment-act-2020.

[75] See https://aemo.com.au/en/initiatives/major-programs/victorian-government-sips-2020.

[76] See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

[77] See https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/VNI-West-RIT-T/VNI-West_RIT-T_PSCR.pdf.

[78] Dispatchable resources include utility-scale pumped hydro, large-scale battery storage, distributed batteries, and virtual power plants (VPPs).

EnergyAustralia has advised that Yallourn Power Station is expected to close its four units in stages from 2029 to 2032, which will remove almost 1.5 GW of supply from Victoria. This is expected to bring forward projected supply shortfalls in Victoria, making it more difficult to maintain reliability without further investment.

Project overview – the identified need

The identified need being addressed by the VNI West RIT-T is to deliver additional transfer capacity between Victoria and New South Wales, to realise net market benefits through:

- Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation – including mitigation of the risk that existing plant close earlier than expected.
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales, through improved network capacity.
- Enabling more efficient sharing of resources between NEM regions.

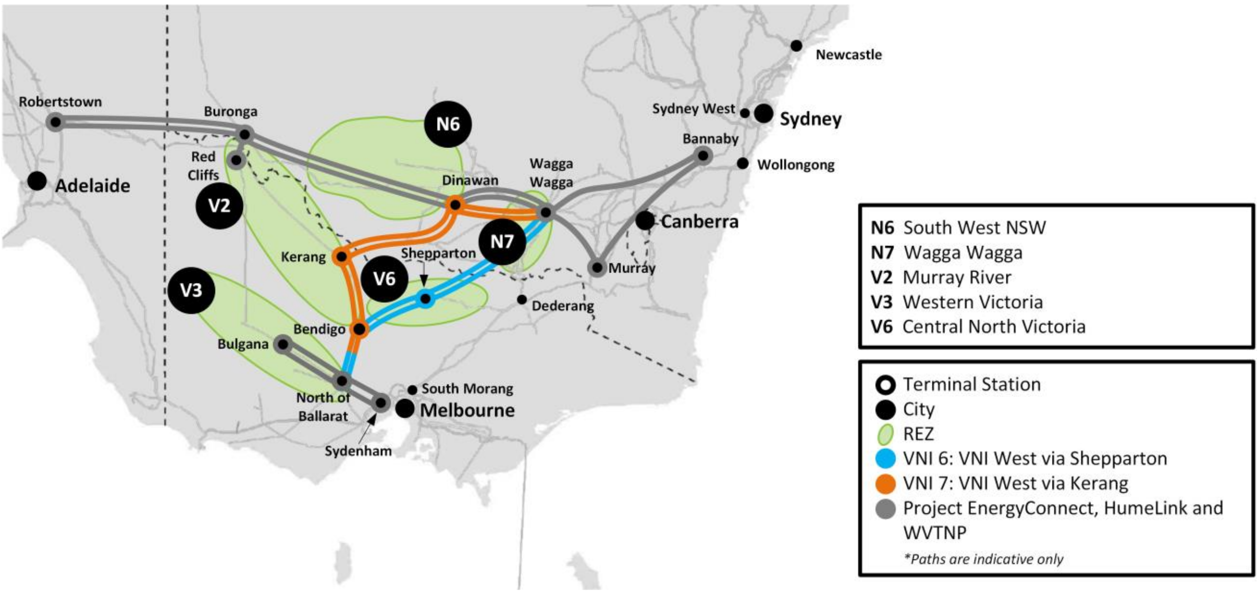
In accordance with the Australian Energy Regulator's (AER's) RIT-T guidelines, the identified need is defined as an objective, rather than a means to achieve that objective. This is to prevent biasing the development of credible options towards a particular solution, and allows the RIT-T to test a range of credible options and compare their benefits through economic analysis. The PSCR and 2020 ISP considered a broad range of credible options which provided notional transfer improvements of between 800 MW and 1800 MW.

Project overview – options analysis

The 2020 ISP[79] considered a range of credible network options to meet the identified need. Out of this broader set of options, two candidates were identified as delivering the highest net market benefits. These options, as shown in Figure 29, are:

- **VNI West via Shepparton**, a double circuit 500 kV line from a new substation north of Ballarat to Wagga Wagga, via Shepparton.
- **VNI West via Kerang**, a double circuit 500 kV line from a new substation north of Ballarat to Wagga Wagga, via Kerang and Dinawan.

Figure 29 VNI West project, ISP preferred options



Note: descriptions and visual representations of geographic locations are indicative only. Locations will be determined after the conclusion of the RIT-T process, as required during detailed design, route assessment, planning, and community engagement activities.

[79] See AEMO, 2020 ISP, Appendix 3, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en.

Despite differences in costs, both options yield similar net market benefits, and further analysis is being undertaken through the RIT-T to distinguish between these two options.

There are a number of additional factors which may influence this outcome, including changes in government policy, diversity and resilience benefits, the location of new generation or storage investments in Victoria, and any land, planning, or environmental considerations.

Non-network options

The VNI West RIT-T PSCR sought submissions from providers of non-network solutions that may be capable of addressing all or part of the identified need. Through the consultation process, AEMO and TransGrid engaged with a number of such providers who made submissions, and have explored how these options should be considered as part of VNI West.

This feedback has now been incorporated, and both power system and market modelling is being undertaken to assess credible non-network options. This work aims to identify the optimal size, technology, location, and staging that could address the identified need and deliver market benefits.

In particular, the RIT-T is investigating the benefits of a virtual transmission line, which involves the installation and pairing of two battery energy storage solutions at two substations to relieve the limitations on the existing New South Wales to Victoria interconnector. AEMO and TransGrid will continue to progress this analysis over the coming months and publish the outcomes of this analysis in the PADR.

Alternate options

A number of alternative credible network options were assessed and found uneconomic through the ISP process (see Section A3.8.2 in Appendix 3 of the 2020 ISP). The ISP recommends that the VNI West RIT-T should exclude network options that have already been tested and discounted through this ISP, focusing instead on refining the design and assessment of the optimal ISP candidate options.

Reasonable variations of the two candidate options will also be tested, particularly where they may reduce cost or risk. These variations could change the project's terminal stations, or specific design features for each option. The scope of any variations will be outputs from the power system modelling studies, detailed engineering design works, or land planning and environmental assessments.

AEMO and TransGrid are also testing the feasibility of implementing non-traditional network solutions to maximise the benefits of each option. Specifically, analysis is being undertaken to assess the viability of replacing traditional power flow control solutions with modular power flow control technology, which may deliver a more flexible solution. The outcome of this assessment will be published in the PADR.

Lessons from previous RIT-Ts

AEMO and TransGrid are applying a range of detailed activities in this RIT-T to provide certainty in the robustness of the outcomes, and that any delivered network upgrades will deliver the projected consumer benefits once commissioned. These activities include:

- Power system analysis – to capture the complexities of operating a power system with increasing levels of renewable penetration, more extensive power system studies are being performed to test system limits (thermal, voltage stability, transient and oscillatory stability) across a broad range of system conditions.
- Design and estimation – each credible option has been informed by a range of desktop due diligence studies to identify known land, planning and environmental constraints. This was undertaken to ensure each credible option had considered likely land, planning and environmental matters in developing reasonable time and cost estimates, as well as allowing relative comparisons between the options.

These activities are not typically performed as part of the RIT-T process, but will ensure the outcomes of the RIT-T are robust, resilient, and realisable. Modelling activities are still underway, and detailed supporting material will be published alongside the draft preferred option for consultation in the PADR by March 2021.

RIT-T analysis under the Actionable ISP

The ISP framework, as set out in the NER[80] and AER Guidelines[81], seeks to minimise duplication between the ISP and RIT-Ts by implementing several new requirements, interactions, and feedback loops. AEMO is required to consult extensively on its inputs, assumptions and analysis approach in preparing the ISP, while the RIT-T is then required to leverage these settings to maintain alignment and national consistency.

Given the alignment of input assumptions, and considering that the ISP already explores a broad range of network options and scenarios, the AER Guidelines aim to reduce the need for any duplicative analysis in the RIT-T. In particular, this allows the RIT-T proponent to discount options that have already been tested through the ISP, and to model a reduced set of scenarios. The ISP is required to specify which scenarios are most relevant to consider for each application of the RIT-T.

For VNI West, the ISP recommends that both candidate options are tested under the Central ISP scenario, with updated demand, an early Yallourn closure, and assuming that decision rules are satisfied.

The ISP and AER Guidelines also specify how other network investment projects are to be treated in RIT-T studies, and in particular these guidelines act to ensure that the benefits of each project are clearly understood in isolation, and quantified in a way that avoids any double-counting of benefits.

Current status

AEMO and TransGrid are continuing to progress PADR modelling, design, and cost estimation works in accordance with the guidance and requirements specified in the 2020 ISP.

In particular, the ISP identifies VNI West as an Actionable ISP project with decision rules that allow for adaptation if circumstances change. Due to long lead times, the ISP advises that it is prudent to commence VNI West early works immediately in order to mitigate the risk of delivering too late if other market conditions change rapidly. VNI West is specified as a single RIT-T project with the following parameters:

- Complete early works by late 2024, and
- Complete the project by 2027-28, unless decision rules require pausing or cancellation. The decision rules that would result in VNI West being paused or cancelled include:
  - Transmission costs exceeding $2.6 billion, based on 2020 ISP assumptions, or
  - Sufficient new market-based dispatchable capacity being in place in Victoria ahead of the next brown coal closure in Victoria, or
  - The Slow Change scenario unfolding, which includes life extensions of existing coal-fired generation.

As determined by the 2020 ISP, VNI West early works include all feasibility, design and approvals phases, and provide flexibility in timing of the subsequent construction phase. Initial estimates of the costs of these preliminary activities lie between $150 million and $200 million; this will be further refined through the RIT-T.

Consistent with the ISP recommendations, publication of the PADR is planned no later than March 2021. This report will recommend a proposed preferred option, and provide supporting technical, economic, and modelling information for consultation. Subject to the decision rules outlined above, AEMO and TransGrid are targeting project completion as soon as practicable. Early works are planned complete in late 2024 to enable delivery of VNI West from 2027-28.

[80] COAG Energy Council, Actionable ISP Rule change, March 2020, at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20Final%20Approved%20ESB%20Recommended%20National%20Electicity%20Amendment%20%28ISP%29%20Rule%202020.pdf.

[81] AER, Final decision Guidelines to make the Integrated System Plan actionable, August 2020, at https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Guidelines%20to%20make%20the%20ISP%20actionable%20-%2025%20August%202020.pdf.

3.4 Neighbouring TNSP projects

3.4.1 ElectraNet's Project EnergyConnect

Project EnergyConnect is a proposed 800 MW interconnector between South Australia and New South Wales, with connection to Victoria at Red Cliffs. The project is aimed at reducing the cost of providing secure and reliable electricity across the NEM, while facilitating a longer-term transition to low emission energy sources. In February 2019, ElectraNet completed its RIT-T assessment of this project[82].

Project overview

Project EnergyConnect broadly consists of:

- A new 330 kV interconnector from Robertstown in mid-north South Australia to Wagga Wagga in New South Wales, via Buronga.
- A new 220 kV circuit between Buronga in New South Wales and Red Cliffs in Victoria.

Project status

The AER approved the outcomes of this RIT-T in January 2020.

Since formal completion of the RIT-T, there have been some changes to both the project cost and input assumptions, compared with what was assessed in the RIT-T. ElectraNet and TransGrid are currently reviewing whether there has been a material change of circumstances that would trigger further modelling.

Implications for Victorian DSN performance

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 hosting capacity for renewables in the Murray River area, improve system strength in the area, and deliver increased network flexibility in managing network constraints.

3.4.2 TasNetworks' Marinus Link

Marinus Link is a proposed 1,500 MW high-voltage direct current (HVDC) interconnector between Tasmania and Victoria as part of Hydro Tasmania's proposed Battery of the Nation project[83]. This project is proposed to allow additional renewable generation and storage capability to be exported to the mainland.

In July 2018, TasNetworks published a PSCR as the first step of the RIT-T, and the PADR report was published in December 2019, identifying the preferred option for consultation.

Project overview

TasNetworks is proposing to deliver Marinus Link as two stages:

- An initial 750 MW HVDC link between Burnie in Tasmania and Hazelwood in Victoria with associated AC transmission network augmentations in Tasmania in 2028.
- A further 750 MW DC link connected along the same route in 2032.

The PADR noted 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 regions has the potential to deliver significant net market benefits.

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

[83] Further information on the Marinus Link project can be found on TasNetworks' Marinus Link website, at https://www.marinuslink.com.au/.

Project status

The 2020 ISP identifies Marinus Link is an Actionable ISP project, recommending early works to commence as soon as practicable, and with each of the future project stages subject to decision rules. The ISP advises that early works should be progressed such that the first cable can be completed as early as 2028-29 and no later than 2031-32. This requires delivery of early works for both cables to be completed prior to a final investment decision in 2023-24.

The ISP's recommended process and decision rules for this project are as follows:

- Complete early works on both cables by no later than 2023-24.
- To proceed from early works to construct the first cable:
  - There should be successful resolution as to how the costs of the project will be recovered (from consumers or other sources), and
  - Either the Tasmanian Renewable Energy Target (TRET) is legislated, or, either the Step Change or Fast Change scenario unfolds.
- Decision rules for Marinus Link to construct the second cable will be specified in the 2022 ISP.
- If the above decision rules are not met, the project schedule will need to be revisited.

Implications for Victorian DSN performance

AEMO has conducted a high-level assessment of the impact Marinus Link might have on the Victorian DSN if connecting in the Latrobe Valley. Preliminary studies indicate a connection at Hazelwood 500 kV would have a low impact on local constraints, given that the existing local network infrastructure was used to accommodate Hazelwood Power Station with approximately 1,800 MW generation output before its retirement in 2017.

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 explores potential new limitations that may reduce system performance, impact efficient asset utilisation, or result in additional network constraints.

Key forecast limitation insights

AEMO's *Transmission Roadmap for Victoria* has been designed to deliver policy, security, and reliability objectives in a least-cost way over the coming decade. This means it is not necessarily designed to remove all network congestion – particularly where generation investments occur in weaker parts of the grid or outside the least cost development plan considered in the ISP and VAPR.

AEMO proactively identifies future limitations through its operational, planning, and connection functions. When identified, a new limitation will trigger further investigation or prefeasibility studies. Projects are added to the roadmap as they meet regulatory approval hurdles.

The annual VAPR provides an opportunity to build on these investigations, and undertake a full scan of the Victorian power system. The VAPR uses detailed analysis to capture the nature, timing, impact, and triggers associated with potential limitations. The focus of this work is on identifying projects that are most likely to deliver net economic benefits under the current regulatory framework, while minimising costs to consumers.

Priority limitations

In 2020, AEMO has identified several limitations with potential economic merits for remediation, and intends to progress these to prefeasibility studies following VAPR publication:

- High overloading of the Ballarat – Terang – Moorabool 220 kV line for a credible contingency (trip of the Moorabool – Terang line), due to additional new generation connections.
- High overloading of the Horsham – Murra Warra 220 kV line for a credible contingency (trip of Bendigo – Kerang line), due to additional new generator connections between Horsham and Kerang, which may require renewable generation to be constrained.
- High overloading of the Red Cliffs – Wemen – Kerang – Bendigo 220 kV line for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line), due to additional new generator connections between Kiamal and Kerang, which may require local generation to be constrained.
- Voltage instability/collapse around Wemen Terminal Station for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line), due to additional new generator connections between Kiamal and Wemen, which may require variable renewable energy (VRE) to be constrained.

Developing limitations

Several new limitations have also moved to further analysis or investigation following the VAPR analysis:

- Voltage oscillation in western and north-western Victoria during prior outages.

- Overloading of the Dederang – Glenrowan – Shepparton – Bendigo 220 kV line for a credible contingency (trip of a Dederang – Glenrowan 220 kV line), at high import from New South Wales.
- Overloading of the Moorabool 500/220 kV transformer for a credible contingency (tripping of the other Moorabool 500/220 kV transformer), due to new connections on the 500 kV lines west of Moorabool Terminal Station.
- High rate of change of frequency (ROCOF) in South West Victoria constraining generators on the 500 kV lines west of Moorabool during prior outage of one of these lines, and for a credible contingency (trip of one of the 500 kV lines west of Moorabool).
- High voltages in Metropolitan Melbourne and South West Victoria caused by low demand conditions forecast by the 2020 ESOO and possible withdrawal of a large load.
- Minimum fault level requirements at Thomastown and Loy Yang Terminal Stations caused by lower demand or potential early retirement of thermal generation.
- AEMO is investigating the potential of a new voltage collapse limitation in South West Victoria (tripping of the Moorabool – Haunted Gully 500 kV line), due to additional generator connections and under high import from South Australia.

AEMO continues to monitor a range of future limitations which may trigger further study under specific system changes or generator investment patterns. AEMO has also commenced work on a *REZ Development Plan* to understand how alternative geographic patterns of generator investment might impact the optimal transmission build for the state. The *REZ Development Plan* is discussed further in Chapter 6, and takes the monitored limitations identified in this chapter as an input.

4.1 Methodology

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. The overall planning approach is described below, and the identified limitations are discussed in the following sections.

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 (See Chapter 2.6).
- Reviewing future network performance under a range of demand and generation scenarios considering government policy and economic growth projections through exploratory studies.

For the purposes of the VAPR, a limitation is defined as a network element or location that:

- Is loaded to 90% of its continuous rating, or experiences voltages outside its normal voltage range, during system normal operating conditions.
- Is loaded to 90% of its short-term rating, or experiences voltages outside its contingency voltage range, following a contingency event.
- Does not maintain the minimum three phase fault level for that location for at least 99% of the year.
- Has voltage unbalance levels which do not meet the requirements outlined in S5.1a.7 of the NER.
- Has typical inertia dispatched being less than the secure operating level of inertia, where the typical inertia is the value at one standard deviation below the mean and the secure operating level of inertia is the minimum level of inertia required to operate an islanded inertia sub-network in a secure operating state[84].

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[84] For more information see *Inertia Requirements Methodology Inertia Requirements and Shortfalls*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

Exploratory studies are carried out to identify DSN thermal and voltage control limitations that may emerge over the next 10 years. Screening studies are used to identify expected limitations, while trigger studies are used to test the system under more extreme scenarios to identify conditions that trigger further limitations.

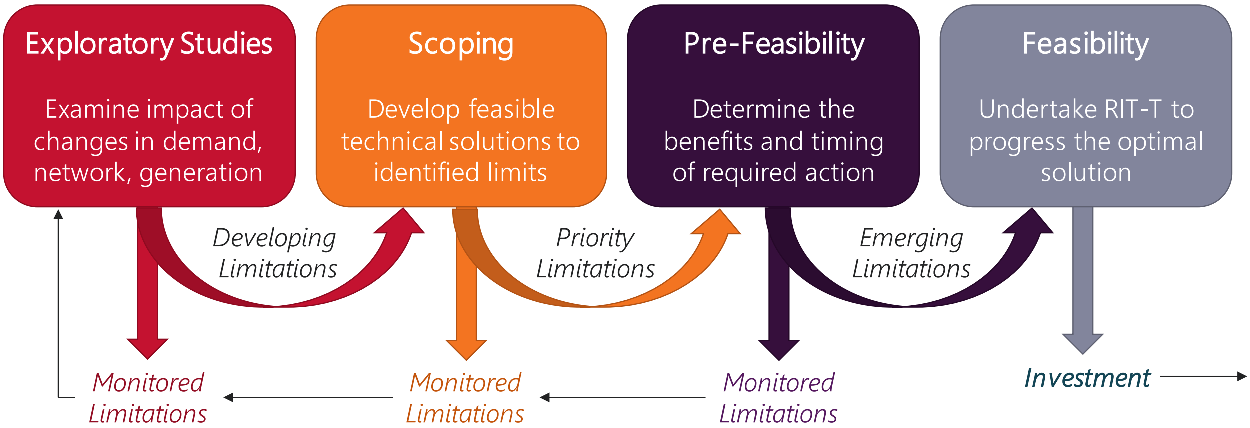
The VAPR analysis always incorporates a full set of state-wide screening studies, however specific trigger studies are undertaken when expected changes in generation, demand, or other planning inputs are likely to have a significant impact on the flow patterns and behaviour of the system.

Screening studies identify limitations by assessing network performance in terms of security and performance obligations under a range of different power system configurations. Security and performance obligations define the transmission system's technical limitations (for example, voltage ranges, stability limits, maximum fault currents, and fault clearance requirements). These obligations ensure that connected assets (and the power system itself) are designed to operate within known technical limits.

For each network element, screening studies are typically undertaken for a base case and a worst-case scenario, in order to capture a wide range of limitations. The worst-case scenario differs, depending on the transmission network element under consideration, and is a variation on the base case scenario designed to test that specific network element. For example, in a particular location the worst-case scenario may be 100% VRE generation output, while in another location the worst case may be 0% VRE.

AEMO identifies possible solution options to address the identified limitations, then estimates the costs of the solution options, and assesses the likelihood of these delivering positive net market benefits. Based on these assessments, the limitations are categorised as shown in Figure 30, and described below.

Figure 30 Identification of network limitations – the planning cycle



- **Emerging limitations** – limitations for which credible solutions are likely to deliver positive net market benefits, and where trigger conditions have been met. AEMO will begin a RIT-T (or other relevant regulatory approval process) within 12 months to identify the optimal solution and investment timing.
- **Priority limitations** – limitations for which credible solutions may deliver positive net market benefits. Following the VAPR publication, AEMO will undertake further pre-feasibility assessment using more detailed market modelling to assess the benefits from credible augmentation options.
- **Monitored limitations** – limitations for which there is currently no credible solution likely to deliver positive net market benefits. AEMO reassesses these limitations annually, when conditions change, or when a new credible solution becomes available.
- **Developing limitations** – a subset of monitored limitations, where triggering conditions may be met before the next VAPR cycle, where triggers may require further study, or where triggering conditions are more likely to change rapidly and therefore require heightened active monitoring. These may include limitations in areas of high investor interest, those related to step changes in supply or demand, or those which have occurred operationally under unusual system conditions.

AEMO performs high-level economic assessments in determining emerging limitations, and may perform these assessments for priority limitations when required. This analysis and categorisation can provide signals for potential non-network development opportunities, such as localised generation or demand response.

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 approach to transmission network limitation reviews.

4.2 Emerging limitations

Emerging limitations identified in past VAPRs

The following emerging network limitations were identified in the previous VAPR, and have now been addressed (or are progressing) through committed projects in the *Transmission Roadmap for Victoria*, as discussed in Chapter 3:

- Ballarat – Waubra – Ararat – Bulgana 220 kV line thermal limitation is addressed by a committed new 220 kV and 500 kV line. See Section 3.3.1 for more information.
- Greater Melbourne, Geelong, and south-west Victoria requirement to maintain voltages within operational limits during minimum demand periods is being addressed by committed additional reactors. See Section 3.3.2 for more information.
- South Morang – Dederang 330 kV line and South Morang 500/330 kV transformer thermal limitations are addressed by a committed new South Morang 500/330 kV transformer and South Morang – Dederang line uprating. See Section 3.3.3 for more information.
- Victorian export transient stability limitations, and export voltage stability limitations will be relieved by the committed South Morang 500/330kV transformer, and the committed new transmission lines in western Victoria. See Section 3.3.3 and Section 3.3.1 respectively. These limitations could be further addressed by Project EnergyConnect and the VNI West project. See Section 3.4.1 and Section 3.3.7 respectively.
- Victorian import voltage stability limitations are relieved by the recently secured NMAS contract for additional dynamic reactive power support (see Section 3.3), and could been further relieved by the committed SIPS project (see Section 3.3.6).
- Red Cliffs – Wemen – Kerang 200 kV line thermal limitation is addressed by a post-contingent generation fast tripping (GFT) scheme that was implemented in August 2020.

In the 2019 VAPR, AEMO identified that the high overloading of the Ballarat – Waubra 220 kV line for a credible contingency (Red Cliffs – Kiamal 220 kV line trip) may impact the network in the interim period before delivery of the Western Victoria augmentation (see Section 3.3.1). This constraint is the sixth most binding constraint, as shown in Table 9 in Section 2.6. AEMO is continuing to investigate the possibility of installing a post-contingent generation tripping scheme to address the Ballarat – Waubra 220kV line limitation.

New emerging network limitations

AEMO has conducted a combination of power flow modelling and economic assessments to identify new network limitations, following the methodology described in Section 4.1. These studies include all committed developments listed in Section 3.3.

No new emerging (direct to RIT-T) limitations have been identified since the 2019 VAPR, however four limitations have been reassessed as priority limitations, and an additional eight are now considered developing limitations worthy of further options analysis or investigation. These are discussed in the following sections.

4.3 Priority limitations

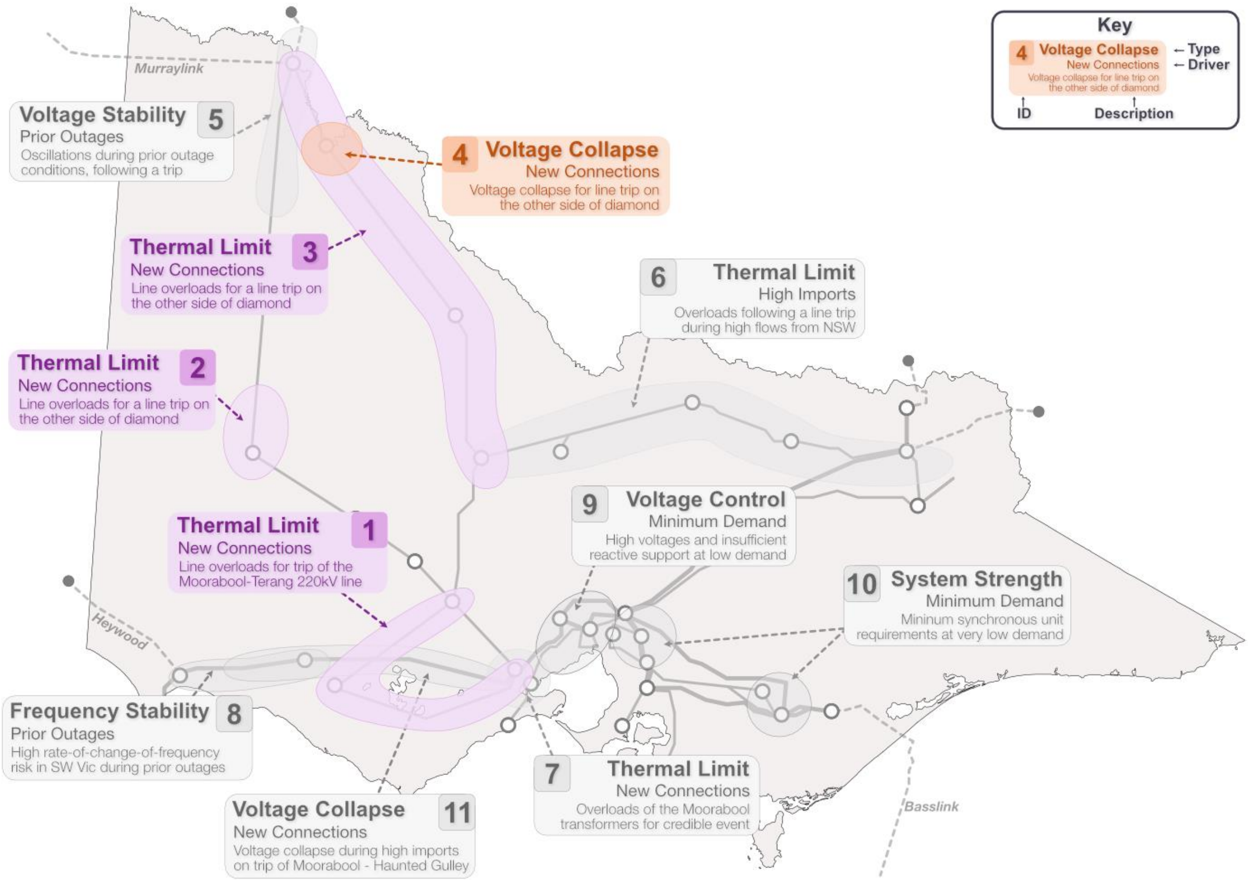
AEMO has identified limitations for which credible solutions may deliver positive net market benefits in the next 10 years. Following the VAPR, AEMO will undertake pre-feasibility assessments, including confirmation of the network limitation and assessment of benefits using more detailed market modelling.

All priority limitations in the 2020 VAPR are driven by new generation connections, and the first three of these four were identified previously as monitored limitations. The 2020 priority limitations comprise:

1. Overloading of the Ballarat – Terang – Moorabool 220 kV line for a credible contingency (trip of the Moorabool – Terang line), due to new connections. A NCIPAP project is in progress to alleviate this limitation from December 2020, and AEMO is investigating further post-contingent tripping schemes.
2. Overloading of the Horsham – Murra Warra 220 kV line for a credible contingency (trip of the Bendigo – Kerang line), due to new connections between Horsham and Kerang. AEMO is investigating the potential benefits of implementing a post contingent generation tripping scheme.
3. Overloading of the Red Cliffs – Wemen – Kerang – Bendigo 220 kV line for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line), due to new connections between Kiamal and Kerang. A NCIPAP project is in progress to alleviate this limitation from August 2021, and AEMO is investigating further post-contingent control schemes.
4. Voltage instability/collapse around Wemen Terminal Station for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line), due to new connections between Kiamal and Wemen. AEMO is investigating a low-cost post-contingent tripping scheme to alleviate this limitation.

Figure 31 presents these four priority limitations, and seven developing limitations (See Section 4.4). The drivers for these limitations are new connections, prior outage conditions, and minimum demand trends.

Figure 31 New priority limitations (coloured) and developing limitations under investigation (grey)



4.4 Developing limitations

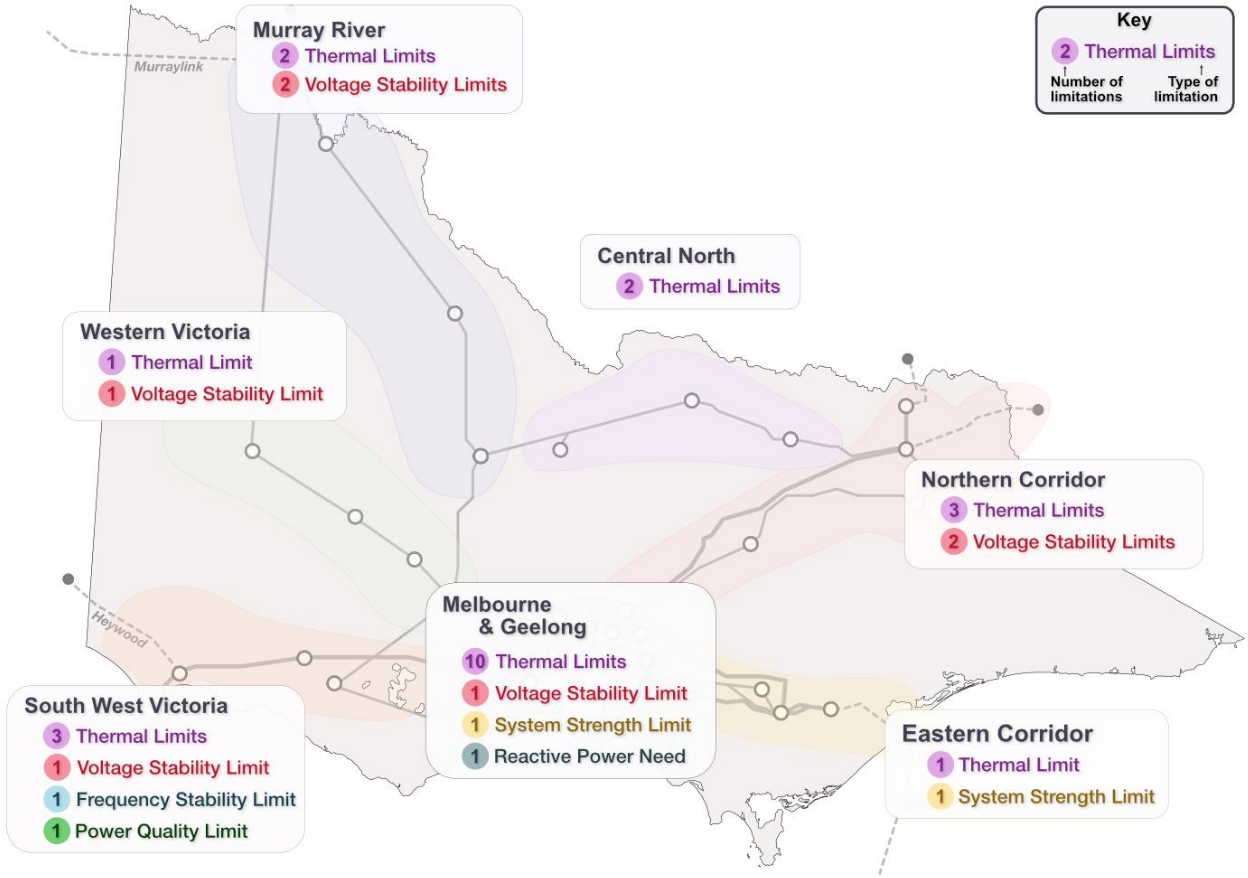
AEMO has identified the following developing limitations for which low cost solutions may be available, including control schemes and minor augmentation projects. The numbering used here aligns with the identifiers in Figure 31.

5. Voltage oscillation in western and north-western Victoria during prior outages for a credible contingency. This limitation was identified in the 2019 VAPR as a new monitored limitation. As shown in Table 8 in Section 2.6, this limitation was the top binding limitation over the period. This constraint bound frequently due to a number of network outages required to facilitate generator connection projects, including installation and testing of control schemes. AEMO will continue to closely monitor this limitation, and will investigate the use of a control scheme if the probability of such outages remains high.
6. Overloading of the Dederang – Glenrowan – Shepparton – Bendigo 220 kV line for a credible contingency (trip of one of the other Dederang – Glenrowan 220 kV lines), due to high New South Wales to Victoria imports. AEMO will consider the potential of implementing a post-contingent load shedding control scheme to enable the use of five-minute line ratings.
7. High overloading of the Moorabool 500/220 kV transformer for a credible contingency (tripping of the other Moorabool 500/220 kV transformer), due to new connections on the 500 kV lines west of Moorabool, which may require generators on these lines to be constrained. AEMO will consider the potential of implementing a post-contingent generation tripping scheme.
8. High ROCOF in South West Victoria constraining generators on the 500 kV lines west of Moorabool during prior outage of one of these lines, and for credible trip of another. AEMO will consider the potential benefits of implementing a post-contingent generation tripping scheme.
9. High voltages in Metropolitan Melbourne and South West Victoria caused by low demand conditions forecast by the 2020 ESOO, and possible withdrawal of a large load. AEMO is undertaking further analysis through the 2020 Network Support and Control Ancillary Services (NSCAS) review, and AEMO may trigger feasibility studies on additional reactive power investment when required.
10. Minimum fault level requirements at Thomastown and Loy Yang Terminal Stations caused by lower demand or potential early retirement of thermal generators. AEMO is undertaking further analysis through the 2020 *System Strength and Inertia Review*, to be published by the end of the year.
11. AEMO is investigating the potential of a new voltage collapse limitation in South West Victoria (tripping of the Moorabool – Haunted Gully 500 kV line), due to additional generator connections and under high import from South Australia. Detailed power system studies are underway, and if the limitation is confirmed, AEMO will assess any solutions with positive net market benefits.

4.5 Other monitored transmission network 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. A summary of the priority, developing and monitored transmission network limitations is shown geographically in Figure 32.

Figure 32 Summary of identified limitations by location (including priority, developing, and monitored)



The full list of Victorian transmission limitations can be found in Appendix A1. These limitations are not expected to carry significant impacts within the next five years, and are not currently economic to pursue. However, these may trigger further study if specific system changes or generator investment patterns occur.

For each of these limitations, AEMO will continue to monitor the identified trigger conditions and progress them to prefeasibility and feasibility studies when required. AEMO also welcomes feedback from stakeholders and non-network service providers, where they consider that credible options exist which would deliver positive net market benefits.

The following sections provide more detail on the VAPR's 2020 assessment of monitored limitations.

4.5.1 Thermal limitations

The emergence of new thermal limitations, and the benefits of addressing them, are heavily dependent on the geography and intermittency of both supply and demand. Patterns of network flow and asset utilisation are changing rapidly in Victoria, driven by strong investor interest in renewable generation projects, and strong consumer interest in distributed PV.

Many new generation projects are proposed in western parts of the state, where high-quality solar and wind resources are abundant. However, these parts of the network were not originally designed to support such high connection density, and a number of investors are are already facing economic and technical challenges associated with connecting to these weaker parts of the grid.

In the 2020 VAPR, AEMO has not identified any new thermal limitations that were not already identified in previous VAPR reports, or that are not currently being addressed by major transmission projects in the roadmap. However, this does not mean that all generator participants will be able to operate unconstrainted, particularly where these investments occur in remote parts of the grid or are outside the optimised investment plans that underpin the ISP and VAPR analysis.

Chapter 6 discusses how AEMO is adapting its planning processes to accommodate alternative generator build patterns and plan ahead for the types of limitations that might still emerge.

4.5.2 System strength limitations

As the System Strength Service Provider for Victoria, AEMO is required to remediate any system strength shortfalls when these are not otherwise required to be remediated by connecting generators themselves.

Declared and near-term shortfalls

On 13 December 2019, AEMO published a notice of fault level shortfall[85] at Red Cliffs Terminal Station and further revised this shortfall on 6 August 2020 due to updated projections of available fault levels[86]. The revised notice specified an immediate fault level shortfall (also referred to as a system strength gap) of at least 66 MVA, and which would continue beyond 2024-25 if not addressed. AEMO is addressing this shortfall through short and long-term activities, as outlined in Section 3.3.4.

Looking forward, under the Central scenario, the 2020 ISP[87] did not forecast any system strength shortfalls before 2025 at any of the other fault level nodes within Victoria.

Projected shortfalls

By 2035, the latest ISP studies forecast a potential 500 MVA shortfall at the Thomastown 220 kV node, and a potential 100 MVA shortfall at the Hazelwood 500 kV node. This follows the retirement of Yallourn Power Station between 2029 and 2032.

These results are compounded by recent reductions in the 2020 ESOO's minimum demand projections for Victoria, which indicate that the state may reach demand levels that would not support a minimum number of synchronous units online without constraining off non-synchronous generation.

If the Yallourn retirement were to occur earlier, or the Victorian region operational demand were to reduce significantly, then the need for new system strength remediation may be brought forward. This will be further reviewed as a part of the 2020 *System Strength and Inertia Review*, and AEMO has classified this as a developing limitation for heightened monitoring, options analysis, and investigation.

Minimum synchronous unit requirements

Given rapid increases in renewable generation, coupled with falling minimum demands, there are likely to be times over the coming decade where surplus generation is available that cannot be exported across the interconnectors, resulting in units being decommitted (below their minimum stable generation levels), or spilled wind and solar resources.

At these times, the units with the highest bid prices will generally have their output reduced first. However, the Victorian region also has a requirement to maintain a minimum number of synchronous units online for system strength purposes[88]. There are currently 34 combinations of synchronous units that meet this requirement, and at current demand levels it is rare that this limit becomes binding (see Section 2.5.2).

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[85] AEMO, *Notice of Victorian Fault Level shortfall at Red Cliffs*, December 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice_of_Victorian_Fault_Level_Shortfall_at_Red_Cliffs.pdf.

[86] AEMO, *Notice of Change to System Strength Requirement and Shortfall at Red Cliffs*, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en&hash=5C3EDDABDF81891B3989F6FF0466C486.

[87] AEMO 2020 ISP Appendix 7, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[88] AEMO, *Transfer Limit Advice – System Strength*, July 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

If pre-dispatch analysis indicates that these minimums are unlikely to be met, either pre-contingent or within 30 minutes following a credible contingency, the System Operator may direct an appropriate synchronous generator to come online. In the last year, this happened in Victoria on one occasion[89].

As minimum demands fall in future, it may become increasingly difficult to maintain this minimum requirement – particularly at times of high renewable generation availability where synchronous units will begin to be displaced from the dispatch stack. At these times, renewable generation output may need to be reduced to ensure system strength requirements are met. South Australia has encountered similar issues over the last three years, with synchronous generating units being directed online, and ElectraNet is progressing a remediation project to install additional synchronous condensers to address this issue[90].

AEMO carried out a case study with a simplified economic analysis to identify the indicative market impact of renewable generation curtailment due to system strength and interconnector limitations. This analysis used the 2020 ESOO demand forecasts, indicative solar and wind profiles, existing and committed generation capacity, 1,000 MW of minimum synchronous generation, and 1,000 MW interconnector capability.

The study analysed each year until 2026, and indicated a maximum of 2.9 GW of renewable generation may be curtailed during periods towards the end of this study horizon. Table 16 presents this at annual resolution.

Table 16 Impact of VRE curtailment due to system strength and export limitations

Financial Year	MWh constrained	Maximum MW constrained	Hours constrained	Indicative redispatch costs
2021	22,151	1098	47	$277,244
2022	56,219	1591	119	$703,631
2023	93,461	1835	182	$1,169,735
2024	172,556	2239	290	$2,159,678
2025	267,787	2783	401	$3,351,570
2026	358,273	2936	494	$4,484,078
Total/maximum	**970,448**	**2936**	**1,531**	**$12,145,936**

These results carried an indicative market redispatch cost of approximately $12 million across the six-year period. With this indicative market impact, AEMO does not expect major augmentation is likely to be justified, beyond those already being delivered through the VNI Upgrade (Section 3.3.3) and the VNI West RIT-T (Section 3.3.7). AEMO will continue to closely monitor this limitation.

AEMO will continue to monitor how actual demand and operating conditions are tracking against forecast, while exploring alternative technology solutions to system strength issues. Further analysis is underway through AEMO's 2020 *System Strength and Inertia Review*, to be published by the end of the year.

Future REZ system strength requirements (driven by generation investment)

Each new connecting generator is required to implement or fund system strength remediation, such that its own connection does not have an adverse impact on the overall system strength requirements of the network. This means that in some locations, the connection proponent will be required to demonstrate system strength remediation is in place before connection approvals can be granted.

The 2020 ISP calculates the available fault level in each Victorian REZ, and the approximate system strength remediation that would be required by proponents under forecast (optimal) generator build patterns. The modelling assumed that local generators coordinate their investments to lower overall remediation costs.

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[89] See Market Notice 70102, 70103, 70119 and 70143 at https://aemo.com.au/en/market-notices.

[90] See https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

The results of this analysis are shown in Table 17, and indicate that:

- All REZs are at or near their system strength limits, except the Ovens Murray and Gippsland zones.
- There is a forecast deficit in the Western Victoria REZ of 1,350 MVA by 2029-30, and a potential need for system strength remediation works by proponents as soon as 2025-26 under the Central scenario.
- There is a forecast deficit in the South West Victoria REZ of 1,900 MVA by 2029-30, and a potential need for system strength remediation by proponents as soon as 2026-27 under the Central scenario.
- There is a forecast deficit in the Central North Victoria REZ of 500 MVA by 2029-30, and a potential need for system strength remediation works by proponents as early as 2028-29 under the Central scenario.

Table 17 System strength remediation requirements under 2020 ISP Central scenario

REZ	Available fault level: existing (MVA)	Available fault level: 2029-30 (MVA)	System remediation requirement	Forecast date	Cost
Ovens Murray	900	950	Remediation not required with forecast VRE.	N/A	N/A
Murray River	At limit	200	Remediation not required with forecast VRE.	N/A	N/A
Western Victoria	At limit	-1,350	1 x 250 MVAr synchronous condenser.	2025-26	$45M to $60M
South West Victoria	At limit	-1,900	1 x 250 MVAr synchronous condenser.	2026-27	$45M to $60M
Gippsland	4,850	2,950	Remediation not required with forecast VRE.	N/A	N/A
Central North	250	-500	1 x 125 MVAr synchronous condenser.	2028-29	$40M to $55M

Note: The actual timing and size of fault level deficits will depend on future generator connections. The numbers in this table are indicative only, and are based on a modelled (optimal) generator expansion plan. Remediation estimates for additional ISP scenarios, and other REZ information of relevance to proponents, are in AEMO's REZ Scorecards in Appendix 5 of the 2020 ISP.

The AEMC is currently investigating the system strength framework and its associated Rules[91,92].

4.5.3 Inertia limitations

Power systems with high inertia can resist large changes in system frequency arising from contingency events that create an imbalance between supply and demand.

With the increase in DER and non-synchronous renewable generation, system inertia is likely to decrease, making it more difficult to manage power system frequency events. Under the NER (and in accordance with the published Inertia Requirements Methodology[93]) the satisfactory and secure requirements for synchronous inertia are identified for each NEM region under islanded operating conditions. As the Inertia Service Provider for Victoria, AEMO is required to remediate any inertia shortfall identified.

The 2020 ISP assesses the available inertia in Victoria[94], and finds that a completely islanded Victorian region could fall below the minimum threshold for substantial periods across the study horizon. By 2029-30, this could be as much as 10% of the year, as shown in Figure 33.

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[91] See https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[92] See https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem.

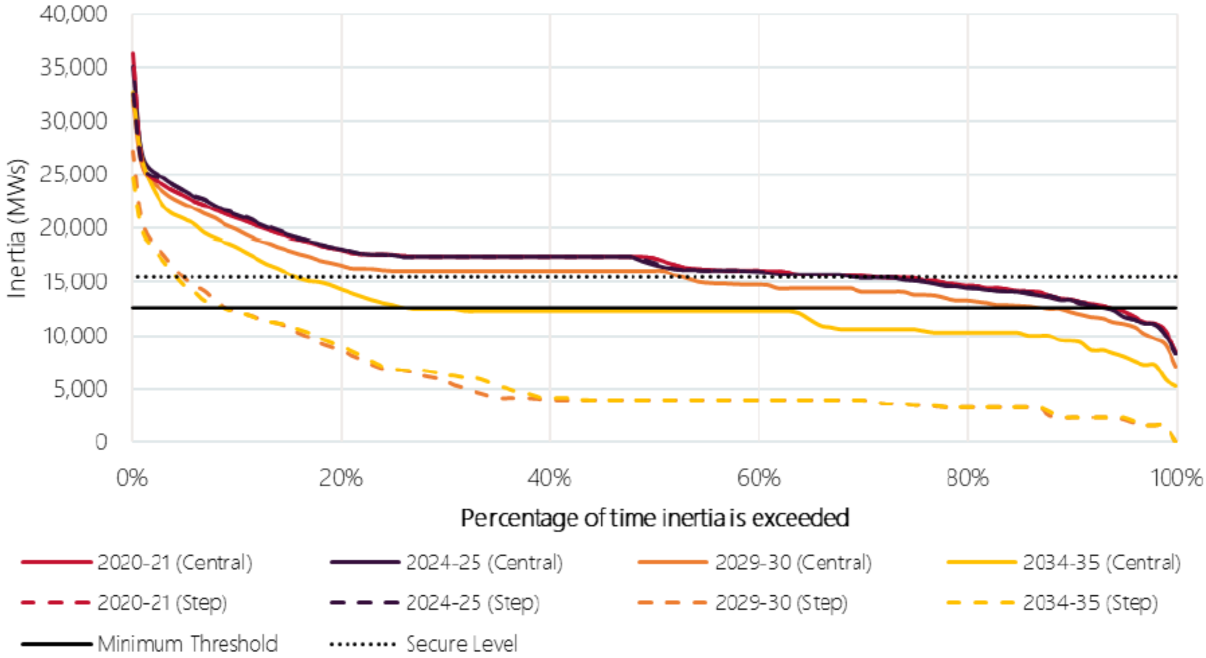
[93] AEMO, *Inertia Requirements Methodology Inertia Requirements and Shortfalls*, June 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[94] AEMO, 2020 ISP Appendix 7 System Strength Outlook, July 2020, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

These results are further compounded once the Yallourn Power Station retires between 2029 and 2032, resulting in forecast islanded inertia below the threshold for almost 40% of the time.

However, Victoria's strong interconnection with neighbouring regions makes islanded operation less likely than for other regions, and no inertia shortfalls are currently projected ahead of generator closures in the Latrobe Valley. However, following several partial islanding events since the 2019 VAPR, AEMO is investigating further through its 2020 *System Strength and Inertia Review*. The VNI West project is likely to further strengthen interconnection and reduce Victorian inertia risks late in the decade.

Figure 33 Projected inertia in Victoria, under 2020 ISP Central and Step Change scenarios



4.5.4 Voltage limitations

The 2019 NSCAS report[95] did not identify any NSCAS gaps related to voltage limitations in the Victorian region. However, it did identify a range of potential issues for closer monitoring. The VAPR has undertaken further review, with the results presented below.

High voltages in Metropolitan Melbourne and South West Victoria

The Victorian DSN experiences high voltages during minimum demand conditions, particularly in the Metropolitan Melbourne area and the south-west transmission corridor. AEMO currently manages this operationally via temporary network reconfigurations and a NMAS contract for reactive services. The historical use of these measures is described in Section 2.5.2. AEMO has now completed a RIT-T for a long-term remediation investment in additional reactive plant by 2022 (see Section 3.3.2).

The 2020 ESOO forecasts further and sharper declines in minimum demand than previously anticipated. This will act to increase the benefits of delivering this project. The forecasts may also signal the need for further investment in the late 2020s, and AEMO will continue to monitor actual demand trends against demand forecasts.

Additionally, as the Latrobe Valley thermal generating units age or withdraw, their availability and reliability to provide full reactive power capability may reduce due to increased maintenance or periods of unavailability.

[95] AEMO, December 2019, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2019/2019_nscas_report.pdf?la=en&hash=B34E0CAEF3256790E262F22902C8FCB0.

This further limits sources of voltage control during low demand periods, particularly as these often align with the mostly likely periods of generator maintenance and outages.

Initial analysis shows that by the end of the decade, there may be a need for up to an additional 150-600 MVAr of reactive absorption capability. Some of this may be met by the reactive capability of newly connecting generators, or by further network investment projects. AEMO has classified this as an developing limitation for further investigation, and will continue to track demand and voltage trends against forecasts.

The 2020 ESOO also forecasts negative demands in Victoria from 2028-29, which will drive further changes to the network and AEMO's planning approach. This is discussed further in Section 6.4.2.

High voltages in the north-west of Victoria

Recently, high voltages in the north-west of Victoria have been observed during low demand periods when the 220 kV transmission lines are lightly loaded. These have mostly occurred during planned outages of other 220 kV lines or the Murraylink interconnector. AEMO has investigated the possibly of high voltages being experienced under system normal conditions, but find this unlikely due to existing reactive plant in the area.

AusNet Services has identified that the Horsham static Var compensator (SVC) is reaching the end of its serviceable life, and has included replacement of this asset in its current asset replacement plans. AEMO reviewed these plans as part of the 2020 VAPR process, and confirmed an ongoing need for this asset (see Chapter 5). AusNet Services initiated a replacement RIT-T for the Horsham SVC in June 2020[96].

Some wind farms and solar farms in the north-west of Victorian have internal reactive power equipment installed to meet their agreed performance standards. However, not all of this equipment is visible to AEMO's System Operations team, and therefore may not be available for use in managing system reliability and security. AEMO, in its operational capacity, will continue working collaboratively with intending and registered participants to explore avenues of incorporating new reactive equipment into AEMO's real time operation systems. This work aims to ensure that any available, but underutilised, reactive support can be made available to the System Operator when needed.

High voltages around the Eildon Power Station area

During periods of low demand and low power transfer, high voltages are experienced in the DSN around Eildon Power Station (EPS). This high voltage issue has been successfully managed by operational measures and AEMO has not identified a need for any further network or non-network investment to address these issues in the near-term future.

4.5.5 Credible contingency size

Operation of control schemes following a network disturbance

Several large credible contingencies have been identified in areas where multiple renewable generators disconnect or runback simultaneously due to special protection schemes following a network trip. During times of high wind generation in Victoria, the runback or disconnection of these units could represent a significant loss of generation, and could become Victoria's largest single generator contingency event.

For example, on trip of the Ballarat to Waubra to Ararat 220 kV line, a control scheme is in place that would result in disconnection of the Ararat, Crowlands, Bulgana, Murra Warra, and Waubra wind farms. The maximum output of these generators is 840 MW, and therefore this credible contingency would exceed the current largest supply contingency (represented by Loy Yang or Basslink at up to 600 MW).

New operational measures, such as restricting generation from the relevant generators pre-contingent, have been implemented to manage the voltage stability and frequency control limitations as a result.

Once the Western Victoria Transmission Network project is complete, the size of the largest single generation contingency event could be reduced, as Waubra Wind Farm will be transferred to one of the newly

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[96] See https://www.ausnetservices.com.au/-/media/Files/AusNet/projects/Horsham-Static-Var-Compensator-PSCR.ashx?la=en.

constructed lines and would not be tripped with other wind farms. AEMO has commenced a review of the control schemes in western Victoria to accommodate delivery of the Western Victoria Transmission Network Project.

DER reduction following a network disturbance

The trip of DER caused by undervoltage following a network disturbance is an area of ongoing study in both the operational and planning timeframe. The potential net contingency size due to DER and load reduction following a voltage disturbance is estimated to be as high as 560 MW by 2022, compounded by the size of the original contingency event. AEMO is continuing to investigate and monitor this issue, and Section 6.4.3 provides more information.

4.5.6 Retirement of large industrial load

AEMO has undertaken a number of sensitivity studies relating to any potential closure of the APD smelter in South West Victoria. While no retirement decisions have been announced by the plant, it is important to understand the impacts such a future decision may have on network operations and planning. AEMO has also assessed the impact of a large generation plant closure on network asset utilisation (see Section 5.4).

With the retirement of a large industrial load such as the 500 MW smelter, the Victorian daily demand profile would be offset downwards by the size of the plant, resulting in a reduction in both maximum and minimum regional demand by the same amount. The effects of this on the DSN could be both positive and negative.

Maximum demand implications

A substantial (500 MW) reduction in maximum demand would:

- Improve the system's ability to maintain reliability during summer and therefore reduce the likelihood of activating emergency reserves or shedding load.
- Reduce the state's reliance on imports from other regions, and particularly across the VNI, which is often constrained at high temperatures due to both thermal and voltage stability limitations. This may reduce the need for additional interconnector control schemes and network investment targeted at making interregional supplies available.

Minimum demand implications

A substantial reduction in minimum demand would:

- Further exacerbate the high voltage issues seen in Victoria during low demand periods. AEMO has considered the possibility of such large industrial load retirement when sizing the solution to its recent reactive power RIT-T project (see Section 3.3.2), however such a retirement may accelerate the need for further reactive plant.
- Accelerate the need for operator intervention or network investment to meet state-wide system strength requirements, by putting downward pressure on the number of synchronous units online at any one time.
- Increase Victorian exports, and potentially allow other states to access additional low-cost renewables from the southern states (this likely applies at all times, not just minimum demand).

Security implications

A substantial reduction in industrial demand in south-west Victoria would also:

- Introduce new thermal and stability constraints on existing and future generation connected to the 500 kV network in the south western corridor. In particular, this generation would need to be transferred further to meet load, and may face greater thermal competition with imports from South Australia.
- Reduce the size of several credible contingency events (and the associated constraints this introduces). For example, currently a trip of the APD smelter in response to a 500 kV line contingency is one of the most significant credible contingency events in the state, and is the primary factor in a number of Victorian

constraint equations – particularly the voltage stability export limit, for example the V^^N_NIL_1 and V^^N_HWSM_xxx constraint equations. As shown in Table 10 in Section 2.6, these constraints ranked fifth and tenth respectively for binding impact since the previous VAPR.

- Improve the reliability and security of the Heywood interconnector, where a control scheme is currently used to manage voltage stability and frequency for loss of both 500 kV lines west of Moorabool. This control scheme isolates South Australia from Victoria rather than needing to supply the smelter load from across the border. Without this scheme, parts of South Australia would be more prone to voltage instability, possibly leading to load shedding. Without this load, the control scheme would no longer be required, and the probability of a Victoria – South Australia separation event would be reduced.

4.6 Power System Frequency Risk Review (PSFRR)

The PSFRR is a national and periodic review of power system frequency risks associated with non-credible contingency events in the NEM. AEMO undertakes this review nationally in consultation with each of the TNSPs. The review considers:

- Non-credible contingency events which AEMO expects could likely involve uncontrolled frequency changes leading to cascading outages or major supply disruptions.
- Current arrangements for managing such non-credible contingency events.
- Options for future management of such events.
- The performance of existing Emergency Frequency Control Schemes (EFCSs).

The 2020 PSFRR process is currently underway through a staged approach, and the Stage 1 report proposed declaration of a new protected event for the non-credible separation of Victoria and South Australia. This event would cover trip of the 500 kV circuits between Heywood and Moorabool substations, resulting in trip of the Heywood interconnector. Declaration of this non-credible event as a protected event would initially allow Heywood interconnector flows to be limited during periods when the under-frequency load shedding schemes in South Australia were not sufficient to prevent a cascade failure should the event occur.

Further information on the PSFRR process, stages, and next steps are available on the AEMO website[97].

4.7 Victorian control schemes

As proposed in the 2019 VAPR, AEMO has now reviewed all existing system protection and control schemes that were in operation across the Victorian DSN before 2019. Through this process, AEMO has identified a number of control schemes that warrant variations to accommodate recent changes in local operating conditions and network configurations. AEMO will implement these modifications as soon as practicable.

AEMO has also begun a review of the control schemes required after commissioning of the Western Victorian Transmission Network RIT-T, with a view to scheme designs that will maximise the allowable output of renewable generation along the path of that network augmentation.

4.8 Distribution planning

AEMO reviews DNSP plans for existing and new connection points and, where relevant, incorporates the impact of any distribution network modifications in its transmission planning work. AEMO and the DNSPs work together to resolve connection asset limitations, and this cooperation 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 2019 Transmission Connection Planning Report, prepared by the Victorian DNSPs.

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[97] See: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-frequency-risk-review.

5. DSN asset replacement and retirement

This chapter addresses NER requirements related to DSN asset retirement, deratings, and replacement.

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 2019-20, AEMO again worked closely with AusNet Services to assess the need for the replacement, refurbishment, derating, or retirement of existing assets that are approaching end-of-life.

In the 2020 VAPR:

- AusNet Services' 2020 asset replacement and refurbishment plans are largely consistent with those presented in the 2019 VAPR.
- Several new asset replacement projects have been identified, or have now moved within the assessment horizon, including:
  - Circuit breaker replacement at the Keilor, Rowville, Fisherman bend, Moorabool and Thomastown associated with the 66 kV and 220 kV reactive plants.
  - Circuit breaker replacement at the Thomastown terminal station.
  - Bendigo-Kerang 220 kV Transmission line replacement.
- 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 impact of future generation plant withdrawals on existing asset in the Latrobe Valley. This is important because, although the traditional focus of network planning has been to support growing supply and demand conditions, 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 5.12.2, regional transmission annual planning reports 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[98].

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 provide information about the planning process for asset retirement, replacement, refurbishment, and deratings.

5.2 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 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.
- AEMO undertook a desktop 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 also 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.

5.3 Needs assessment results

Table 18 presents the summarised findings from the assets needs assessment. Several new assessments were conducted as part of the VAPR 2020, including:

- Circuit breaker replacement at the Keilor, Rowville, Fisherman bend, Moorabool and Thomastown associated with the 66 kV and 220 kV reactive plants.
- Circuit breaker replacement at the Thomastown Terminal Station.
- Bendigo-Kerang 220 kV transmission line replacement.

[98] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

Table 18 Network need assessment results

Project name	Location	Total cost (real $M)	Target completion date	Major assets components	Retirement outcome
Horsham SVC Controls and Protection Replacement	Horsham	45	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	Moorabool	19	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 doublebreaker 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
				Moorabool – Ballarat 220kV No. 2 Line double breaker switch bay	Western Victorian generation constrained and reduced reliability

Project name	Location	Total cost (real $M)	Target completion date	Major assets components	Retirement outcome
South Morang 330/220 kV Transformer Replacement – Stage 2 (One 700 MVA 330/220 kV transformer)	South Morang	44	2024	South Morang 330/220 kV H1 transformer	Reduced reliability and capability to meet peak demand
Sydenham 500 kV GIS Replacement	Sydenham	66	2024	Sydenham – Moorabool 500kV No.1/No.2 Lines breaker-and-half switch bay	Reduced reliability caused by system separation due to a single credible contingency and reduction in interconnector capabilities
				Sydenham – South Morang 500kV No.1/No.2 Lines breaker-and-half switch bay	Reduced interconnector and Western Vic Renewable Integration capabilities
				Sydenham – Keilor 500kV Line breaker-and-half switch bay	Reduced reliability and capability to meet peak demand. Reduced interconnector capabilities
Thomastown Circuit Breaker Replacement (New in 2020 VAPR)	Thomastown	14	2024	Thomastown No.1 Capacitor bank circuit breaker	May reduce maximum supportable demand caused by reduced reactive power margin if major new generation relies on Latrobe Valley-Melbourne 500kV transmission [A]
South Morang 500 kV GIS Replacement – Stage 1	South Morang	18	2024	South Morang – Hazelwood 500kV No.1 Line breaker-and-half switch bay	Reduced reliability and interconnector capabilities
				South Morang – Sydenham 500kV No.1 Line breaker-and-half switch bay	Reduced interconnector capabilities
Reactive plant 66 and 220 kV Circuit Breakers replacements (New in 2020 VAPR)	Keilor, Rowville, Fishermans bend, Moorabool and Thomastown	7	2025	Keilor, Rowville, Fishermans bend, Moorabool and Thomastown various 66kV and 220kV capacitor bank circuit breakers	May reduce maximum supportable demand caused by reduced reactive power margin if major new generation relies on LV-Melbourne 500kV transmission [A]
Bendigo – Kerang 220 kV transmission line replacement (New in 2020 VAPR)	Bendigo-Kerang	204	2028	Bendigo-Kerang 220 kV transmission line	Western Victorian and South Western NEW SOUTH WALES generation constrained and reduced reliability (also potentially during line replacement), unless VNI West (Kerang Route) early development occurs

Project name	Location	Total cost (real $M)	Target completion date	Major assets components	Retirement outcome
Loy Yang Power Station and Hazelwood 500 kV Circuit Breaker Replacement Stage 2 (14 circuit breakers)	Loy Yang PS and Hazelwood	84	2029	Loy Yang – Hazelwood 500 kV No. 1 line double breaker switch bay	Generation constraints and reduced reliability
				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

A. In addition to maximum supportable demand, AEMO also assessed the impact of in-service 220 kV or 66 kV cap banks on Victorian import voltage stability limits and voltage control. Preliminary results indicated that retiring any existing capacitor bank could reduce the Victorian import voltage stability limit from New South Wales, however not all capacitor banks are required to be in-service at the same time for voltage control. Further studies using a voltage stability assessment tool (VSAT) would be required to confirm the preliminary result on the impact of Victorian import voltage stability limit. The retirement impacts of capacitor bank circuit breakers and their associated capacitor banks are inter-dependent.

5.4 Latrobe Valley asset utilisation sensitivities

The changing generation mix in Victoria continues to impact 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, the utilisation of existing assets will continue to change, impacting the economic signals for existing asset replacement, refurbishment, derating, and retirement.

These impacts are not simple to project; for example:

- Retirement of further coal-fired generation in the Latrobe Valley would decrease local asset utilisation.
- 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 key network and supply change scenarios. Further power system and market modelling analysis would be required to quantify the implications for asset replacement planning.

5.4.1 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[99]. This information was last updated on 22 July 2020, and indicates an expected closure profile for Yallourn Power Station between 2029 and 2032, and for Loy Yang Power Station between 2047 and 2048.

AEMO has assessed at a high level the asset utilisation impacts of a full Yallourn Power Station retirement on the existing power system with committed projects included, and during a high-demand snapshot. The modelling methodology and key findings are presented in this section below.

- 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; however, also provide opportunities for new generation or interconnection projects to take advantage of existing infrastructure.

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[99] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/generating-unit-expected-closure-year.xlsb?la=en.

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 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 conducted for the 2019 VAPR indicated 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.

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 conducted for the 2019 VAPR projected:

- 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.

Retirement of a Loy Yang generator unit

Power flow studies conducted for the 2019 VAPR indicated that the retirement of a Loy Yang generator unit would not be 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

Power system studies conducted previously suggest that 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.

5.4.2 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 as part of VAPR 2019 studies:

- Case 1 – Yallourn Power Station remains in service.
- Case 2 – Yallourn Power Station retires, the Latrobe Valley 500 kV and 220 kV networks operate radially.
- Case 3 – Yallourn Power Station retires, 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 34 shows that under case 2, the ROTS A1 transformer is projected to overload more than 20% of the year.

Figure 34 ROTS A1 Transformer load duration curve

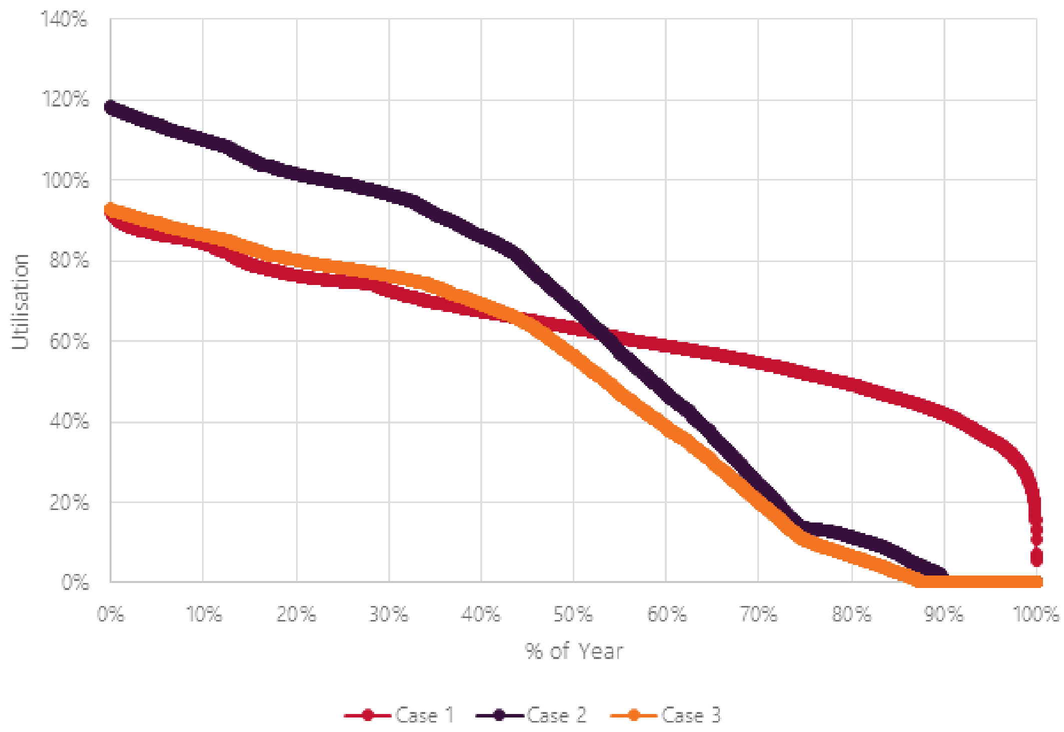


Figure 35 shows that the SMTS H2 transformer is projected to overload more than 20% of the year under case 2. Under case 2 assumptions, the utilisation of the HWTS transformers is projected to be low. However, other assets would be overloaded under system normal.

Figure 35 SMTS H2 Transformer load duration curve

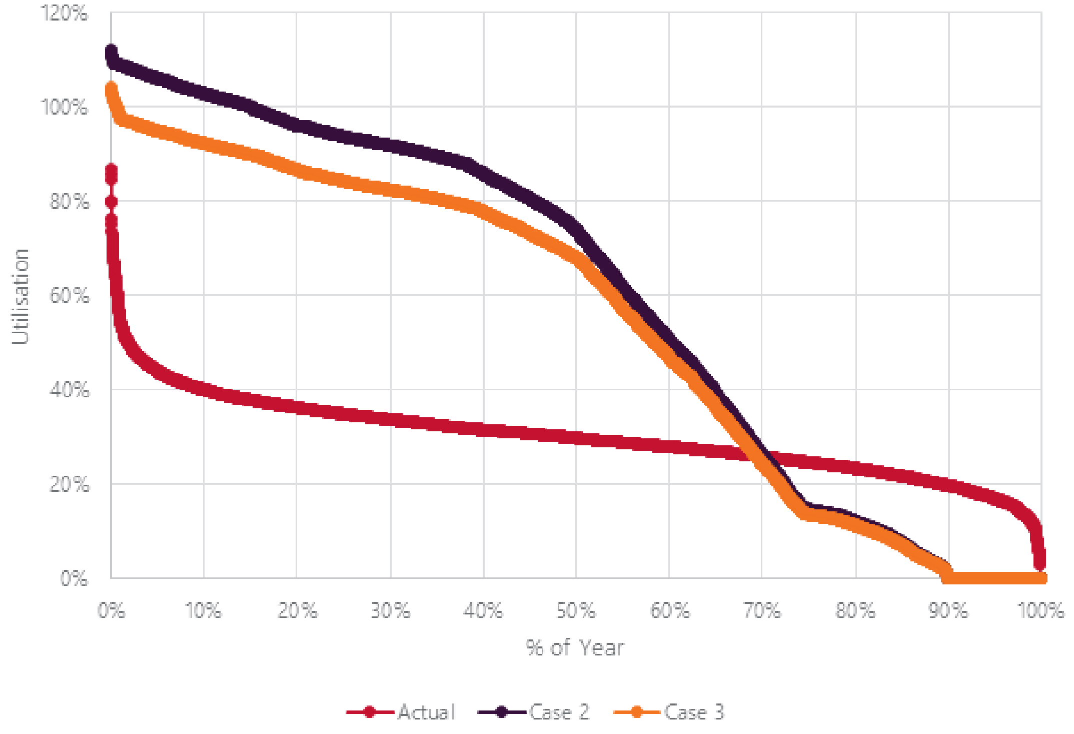
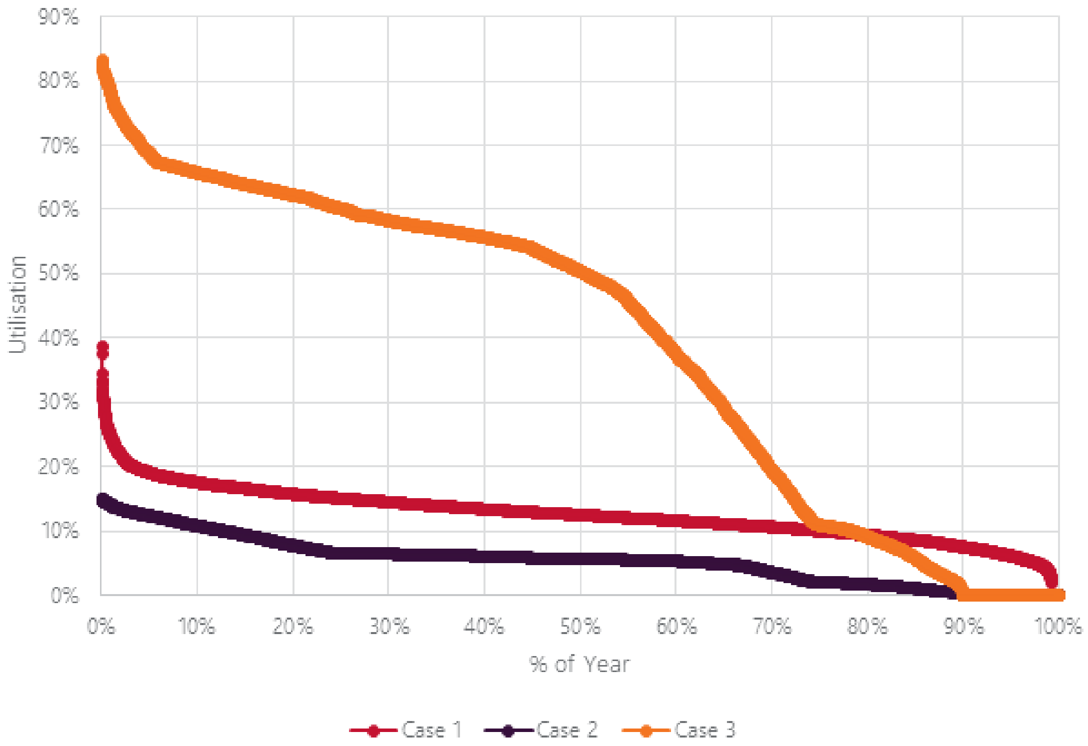


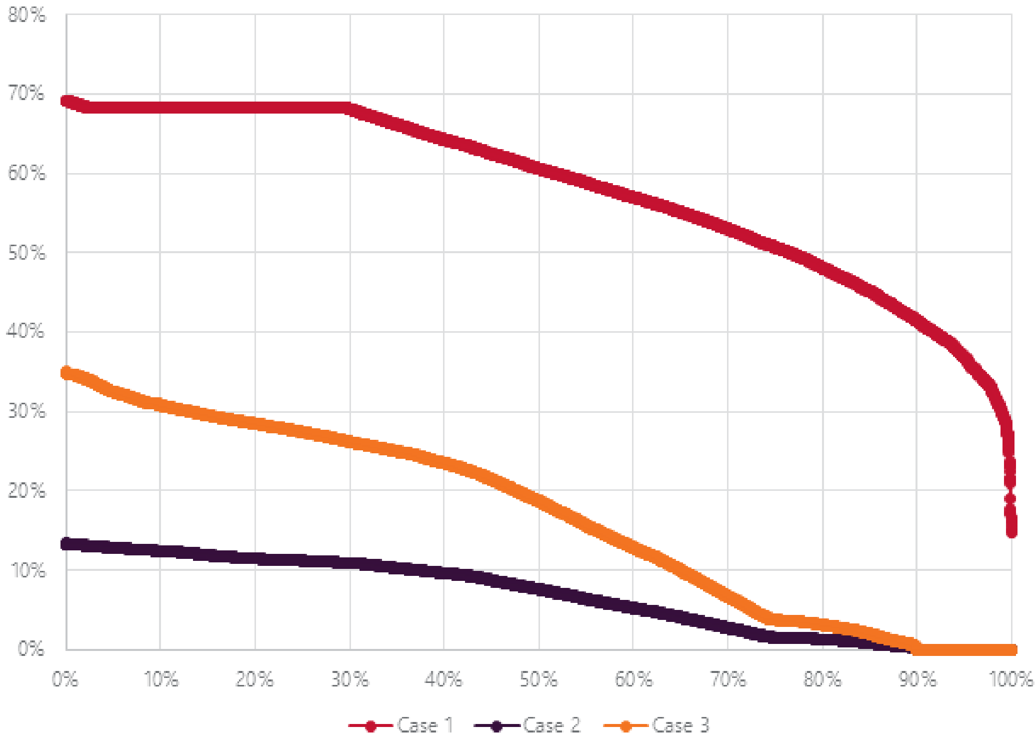
Figure 36 shows that under case 3 assumptions, the utilisation of the HWTS transformers could increase to up to 85%. As indicated in the previous two figures, any overloading of the ROTS A1 Transformer and SMTS H2 Transformer would likely be removed with this network configuration.

Figure 36 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 37. Even under case 3, with the 500 kV and 220 kV networks paralleled, utilisation is projected to remain below 40%.

Figure 37 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, 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. Adapting to the future network

This chapter explores the ways AEMO is adapting its transmission planning approach to keep pace with emerging trends in technology, geography, and demand.

Planning beyond the current roadmap

AEMO's *Transmission Roadmap for Victoria* (Chapter 3) includes all projects that will deliver system requirements and legislated policy targets in the least-cost way, as prescribed under the current regulatory framework. However, there continues to be strong developer interest beyond the least-cost expansion plan, often driven by locations with excellent renewable resources. As a result, it is likely that new generator investment will continue to test the system's capabilities in weaker parts of the network, and new system constraints could emerge that result in delays to the connection process, or curtail the output of some renewable generators.

The current regulatory framework assigns these risks directly to individual generators and developers as 'locational signals' that should encourage investment in more optimal locations from a network perspective. Experience to date has shown that these signals are not always sufficient to guide investments.

The long lead times associated with delivering transmission infrastructure can also result in extended generator constraints when imbalances between network and generation investment emerge. This could lead to less efficient utilisation of the state's renewable resources, or higher risk premiums that could be passed through into electricity market prices.

To proactively address these issues, AEMO believes it is prudent to begin pre-feasibility assessments on potential system improvement projects that would strengthen those areas with high developer interest, even before formal trigger conditions have been met. To this end, in parallel with the VAPR, AEMO has commenced a *REZ Development Plan* study, which it aims to publish in mid-2021.

The *REZ Development Plan* study will seek to understand how continued renewable investment, especially in areas with high quality resources, could impact the required transmission build for Victoria. It will identify projects that could progress through the regulatory process if justified, or that could be available for third-party investment outside of the existing regulatory framework. The monitored limitations described in the previous chapter may form the basis of triggered projects in the *REZ Development Plan*.

Continuing to adapt

The VAPR and *REZ Development Plan* together form the cornerstone of AEMO's strategy to provide a resilient Victorian system that delivers lower-cost outcomes for consumers. AEMO is continuing to adapt its regional planning processes to keep pace with Victoria's dynamic regulatory, environmental, operational, technological, policy changes and investment drivers.

AEMO has initiated a connections uplift program that will place greater emphasis on clear communication, transparent process, common methodologies, and improved account management.

The large-scale deployment of inverter-based generation in weak parts of the network has pushed the system into previously uncharted territory, and requires AEMO to conduct detailed Electromagnetic Transient (EMT) studies to identify and address potential system issues. EMT modelling is now an essential part of most connection studies, and is becoming increasingly necessary for mid-term planning. AEMO has continued to develop and benchmark its multi-region wide-area models, and is working to build-out its internal modelling infrastructure and expertise.

To help proponents adapt to these increasing modelling requirements, AEMO is developing an industry modelling platform that would provide access to a detailed EMT simulation environment while also protecting confidential information contained in many of the generator models. This new platform aims to provide connection applicants with the ability to design, tune and validate their own plant models ahead of (or in parallel with) the connections process.

In network planning, a trend towards high DER and negative minimum demands will present unprecedented challenges. AEMO is progressing a number of recommendations from the Renewable Integration Study, with a focus on the need for forward-looking performance standards, the controllability of distribution-connected supplies, and the need for new analysis capabilities to assess system performance under a range of emerging reactive, system strength, and reverse power flow conditions.

Many of these challenges cannot be resolved by traditional solutions, and AEMO looks forward to working closely with industry to identify new ways of solving the issues identified in this report, maximise the use of emerging technologies, and promote the use of non-network options where this is possible and economic.

6.1 Introduction

As the system changes, AEMO must continue to adapt its regional planning processes to keep pace. These adaptations are occurring across a spectrum of challenging issues, in particular:

- **Adapting to the changing supply mix** – ensuring planning and regulatory approval processes are agile and fit-for-purpose to deliver a network that supports both generation and market customers.
- **Adapting to changing connection needs** – ensuring connection processes and modelling activities provide clear communication channels, transparent milestones, and personal account management.
- **Adapting to new operational challenges** – ensuring the planning function delivers a resilient and diverse network that can be operated into the future, despite emerging changing characteristics.
- **Adapting to new technologies** – ensuring emerging technologies are fully understood and given even-handed consideration alongside network options in all planning processes.

The following sections explore each of these categories in more detail, and identify several initiatives and activities AEMO is undertaking in each category.

6.2 Adapting to the changing supply mix

AEMO's transmission roadmap of committed and future projects (see Chapter 3) has been designed to efficiently deliver government policy objectives, while meeting system security requirements, and minimising cost to consumers. However, the inherent uncertainties in long-term planning mean that new network needs can still emerge.

Patterns of network flow and asset utilisation are changing rapidly in response to strong investor interest in renewable generation projects, and strong consumer interest in distributed PV. Section 3.2 presents an overview of renewable energy interest in Victoria, noting significant growth in both existing and projected levels of renewable generation.

Many of these new projects are proposed in western parts of the state, where high-quality solar and wind resources are abundant. However, these parts of the network were not originally designed to support such high connection density, and a number of investors are are already facing economic and technical challenges associated with connection to these weaker parts of the grid.

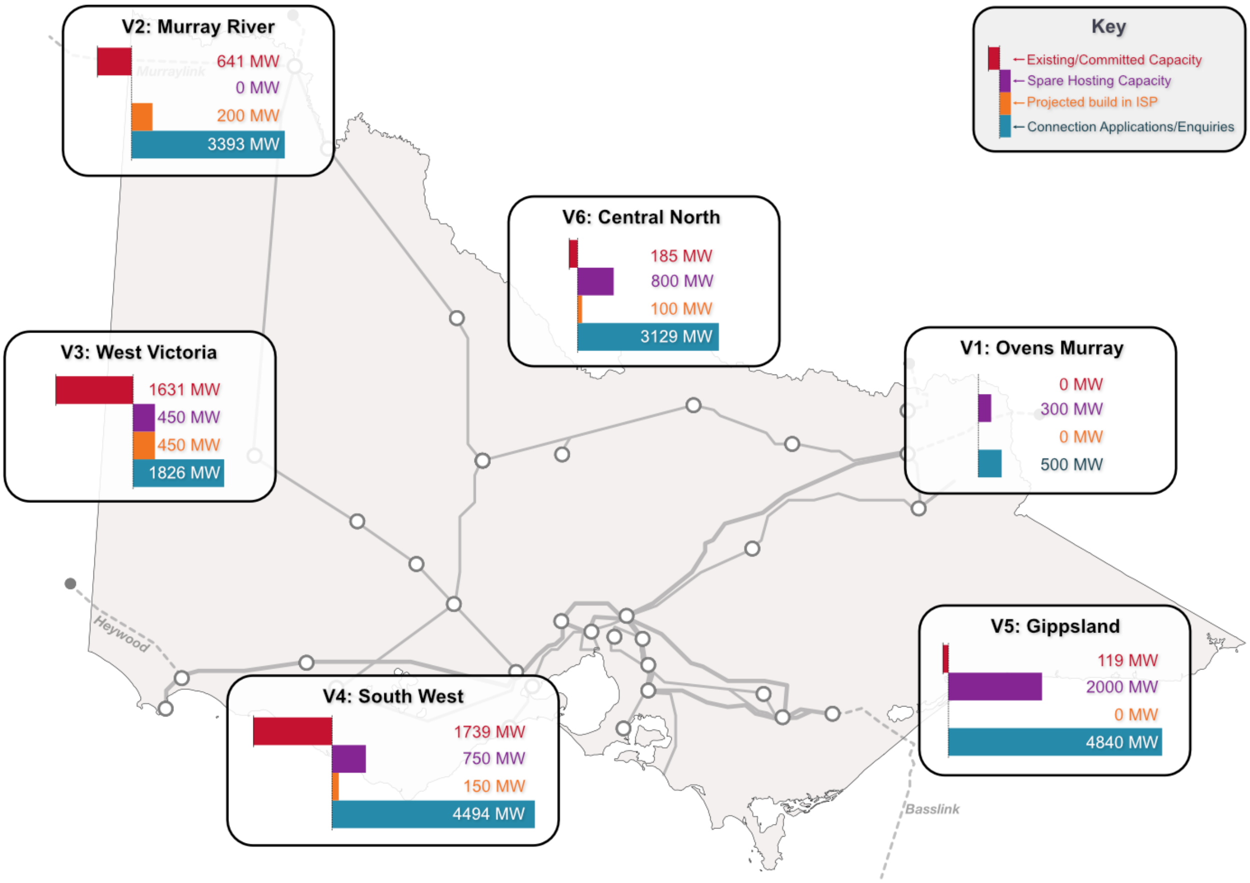
REZ hosting capacity

Through detailed market modelling, the 2020 ISP finds that to meet the VRET, up to 13.1 GW in total renewable generation would be required under its Central scenario (with updated demand), comprising 0.9 GW of additional large-scale investment, and 4.5 GW of additional DER. Alternative mixtures of large-scale and DER investments could also be used to meet the VRET under the ISP's optimal development plan, particularly following construction of the VNI West Interconnector.

As an input to this assessment, the ISP identifies six potential REZ candidates in Victoria, and assessed their remaining capacity to accommodate further generator investment (hosting capacity).

Figure 38 summarises these results, and overlays the projected build in the ISP's Central (with updated demand) scenario, and the current level of generation enquiries as at September 2020.

Figure 38 Summary of Victorian REZs under ISP Central scenario with latest ESOO demand forecasts



- Capacity values are based on the 2020 ISP, and include only large-scale wind and solar projects. Enquiries as at September 2020 from the connections map: https://aemo.com.au/-/media/files/electricity/nem/network_connections/maps/vic-map-2020.pdf?la=en.
- The hosting capacity includes the impact of the Western Victoria Transmission Network project.
- For consistency, the existing and committed capacities shown in the diagram are those that applied in the ISP modelling, although 600 MW of new projects have become committed since the ISP inputs were locked down.

The optimal development plan

Under these investment plans, the ISP confirms that demand growth and retiring conventional generation can be accommodated by a combination of renewable generation, dispatchable resources, and increased interconnection with other states.

This assumes that renewable generation to meet the VRET will be built in locations that could take best advantage of existing and projected network capabilities.

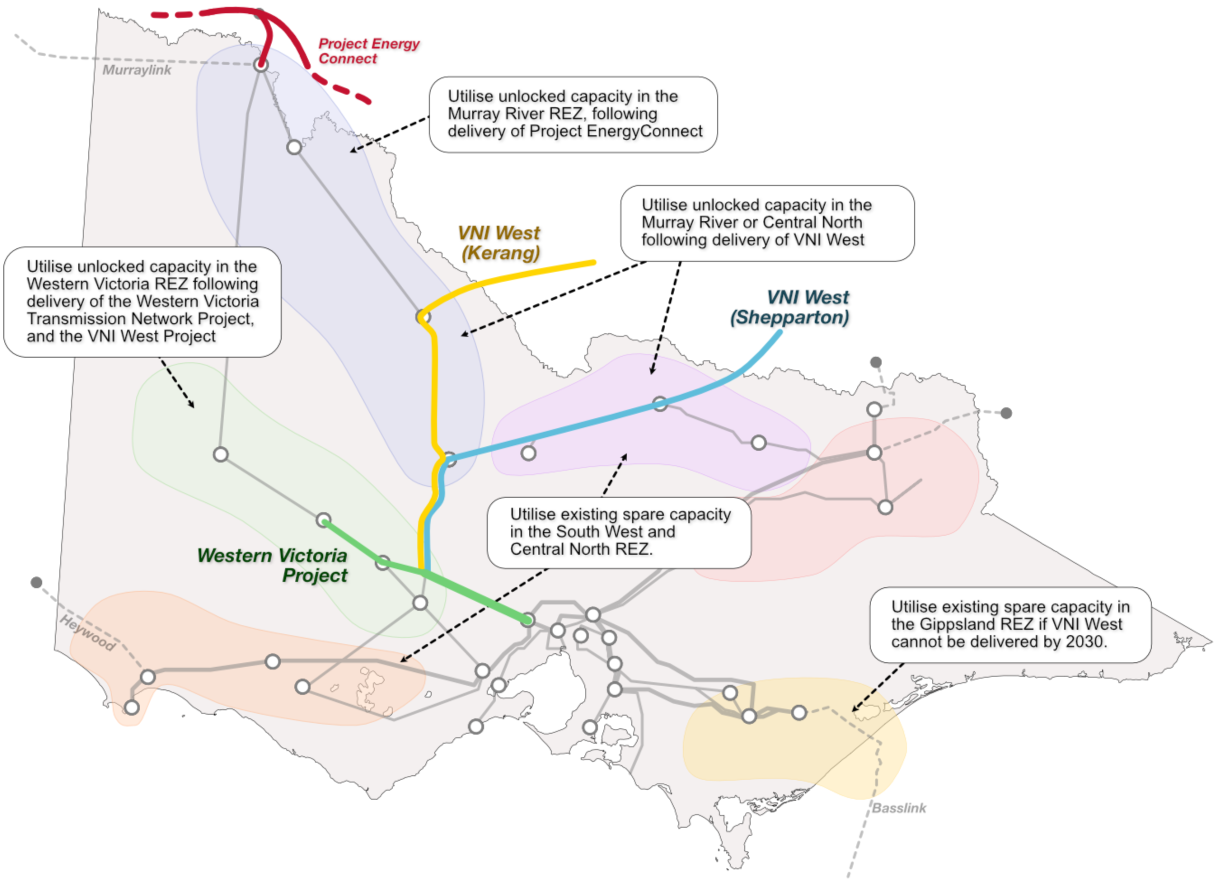
The ISP identified that a least-cost way to meet security, reliability, and policy objectives was to utilise:

- Spare capacity in the South West and Central North REZs.
- Unlocked capacity in the Western Victoria REZ, following delivery of the Western Victoria Transmission Network Project and later the VNI West Project (interconnection with New South Wales).
- Unlocked capacity in the Murray River REZ, following delivery of Project EnergyConnect (interconnection between South Australia and New South Wales).
- Unlocked capacity in the Murray River or Central North REZs, following delivery of the VNI West Project.
- Spare capacity in the Gippsland REZ if VNI West cannot be delivered before 2030.

Under the ISP's Step Change scenario, the model also expanded the South West REZ in 2036-37 by building an additional single circuit 500 kV line between Mortlake and a new terminal station north of Ballarat.

Figure 39 shows the breakdown of ISP results in the Central scenario.

Figure 39 2020 ISP expansion plan to meet the VRET target under the Central scenario



REZ development beyond the roadmap

AEMO's transmission roadmap includes all projects that are likely to deliver net economic benefits under the ISP's optimised generator expansion plans. However, while Figure 38 shows that there is enough developer interest in these optimal locations, specific developer considerations may still encourage investment in less optimal parts of the network, or in ways that deliver above minimum VRET build requirements.

As a result, some hosting capacities could be exceeded, and new system constraints could emerge that curtail the output of local generators, or result in delays to their connection processes. In general, the regulatory framework assigns these risks directly to individual developers as 'locational signals', that should encourage investment in more optimal locations.

Chapter 6 of the 2019 VAPR highlighted a range of these locational signals as an information resource to interested parties. This included the geographic impact of current thermal constraints, stability limitations, system strength requirements, and marginal loss factors. In 2020, AEMO's REZ Scorecards[100] provide further insights into the fuel and network quality available in each zone.

However, these signals are not always sufficient to drive investment decisions, and the relative construction lead times between generation and transmission investment can result in constrained generation assets. For example, the physical lead time to build a new large-scale wind, solar or battery system is approximately 1-2 years. In comparison, the RIT-T process for transmission investment can take 1-3 years before construction can commence.

As a prudent measure, AEMO is progressing an *REZ Development Plan* study, in parallel with the VAPR, that aims to understand how alternative geographic patterns of generator investment might impact on the optimal transmission roadmap for the state.

As an input into that process, AEMO has explored a number of potential REZ expansion projects that did not form part of the ISP's optimal build plan. These potential projects, from the 2020 ISP REZ Scorecards, are summarised in Table 19.

Table 19 Example REZ expansion augmentations

REZ	Augmentation option	Additional hosting capacity (MW)
Murray River	Extend Murray River REZ by augmenting the 220 kV network	+1,200 MW
Murray River	500 kV extension of Murray River REZ if VNI West (Shepparton route) is developed and interest for Murray River REZ is around Kerang	+1,500-2,000 MW
Western Victoria	Extend Western Victoria REZ by augmenting the 500 kV network	+1,500 MW
Western Victoria	Extend Western Victoria REZ by augmenting the 220 kV network	+1,000 MW
South West Victoria	Extend South West Victoria REZ by augmenting the 500 kV network	+3,000 MW
South West Victoria	Extend South West Victoria REZ by augmenting the 500 kV network to a new substation north of Ballarat	+2,500 MW
Central North Victoria	Extend Central North Victoria by augmenting the 500 kV network (if built before VNI West)	+1,700 MW
Central North Victoria	Extend Central North Victoria with additional 220 kV lines	+600 MW

[100] AEMO, 2020 ISP Appendix 5, July 2020, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

AEMO has also assessed potential future REZ system strength requirements driven by optimal generator build patterns (Section 4.5.2). However, individual connecting parties are required to fund their own system strength remediation activities, and demonstrate that their specific connection does not have an adverse impact on the overall system strength performance of the network.

Coordinated investment in system strength devices (by proponents or third-party investors) could result in a more efficient outcome overall, and the AEMC is currently investigating the system strength framework and its associated Rules[101,102].

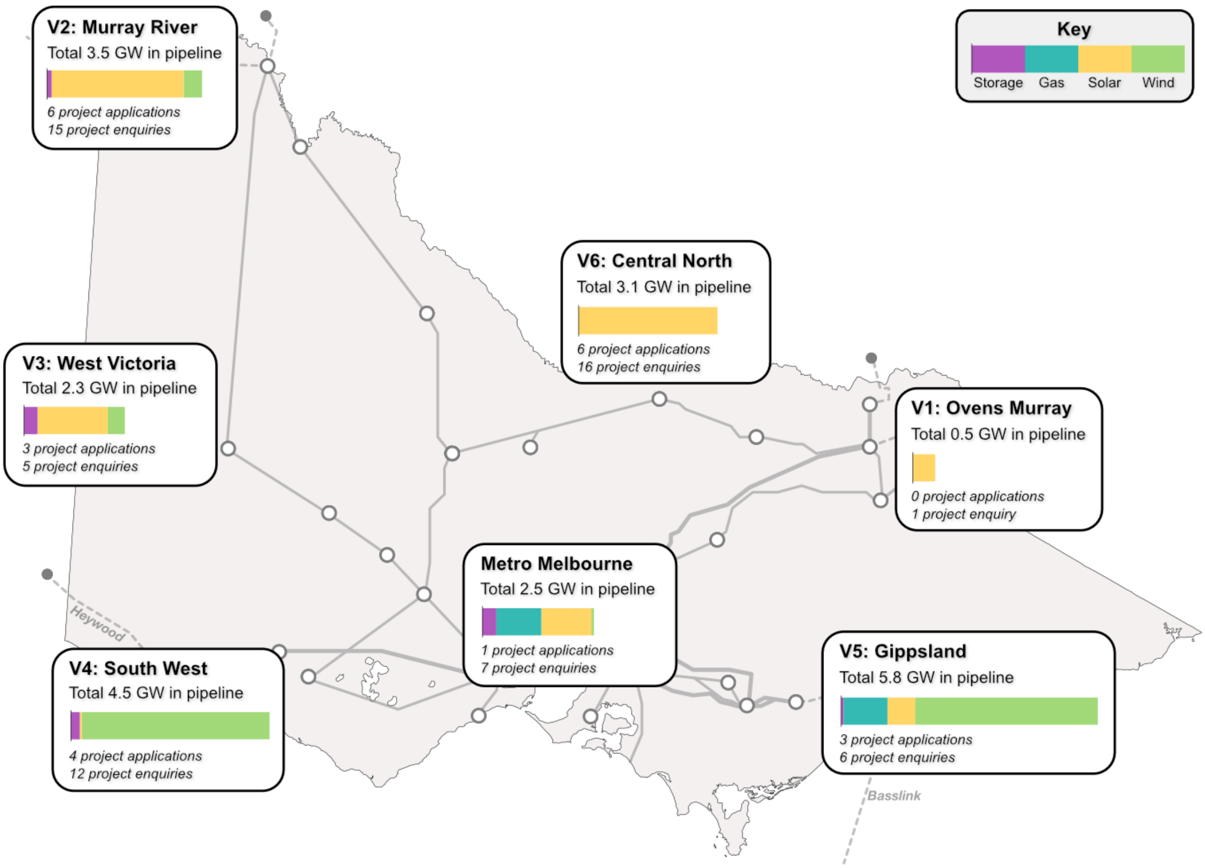
6.3 Adapting to changing connection needs

Investment interest in Victoria remains high, with many large-scale renewable generation and battery connections projects in the pipeline, as shown in Figure 40.

The connections process spans the entirety of a project enquiry through to commissioning and review of successive hold points of new plants. Management of connections also requires holistic assessment of the entire landscape to ensure an operational future network.

New challenges that are emerging as a consequence of the changing nature of connections can create issues at an individual plant level, or collectively for network operation. For example, single large capacity farm developments in the order of 500-1,000 MW typically have large reticulation systems that can impact the generator's ability to meet generator performance standards.

Figure 40 Current Victorian connections pipeline



As at September 2020: https://aemo.com.au/-/media/files/electricity/nem/network_connections/maps/vic-map-2020.pdf?la=en.

[101] See https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[102] See https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem.

At a system level, increased concentration of multiple projects in specific locations, such as in the West Murray and South West REZs, increases the potential for localised issues such as inverter interactions or constraints due to network congestion. The increase in volume of concurrent projects with similar registration timeframes could also see projects interact or impact on one another, requiring greater levels of coordination across project management and technical studies. The assessment of project clusters to capture such behaviours may be necessary.

Recent interest in the connection to the 500 kV network raises challenges for the management of the backbone of the DSN, including management of outages for commissioning and potential thermal congestion.

6.3.1 Connections uplift program

AEMO has initiated an uplift program of the Victorian connections process that aims to give stakeholders increased visibility of the connections process, enabling greater information sharing and transparency. This will empower proponents to proactively identify potential issues for proposed connection locations and explore solution options early in the connections process.

The uplift program will be progressed across the following workstreams:

- Resourcing and skills adequacy – AEMO is currently implementing a step change to expand its resource capabilities so appropriately skilled resources are available to assist proponents in working through the connections process. Where required, AEMO will also leverage consultant expertise to provide technical advice on complex generator performance issues.
- Common understanding of connections processes – AEMO will work with industry to clarify and standardise understanding of connections requirements, to improve consistency of the connections process across the NEM. AEMO will also invite proponents or manufacturers to prequalify generator models to help streamline the technical assessment processes. Appendix A4 provides a detailed summary of current resources available to provide more transparency and information to proponents.
- Account management and communication – AEMO will continue to assign dedicated project managers to projects, but this will be supported by a new stakeholder management system and the resourcing workstream described above. Increased project tracking aims to provide greater visibility to proponents on their project’s connection process and status. AEMO will also provide regular updates to key industry stakeholders on key challenges and milestones achieved.
- System expansion – AEMO is supporting delivery of the 50% VRET through the transmission roadmap outlined in this VAPR, and also progressing the development of its *REZ Development Plan* to explore alternative development pathways in Victoria that may support a generation build driven by alternative decisions. AEMO aims to work collaboratively with industry to develop novel, and where possible common, solutions to emerging technical issues.
- Regulatory reforms – AEMO will seek to engage with the Clean Energy Council and other interested stakeholders to consider interim and longer-term policy or rule changes to address current and emerging technical and logistical issues for connections.
- Enhanced system modelling – described in Section 6.3.2 below.

6.3.2 Power system modelling

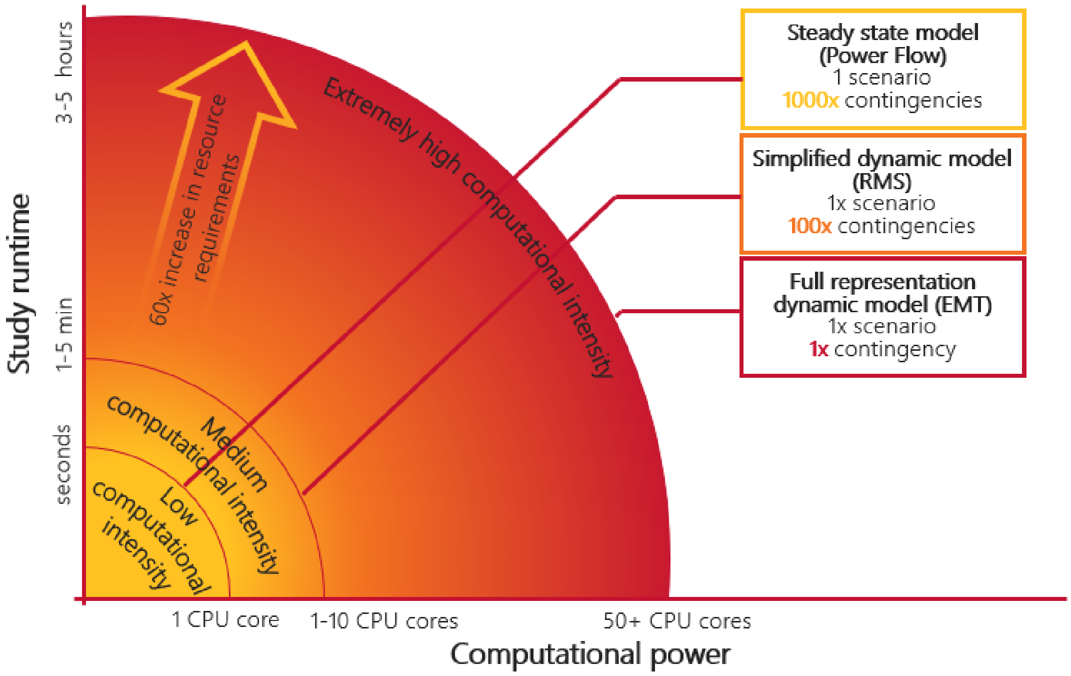
Detailed modelling is essential for technical assessments in weak areas of the grid; however, emerging clusters of inverter-based generation have pushed the boundaries of current modelling capabilities.

Over the past year, the nature and complexity of potential interactions in some parts of the network have required that studies be done incrementally to ensure that performance standards are met without causing adverse security or power quality issues.

EMT modelling is now an essential part of most connection studies, and EMT-type assessments are becoming increasingly necessary for both mid- and long-term planning. AEMO has continued to develop and benchmark its multi-region wide-area models, and is working to build out its internal modelling infrastructure and expertise. This includes leveraging future high speed monitoring as described in Section 3.3.5 for model validation. The validation of system and generator models will enable operation of the system closer to actual system capability.

Figure 41 shows the three key layers of AEMO's power system modelling capabilities, and provides an indication of their relative speed and computational intensity. The choice of a specific modelling approach depends heavily on the type of question being answered, and AEMO makes extensive use of all three across its operations, connections and planning functions.

Figure 41 Relative computational intensity and resource requirements of various system studies



To help proponents adapt to these new modelling needs, AEMO is working to develop an industry modelling platform that would provide access to a detailed EMT simulation environment that protects the confidentiality of detailed model information. The platform aims to provide connection applicants with the ability to design, tune and validate their own plant models ahead of (or in parallel with) the connections process.

6.4 Adapting to new operational challenges

This section considers new challenges in network operation that are already emerging, or that are likely to become material over the coming decade. The 2020 ISP projects that by 2029-30, Victoria could be operating with up to 120% of its instantaneous demand being supplied by renewable generation[103].

AEMO's Renewable Integration Study (RIS) Stage 1 report[104] identified three key characteristics of wind and solar generation that are likely to have an impact on future power system operations:

- More weather-dependent generation driving variability and uncertainty.
- Greater levels of geographically disperse generation capacity (particularly distributed PV).
- More inverter-based devices, decoupling system services from energy generation.

[103] Figure 6, Appendix 6 of 2020 ISP.

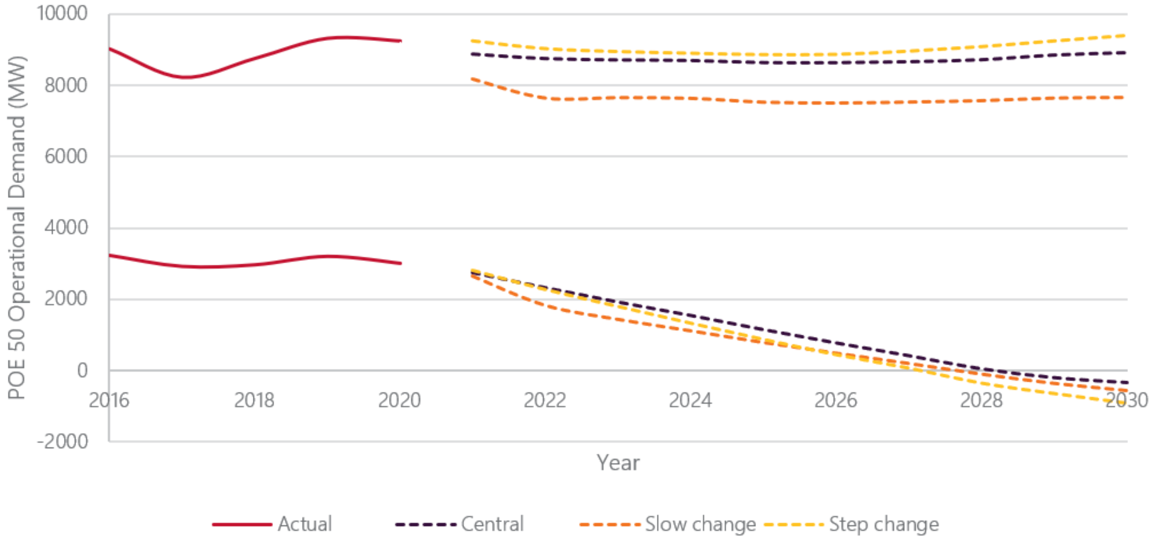
[104] At https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris.

These will impact both supply- and demand-side behaviour on the DSN:

- On the supply side, greater geographic and technological diversity will need to be supported through network capability and system services.
- On the demand side, increasing consumer participation will drive down operational demand, providing relief at maximum demand periods, but creating a range of challenges during low demands. The effects of growth in demand-side participation can be seen strongly in the widening gap between the maximum and minimum operational demand[105] projections in the 2020 ESOO, shown in Figure 42.

The remainder of this section explores several of these challenges in more detail, including how AEMO is adapting its planning approach in response.

Figure 42 2020 ESOO annual minimum and maximum operational demand projections (50% POE)



Note: POE, or Probability of Exceedance, is the likelihood a demand forecast will be met or exceeded. A 50% POE projection is expected to be met one year in two and represents average weather conditions.

6.4.1 Minimum operational demand thresholds

With maximum demand remaining relatively consistent, a decline in minimum operational demand does not reduce requirements for network infrastructure.

During times of low demand, the network plays a vital role in maintaining a secure power system, supplying essential system services rather than energy. Section 2.5.1 highlights that periods of low operational demand are already of concern for voltage control during system operation. The 2020 ESOO identifies several other issues arising from lower operational demands, including frequency control and system restart, both of which require stable load blocks. For emergency load shedding schemes – particularly under frequency load shedding, the size of individual load blocks will be reduced, increasing the geographic size of load shedding required in response to a supply shortfall or under-frequency event.

Section 4.4.4 details AEMO's activities related to voltage and system strength limitations as a consequence of the updated ESOO forecasts. AEMO will further consider the outcomes from dedicated reports on system strength, and inertia, and NSCAS requirements during low demand conditions in next year's VAPR.

With increased distributed PV installations, the probability of low demands will increase. Figure 43 compares the annual duration curves of projected operational demand against historical values by financial year.

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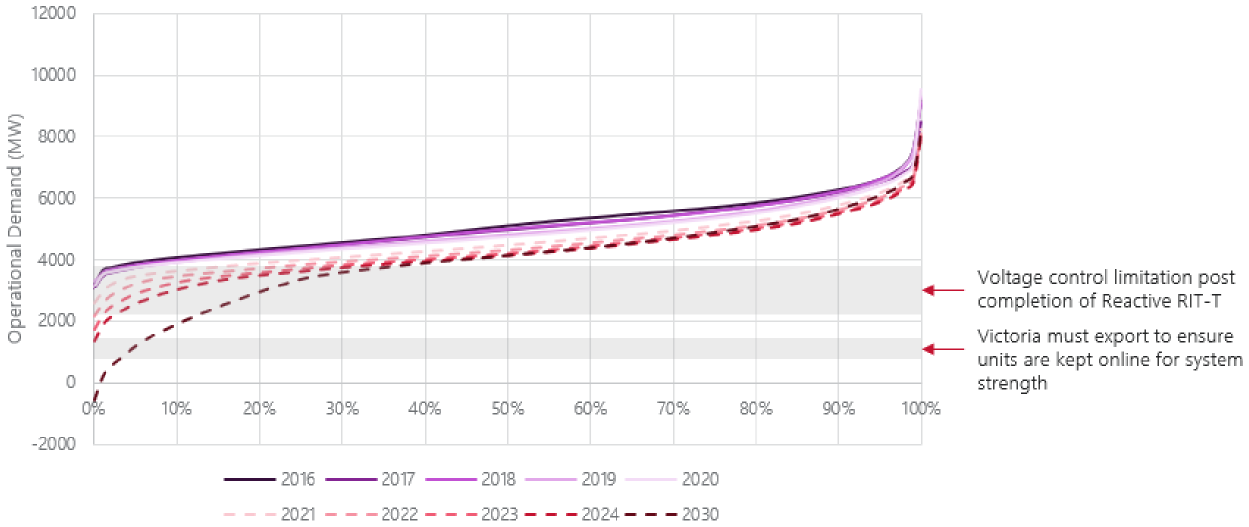
[105] Operational demand is the demand being supplied by large-scale generation and interconnection. The rapid decrease in minimum operational demand is driven primarily by distributed PV. Because distributed PV is behind the meter, it is currently only visible to the transmission system as a decrease in demand at distribution connection points. For a full set of demand definitions, see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/demand-terms-in-emms-data-model.pdf?la=en.

Figure 43 Indicative operational demand projection duration curves by financial year



Note: Projections are based on 2020 ESOO Central scenario operational demand traces using 2019 reference year and 90% POE demand.

As lower operational demands become more frequent, security limits will become binding more often. It is possible that a number of minimum demand thresholds as suggested above will need to be identified. This would require increased dispatchable load or a limit to the amount of distributed PV export to the network. AEMO is currently considering assessing the minimum level of operational demand under which the Victorian network can operate securely under various system conditions.

In future, to operate below these minimum thresholds, alternative supplies of essential system services will be required. This may be in the form of regulated assets, contracted services or market incentives.

6.4.2 Negative loads

AEMO's latest minimum demand forecasts project negative operational demands in Victoria by 2027. Increasing levels of embedded generation and distributed PV will continue to drive more frequent and higher magnitudes of reverse flows from the distribution network into the transmission network.

Under extremely low, or negative, load conditions:

- Excess supplies will be forced into the transmission network, where some equipment (and a number of control schemes) have been designed with single direction flows in mind. AEMO is currently reviewing existing control schemes in the network to ensure underlying assumptions remain valid (see Section 4.7). With the latest ESOO projections, further revisions to these schemes may be required in the medium term.
- A net surplus of generation (or negative load) at the transmission level will need to be exported to neighbouring states or have the capability to be curtailed locally. This could exacerbate system strength issues related to the minimum number of synchronous units online in Victoria (see Section 4.5.2).
- Assets that interface between the transmission and distribution networks may need to be reviewed, refurbished, or replaced to efficiently accommodate the new patterns of flow.
- Power quality and voltage control issues in the distribution network due to distributed PV may be transferred upwards into the transmission network.

AEMO will continue to engage with AusNet Services and the Victorian DNSPs to investigate and progress potential remediation activities associated with these emerging issues.

6.4.3 DER behaviour

By 2030, the ISP Central scenario projects 7.3 GW of distributed PV in Victoria, coupled with 233 MW of behind-the-meter battery storage. These installations can vary in performance and behaviour, and the aggregate behaviour of these installations may have a significant impact on the operating characteristics of the transmission network. However, there is currently limited visibility and controllability of these devices to AEMO as the system operator.

The trip of distributed PV following a network disturbance is an area of ongoing study. The risk of such a trip in South Australia currently impacts Heywood interconnector flows between Victoria and South Australia under low demand and high distributed PV conditions[106]. As Victoria transitions towards lower demands and high penetration of distributed PV installations, a similar risk may become material.

The 2020 ESOO identifies that the potential net contingency size due to DER and load reduction following a voltage disturbance could be as high as 560 MW by 2022[107]. This would compound the size of contingency represented by the original event, and any generation that might have been shed as a result. For example, if the original disturbance caused the tripping of a 600 MW generating unit, the additional 560 MW of DER reduction could bring the total contingency size to 1,160 MW, putting significant pressure on the system, interconnector flows, and contingency frequency control measures.

This changes the assumptions AEMO uses when developing constraint equations, and may result in the tightening of a number of constraints across the state. This is because the loss of DER is observed by the system as a sudden increase in demand, which may result in unexpectedly large flows, voltage disturbances, or cascade tripping events if not carefully managed in advance.

AEMO is currently undertaking a number of activities to improve the form and function of DER performance standards through both the AS/NZS 4777.2 review[108] and Rule changes that create a new framework for setting minimum technical standards for DER[109]. These actions will reduce the likelihood of sympathetic DER tripping and improve the autonomous responses of DER to ensure their behaviour supports reliable and secure power system operation.

Many learnings related to distributed PV will also be applicable to future DER, such as battery installations. Through the DER Program[110], AEMO is expanding its capabilities to better capture the impacts of these technologies on large-scale operations.

6.4.4 Climate risks and high impact, low probability (HILP) events

Long-term climate trends can have an impact on system planning through increasing average temperatures and changing likelihood of extreme events.

In the past year, the Victorian network has seen a number of significant unplanned outages due to HILP events, including the 4 January 2020 bushfire and 31 January 2020 downburst events identified in Chapter 2. Such events typically result from multiple faults and/or multiple unplanned outages on the system.

The operational impacts of such outages are compounded by their coincidence with high temperatures and peak demand periods. These are times of maximum system stress, where high temperatures also lead to generating units, voltage control equipment, and transmission infrastructure to be de-rated.

Diversity of supply technology and geography may help ease the impacts of these limitations by providing multiple sources of diversified supply, and AEMO is adopting a proactive approach to considering resilience in its future transmission planning processes. For example, bushfire risks were considered as part of the VNI West RIT-T, resulting in weighting towards greater route diversity[111].

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106 AEMO (May 2020), *Minimum operational demand thresholds in South Australia*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review.

107 Upper uncertainty bound based on 90% POE demand forecasts published in the 2020 ESOO.

108 See https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/as-nzs-4777-2-inverter-requirements-standard.

109 See https://www.aemc.gov.au/rule-changes/technical-standards-distributed-energy-resources.

110 See https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program.

111 For more information, see the VNI West PSCR at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west_rit-t_pscr.pdf?la=en.

In response to greater climate risks, and aligned with recommendations from the Brattle Group's report[112] (commissioned as part of the 2020 ISP), AEMO is:

- Collaborating with the Bureau of Meteorology (BOM) and CSIRO on the Electricity Sector Climate Information (ESCI) Project, due for completion in 2021, which will provide a view of climate vulnerabilities.
- Developing and adopting minimum national standards for resilience.
- Developing a list of potential solutions to help adapt to, minimise the impact of, or recover more quickly from, climate-related hazards and events.
- Leveraging outcomes of the ESCI project to assess climate risks and improve forecasting capabilities.

As these capabilities are developed, planning and investment decisions will increasingly be able to account for the relative resilience and economic impact of HILP events.

6.4.5 Inverter-based resource behaviour

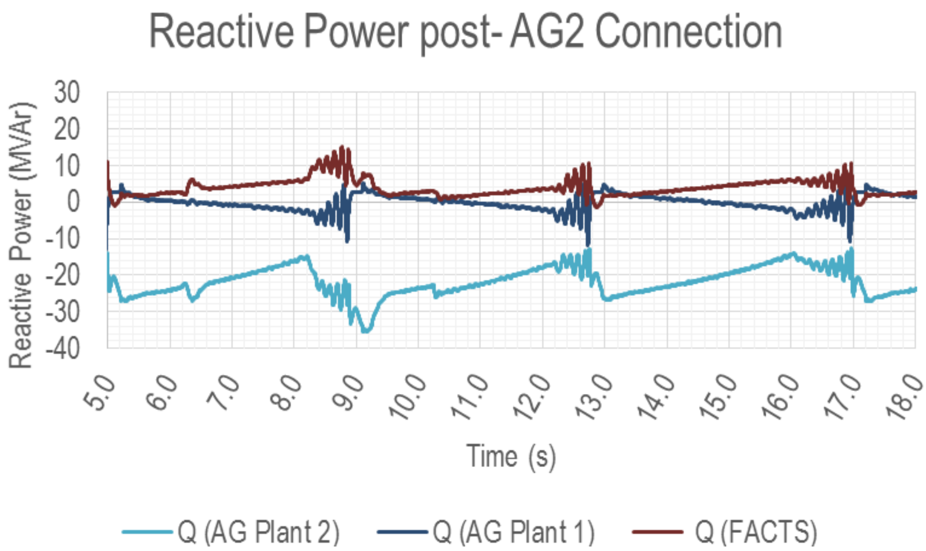
The response time of inverter-based resources can be much faster than the response of conventional generation types. This provides opportunities for additional fast frequency control system services. However, while this flexibility can be a useful tool, it can also introduce unexpected behaviours to the system.

A fast response may introduce more instability in the network, as the collective response of multiple inverters either overrespond (in unison), or counteract each other (in opposition). Figure 44 provides an example of this behaviour. To avoid these issues ongoing tuning of generator parameters may be required as more units are installed in an otherwise weak part of the network.

Inverter-based resources also require a minimum level of system strength to operate, so unstable inverter performance can be exacerbated in regions of low system strength. This was observed in the north-west of Victoria, and constraints needed to be imposed on local generation[113]. Potential solutions consist of a combination of inverter parameter tuning, and system strength remediation assets.

AEMO is seeking expressions of interest to address a system strength shortfall at Red Cliffs (see Section 3.3.4).

Figure 44 Example inverter interactions from two asynchronous plant models



Source: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2018/system_strength_impact_assessment_guidelines_published.pdf?la=en&hash=771B8F6BC8B3D1787713C741F3A76F8B.

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[112] See https://aemo.com.au/-/media/files/major-publications/isp/2020/brattle-group-report.pdf?la=en.

[113] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Power-System-Limitations-December.pdf.

6.5 Adapting to new technologies

There are a range of emerging inverter-based and battery technologies that pose viable technical solutions to existing and new network limitations. Joint configurations of such technologies in the form of virtual synchronous machines (VSMs) or virtual transmission lines (VTLs) can also offer unique technical characteristics that could be leveraged to address new challenges.

In some cases, these technologies can also be deployed more rapidly, and offer more modularity than traditional network solutions, making them a flexible addition to the network planning framework. However, due to this flexibility and the novelty of these technologies for large-scale network applications, TNSPs must take a prudent approach when integrating them into already stretched transmission systems.

AEMO is working to better accommodate these emerging technologies and promote even-handed consideration of non-traditional and non-network options in its planning processes. New technologies have featured strongly in AEMO's recent investment projects, and AEMO continues to partner and support a range of research, development, and technology pilot programs across Victoria.

While previous RIT-T assessments have found the economics of such technologies not yet competitive with traditional network solutions, this is changing rapidly as research, development, and international deployment ramp up. This section explores potential applications for inverter and battery technologies in addressing network challenges.

6.5.1 Grid-forming inverters

As more inverter-based generation sources are installed on the network, power electronic inverters will play a larger role in the operation of the power system. Most inverter-based connections are currently considered grid-following; this means they require the grid voltage and frequency as a reference point to stay in synchronism with the grid. An important pre-requisite is a stable voltage waveform that the grid-following inverter can track. As such, grid-following inverters are less able to operate in parts of the network exhibiting extremely low system strength and where synchronous sources are electrically distant.

Grid-forming inverters is a general term for devices that can use an internal voltage and frequency reference. These devices are less dependent on (or independent of) grid references, and have the potential to operate in weaker parts of the network. Grid-forming inverters can strengthen local voltage waveforms, and help support nearby grid-following inverters. However, grid-forming inverters also require extra layers of control systems to maintain synchronism, meaning they are currently deployed in smaller, islanded power system applications.

In a larger system, multiple grid-forming devices, that each follow their own reference point, may lead to an uncoordinated or distorted voltage waveform. To resolve this, coordination across the system needs to be considered during planning to avoid unexpected system incidents.

6.5.2 Battery energy storage systems

Inverters can be used to connect a range of generation sources, and the combined type of generation and inverter will determine the services and operating characteristics of the system – including energy intermittency, frequency response, reactive capability, and system strength.

Battery energy storage systems (BESS) coupled with advanced inverter technologies can provide a firm, controllable, dynamic source of energy and frequency control, and a range of localised system services.

The applications for a BESS are highly dependent on:

- **Response time** – how fast the battery can respond to disturbances on the system. This will be impacted by any measurements that may be required to trigger a response. A sub-second inverter response time to disturbances would allow the BESS to inject active or reactive power at rates comparable to traditional technologies.

- **Response characteristic** – how the inverter control scheme is set up will determine the response trajectory of the BESS. This may depend on other factors including state of operation at time of disturbance.
- **Storage capacity** – the sizing of the BESS will determine the maximum injection/absorption of power.
- **Storage duration** – this will determine how long the BESS is able to provide certain services.

While a BESS can provide several services commercially through existing market mechanisms (including energy, FCAS, RERT, and system restart ancillary services [SRAS]), additional network services that AEMO is investigating through its planning process include:

- **Load shifting capabilities** – where the BESS consumes energy and reduces flows along a transmission line at times of high network congestion, and then discharges this energy at a time when the system is experiencing lower stress, this behaviour can effectively reduce thermal limitations on the network and increase the utilisation of existing network assets. In remote parts of the network, this can be enough to replace the need for traditional network augmentations, particularly where generation sources are highly correlated with each other (such as areas of high wind or solar generation). A modified application of this is using multiple BESS units as a VTL (see Section 6.5.4). AEMO is exploring this option as part of its VNI West RIT-T (see Section 3.3.7).
- **Stability services** – a fast-response BESS can provide FCAS or offer network stability services to reduce the impact of voltage stability limitations on the system. As part of the VNI Upgrade RIT-T process (see Section 3.3.3), a confidential BESS proposal was considered and confirmed to improve stability limits. However, it was not taken forward as the preferred option, because the need for stability limit improvements had already been met by other proposed network augmentations[114].
- **System Integrity Projection Schemes (SIPS)** – BESS can also provide an alternative to load shedding or generation runback control schemes to alleviate post-contingency thermal limitations. Typically, 15-minute line ratings are used for thermal overloading of lines following a contingency, to provide enough time for generation re-dispatch to reconfigure flows on the network. Where a BESS (or equivalent fast start capacity) is available to offset the contingency event, five-minute line ratings can be used, allowing higher utilisation of existing lines. Such a battery would need to be sized appropriately to meet the instantaneous demand and have enough charge to supply the load for the required duration.

BESS are also modular in size and, depending on design, relatively easy to relocate in future. This provides benefits in flexibility of design, and shorter project delivery lead times. Given the fast pace of change on the Victorian network, and the steady decline in the cost of these technologies, BESS advantages are becoming increasingly attractive as an alternative or complement to network solutions.

6.5.3 Virtual synchronous machines

A VSM uses inverter-based technologies to emulate the behaviour of a traditional synchronous machine, and can be used in isolation (as a virtual synchronous condenser), or as part of a generating system (as a virtual synchronous generating system).

VSMs can be used to increase system strength by providing a stronger voltage reference for grid-following technologies in the local area. Because VSMs can be bundled with renewable or BESS technologies, such devices may be able to locate effectively in remote parts of the grid, and offer a variety of the services needed in those locations. Where virtual parameters are used (such as inertia), a VSM offers flexibility to adjust these parameters over time to meet changing system needs in the future.

The limitations to VSM technologies are commonly associated with their physical components. For example, fault current contribution from inverter-based plant is commonly limited to protect the power electronics of these devices. This is typically 2-3 times the MVA rating of a battery, in comparison to a large synchronous

[114] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/2019/vni-rit-t/victoria-to-new-south-wales-interconnector-upgrade-rit-t-padr.pdf.

machine which could provide up to six times its MVA rating. If larger fault current contributions are required, an increase in ratings (and cost) of power electronics would be needed.

AEMO, as the system strength and inertia service provider for Victoria, is required to remediate any declared shortfalls of these services. Section 4.5.2 and Section 4.5.3 respectively discuss the latest information on Victoria's emerging system strength and inertia needs.

Section 3.3.4 describes AEMO's two-phase project to remediate the currently declared system strength shortfall at the Red Cliffs node. As part of remediating this gap, AEMO is currently running a call for expression of interest for network and non-network services capable of providing at least 66 MVA of fault current contribution at Red Cliffs. Through this process, AEMO is open to innovative technologies such as VSMs that may be able to provide these services at the lowest cost.

6.5.4 Virtual transmission lines

A VTL, as defined for the purposes of this section, is a pair of BESS devices operating in coordination at either end of a transmission line. This approach can effectively (virtually) increase transfer capacity across a line, as suggested in Figure 45.

Figure 45 Conceptual representation of virtual transmission line

From a transmission network operation perspective, the application of a VTL could alleviate some post-contingent thermal limitations, and therefore increase supply reliability at times of high network stress.

Following a contingency event, the fast response times of both BESS devices allows power previously flowing across the physical line to instead flow across the VTL (through charging of one BESS, and discharging of the other).

This would temporarily reduce the need for generation runback or load shedding in response to the lost transmission line, and therefore minimise disruption to normal operation following the unplanned outage.

If flows are primarily in a single direction, the BESS on the sending end of the VTL could be removed. The excess generation would need to be reduced using an alternative method, such as lower FCAS services or generation fast trip schemes. If the excess generation is large, a sink will likely still be required to avoid widespread over-frequency generation tripping. Where this is the case, a braking resistor could offer a cost-effective alternative to the BESS.

Unlike traditional transmission lines, VTL devices can be located further away from the transmission asset they mirror. For example, in Figure 45, the BESS devices could be located at terminal stations further from the line, that may be more suitable for such connections.

While the figure above shows a pair of BESS units acting in unison, the VTL concept can be expanded to a broader system of BESS devices across a network – either in a 'daisy chain' between supply and demand, where subsequent lines may be congested at different times of day, or as a mesh, where an optimised control system could balance congestion in a way that best matches supply and demand profiles on the day. The commercial arrangements of such an application would need to be considered in detail, as this could have substantial impacts on the energy market and electricity spot prices in the region.

Further, with improvements in communication and coordination, the single BESS could be an aggregation of multiple smaller BESS on either side of a network, leveraging emerging DER arrangements such as virtual power plants. The increased geographic diversity offered by such devices could then reduce the impacts of single contingency events, and extreme weather events on transfer capability.

The size and duration of the VTL, and therefore its effectiveness in different circumstances, is limited primarily by the battery storage capacity, although it could be different in each direction.

The implementation of VTL may also have several limitations, including:

- Scaling the energy and capacity of such an implementation can become very expensive very quickly, and may not yet be cost competitive with major transmission network assets and interconnectors.
- Traditional AC transmission lines are typically able to transfer non-energy services (such as ensuring synchronism, system strength and fault levels). For a VTL to provide the same function, additional investment or advanced inverter technologies may be required.
- The complexity and coordination required between two (or more) BESS devices could create additional operational risks associated with control schemes, unexpected operation and outage planning.

To evaluate the costs, benefits, and risks of this approach for major transmission investment projects, AEMO is exploring potential VTL options as part of its VNI West RIT-T (see Section 3.3.7).

A1. DSN limitation detail

These details for transmission network limitations are grouped geographically.

The changes in the list of limitations are:

- New:
  - Insufficient reactive support in Melbourne Metropolitan Region.
  - Voltage stability in north-west Victoria and south-west New South Wales (export).
- Change in category:
  - Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana 220 kV line – this limitation is now considered a priority limitation as outlined in Section 4.3.
  - Ballarat – Terang – Moorabool 220 kV line – this limitation as it is now considered a priority limitation as outlined in Section 4.3.
  - Moorabool 500/220 kV transformer loading – this limitation is now considered a developing limitation.
  - High ROCOF in south-west Victoria – this limitation is now considered a developing limitation.
  - Voltage oscillation in western and north-western Victoria (under prior outage) - this limitation is now considered a developing limitation.
  - Dederang – Glenrowan – Shepparton – Bendigo 220 kV and Dederang – Shepparton 220 kV line loading - this limitation is now considered a developing limitation.
- Removed:
  - Long-term Victoria – New South Wales transfer limitation – this limitation has been removed as AEMO has initiated the VNI West RIT-T as outlined in Section 3.3.7.

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.

In this appendix, triggers are defined as the operating conditions under which a limitation may result in supply disruptions or constrain generation at increased frequency.

A1.1 Central North REZ

Limitations in the Central North REZ

Limitation	Limitation Type	Possible network solution	Trigger	2020 ISP/ 2019 NSCAS	Contestable project status
Dederang – Mount Beauty 220 kV line loading	Monitored	• 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 $12.8M.	Increased New South Wales import and export.	Not identified as a material limitation in the scenarios modelled.	These are unlikely to be contestable projects.
Dederang – Glenrowan – Shepparton – Bendigo 220 kV and Dederang – Shepparton 220 kV line loading	Developing	• 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 $48.5M. • Replace existing Dederang – Glenrowan, Glenrowan – Shepparton and Shepparton – Bendigo 220 kV lines with new double circuit lines at respective estimated costs of $71.8M, $64.4M, and $99.2M (total $235.5M).	Increased demand in regional Victoria and/or increased import from New South Wales. 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.	Identified limitation as part of Central North Victoria REZ	The new transformer or new transmission lines are likely to be contestable projects.

A1.2 Eastern Corridor

Limitations in the Eastern Corridor

Limitation	Limitation type	Possible network solution	Trigger	2020 ISP/ 2019 NSCAS	Contestable project status
Rowville – Yallourn 220 kV line loading	Monitored	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.
System strength shortfall at Hazelwood	Developing	Installation of a synchronous condenser at an estimated cost of $45.0M each.	Retirement of synchronous generators	Identified in 2020 ISP	This is likely to be a contestable project

A1.3 Northern Corridor

Limitations in the Northern Corridor

Limitation	Limitation Type	Possible network solution	Trigger	2020 ISP/ 2019 NSCAS status	Contestable project status
Eildon – Thomastown 220 kV line loading	Monitored	• Install wind monitoring scheme • Up-rate Eildon – Thomastown 220 kV line, including terminations to 75 °C operation, at estimated cost of $46.2M.	Increased New South Wales import and export.	Not identified as a material limitation in the scenarios modelled.	This is unlikely to be a contestable project.
Dederang 330/220 kV transformer loading	Monitored	Install a fourth 330/220 kV transformer at Dederang at an estimated cost of $14.9M.	At times of over 2,500 MW of imports from New South Wales 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 (import)	Monitored	• 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 (high demand in Victoria).	Not identified as a material limitation in the scenarios modelled.	These are both likely to be contestable projects.
Voltage stability at North Vic/South New South Wales (export)	Monitored	• Procure network support services • Install an SVC or a STATCOM at an estimated cost of $34.0M.	Increased export to New South Wales from Victoria under minimum demand in Victoria.	Constraint identified during high export to New South Wales.	These are both likely to be contestable projects.
Murray – Dederang 330 kV line loading	Monitored	• 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 $190M (excluding easement costs). • Install second 330 kV line from Dederang to Jindera at estimated cost of $157M (excluding easement costs).	Increased import from New South Wales to Victoria or Murray generation.	Not identified as a material limitation in the scenarios modelled.	These are both likely to be contestable projects.

A1.4 Murray River REZ

Limitations in Murray River REZ

Limitation	Limitation type	Possible network solution	Trigger	2020 ISP/ 2019 NSCAS	Contestable project status
Voltage oscillation in western and north-west Victoria (under prior outage)	Developing	• NMAS contracts. • Install an automatic generation runback control scheme.	• Increased probability of prior outages of local 220 kV transmission lines. • Reduced system strength in the region.	Constraint identified during high solar generation and prior outage.	These are likely to be contestable projects.
Red Cliffs – Wemen – Kerang – Bendigo 220 kV line (high generation)	Priority	• Install an automatic generation runback control scheme. • 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 $602 million.	Increased generation in Regional Victoria.	Identified as limitation as part of Murray River REZ.	These are likely to be contestable projects.
Voltage instability/collapse in North West Regional Victoria (around Wemen Terminal Station)	Priority	• NMAS contract for the use of spare reactive power capacity. • Install an automatic generation runback control scheme. • Install dynamic voltage regulation such as SVC at an estimated cost of $34.0M	Low local demand and high solar generation.	This was not identified as a limitation as it is a localised issue.	These are both likely to be contestable projects
Red Cliffs – Wemen – Kerang – Bendigo 220 kV line (high demand)	Monitored	• 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 $602 million.	Increased demand in Regional Victoria.	Not identified as limitation as it is a localised issue.	These are likely to be contestable projects.

A1.5 South West Victoria REZ

Limitations in the South West Victoria REZ

Limitation	Limitation Type	Possible network solution	Trigger	2020 ISP/2019 NSCAS	Contestable project status
Ballarat – Terang – Moorabool 220 kV line	Priority	• Install an automatic generation runback control scheme. • Replace the existing Ballarat – Terang – Moorabool 220 kV line with a new double circuit 220 kV circuit line.	Increased generation in regional Victoria.	Identified as limitation as part of South West Victoria REZ.	These are likely to be contestable projects.
Moorabool – Heywood – Portland 500 kV line voltage unbalance**	Monitored	• A switched capacitor with individual phase switching at Heywood or near Alcoa Portland with an estimated cost of $14.7M. • An SVC or a STATCOM at an estimated cost of $34.0M. • Additional transposition towers along the Moorabool – Heywood – Alcoa Portland 500 kV line at an estimated cost of $38.7M.	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, new generation connection points, and output generated.	Limitation not found as part of 2020 ISP/2019 NSCAS 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	Monitored	A new Moorabool – Mortlake/Tarrone – Heywood 500 kV line with an estimated cost of $572.0M.	If significant wind generation and/or gas-powered generation (GPG) (over 750 MW in addition to the existing generation from Mortlake) is connected to the transmission network in the South-West Corridor.	Identified as a limitation in 2020 ISP South West Victoria REZ Scorecard.	The new line is likely to be a contestable project.
Moorabool 500/220 kV transformer loading	Developing	• Install an automatic generation runback control scheme. • Install third Moorabool 500/220 kV transformer costing approximately $25.6M.	Large-scale new generation connected to western Victoria area, and congestion in 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	Developing	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 likely to be a contestable project.

Limitation	Limitation Type	Possible network solution	Trigger	2020 ISP/2019 NSCAS	Contestable project status
Voltage collapse in South West Victoria	Developing	To be confirmed	Increased generation on the MLTS – HYTS lines and high import from South Australia.	Not identified.	To be confirmed

** AEMO intends seeking a Rule change proposing an increase the negative sequence voltage imbalance levels on the transmission network.

A1.6 Greater Melbourne and Geelong

Limitations in Greater Melbourne and Geelong

Limitation	Limitation Type	Possible network solution	Trigger	2020 ISP/ 2019 NSCAS status	Contestable project status
Ringwood – Thomastown and Templestowe – Thomastown 220 kV line loading	Monitored	• 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 $14.5M plus any fault level mitigation work. • New (third) 500/220 kV transformer at Rowville, with an estimated cost of $54.3M, 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**	Monitored	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 $11.3M.	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	Monitored	• Connect a third Rowville –Springvale circuit (underground cable) with estimated cost of $57.1M. • Connect a Cranbourne – Heatherton 220 kV double circuit overhead line with estimated cost of $37.0M.	Increased demand or additional loads connected to Springvale and Heatherton Terminal Station.	Not identified as it is a localised issue.	The third circuit is likely to be a contestable project.
Rowville A1 500/220 kV transformer loading	Monitored	Install a second 500/220 kV 1,000 MVA transformer at Cranbourne with estimated cost of $25.6M.	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	Monitored	Replace the existing transformer with a higher rated unit in conjunction with AusNet Services asset replacement program.	Increased demand in Metropolitan Melbourne and/or increased import from New South Wales.	Not identified as a material limitation in the scenarios modelled.	This is unlikely to be a contestable project.

Limitation	Limitation Type	Possible network solution	Trigger	2020 ISP/ 2019 NSCAS status	Contestable project status
Cranbourne A1 500/220 kV transformer loading	Monitored	Install a new 500/220 kV transformer at Cranbourne Terminal Station with an estimated cost of $25.6M (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.
South Morang – Thomastown No. 1 and No. 2 220 kV line loading	Monitored	• 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 $25.6M, plus any fault level mitigation works.	Increased demand around the Melbourne Metropolitan area and/or increased export to New South Wales.	Not identified as it is a localised issue.	The new transformer is likely to be a contestable project.
Moorabool – Geelong - Keilor 220 kV line loading	Monitored	• Connect a new single circuit Moorabool – Geelong 220kV line with a rating of approximately 800 MVA at 35°C, with an estimated cost of $11.5M. • 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 $78.2M.	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.	This is unlikely to be a contestable project.
Keilor – Deer Park – Geelong 220 kV line loading	Monitored	• Installing a load shedding control scheme • 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 $11.5M. • Replace 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 $78.2M. • 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 $3.2M.	Increased demand at Deer Park.	Not identified as a material limitation in the scenarios modelled.	These are unlikely to be contestable projects.
Sydenham – Keilor 500 kV line	Monitored	• Install 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 $37.6M. • Uprate line rating of the existing 500 kV Sydenham Terminal Station (SYTS)–KTS.	Increased generation in west and south-west Victoria supplying Keilor Terminal Station.	Not identified as a material limitation in the scenarios modelled.	These are likely to be contestable projects.

Limitation	Limitation Type	Possible network solution	Trigger	2020 ISP/ 2019 NSCAS status	Contestable project status
Melbourne Metropolitan Area voltage stability	Monitored	• Additional capacitors. • An SVC or a STATCOM at an estimated cost of $34.0M.	Increased maximum demand in the Melbourne Metropolitan area.	Not identified as a material limitation in the scenarios modelled.	These are likely to be contestable projects.
Insufficient reactive support in Melbourne Metropolitan and south-west transmission corridor	Developing	• Additional reactors at an estimated cost of $6.5M each. • Installation of a synchronous condensers at an estimated cost of $45.0M each. • An SVC or a STATCOM at an estimated cost of $34.0M.	Decreased minimum demand in Melbourne metropolitan area.	Identified in 2019 NSCAS.	These are likely to be contestable projects.
System strength shortfall at Thomastown	Developing	• Installation of a synchronous condenser at an estimated cost of $45.0M each	Retirement of synchronous generators.	Identified in 2020 ISP.	This is likely to be a contestable project.

* This monitored limitation assumes five-minute ratings are already applied. An automatic load shedding control scheme to enable five-minute line ratings is currently available to manage this limitation.

A1.7 Western Victoria REZ

Limitations in Western Victoria REZ*

Limitation	Limitation type	Possible network solution	Trigger	2020 ISP/2019 NSCAS	Contestable project status
Red Cliffs – Kiamal – Murrawarra - Horsham- Bulgana 220 kV line	Priority	Install an automatic generation runback control scheme.	Install an automatic generation runback control scheme.	Install an automatic generation runback control scheme.	Install an automatic generation runback control scheme.
Inadequate reactive power support in Regional Victoria	Monitored	Staged installation of additional reactive power support in Regional Victoria.	Increased maximum demand and/or reactive power consumption in regional Victoria.	2020 ISP/NSCAS did not identify this limitation as it is a localised issue.	Additional reactive support is unlikely to be a contestable project.

A2. Distribution network service provider planning

This appendix lists the preferred connection modifications from the *2019 Transmission Connection Planning Report*[115] and the potential DSN impacts and considerations.

Location/terminal station	Preferred connection modification	DSN impacts and considerations
Altona No. 3 and 4 66 kV	Install additional transformation capacity and reconfigure 66kV 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 220/66kV transformer by end of 2022, unless an alternative non-network development arises.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.
Wemen 66 kV	Additional embedded generation may justify additional transformation capacity	Monitoring embedded generation output levels will continue.

[115] Jemena, CitiPower, Powercor, AusNet Services and United Energy, at https://www.unitedenergy.com.au/wp-content/uploads/2019/12/2019-Transmission-Connection-Planning-Report.pdf.

A3. Approach to network limitation review

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.
- Expected unserved energy (USE), which is the energy at risk after accounting for forced outages.
- Dispatch cost, which is the additional cost from constraining generation.
- Limitation cost, which is the total additional cost due to both constraining generators and expected USE.

Power system performance analysis uses conservative assumptions for demand, temperature, and wind speed to capture as many network limitations as possible for market simulation. 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% Probability of Exceedance (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 flow 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 which AEMO considers necessary to maintain power system security or reliability during summer maximum demand.
- Standard continuous ratings and short-term ratings at 45°C and 0.6 m/s wind speed.
- Unless indicated, 15-minute ratings for transmission lines. Some transmission lines in Victoria are equipped with automatic load shedding schemes, which avoid overloading by disconnecting load blocks following a contingency. These schemes allow lines to operate to 5-minute ratings.
- Wind generation availability during maximum demand assumed to be 9.5% of the installed capacity.

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, and historical load profiles.
- Dynamic ratings based on historical temperature traces.
- Non-committed new and retired generation, consistent with the latest ISP.

For more information, see the *Victorian Electricity Planning Approach*[116].

[116] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-transmission-network-service-provider-role.

A4. Connection insights

This appendix builds on Chapter 6 of the 2019 VAPR. It provides information and resources to help new and intending participants better understand the locational signals and changing investment landscape in Victoria.

A4.1 Current investor interest

Investors are continuing to favour the western Victoria region, with interest in solar and large capacity wind projects rapidly increasing, while energy storage solutions are increasingly being considered as a means of diversifying developer revenue streams and minimising exposure to network constraints.

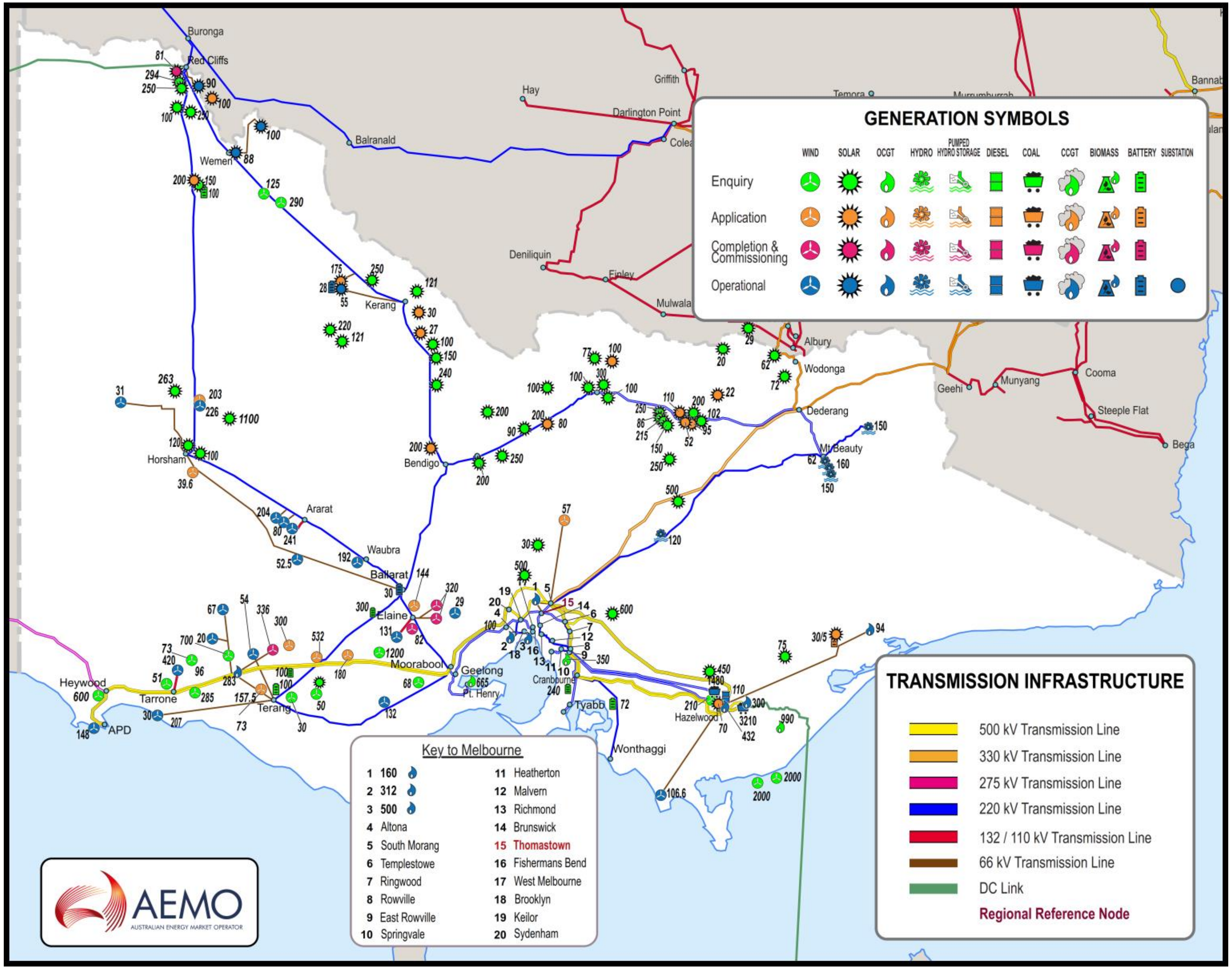
Figure 46 presents a spatial representation of connection applications in Victoria[117].

There is currently 16 GW of renewable generator projects in the early enquiry phase of the transmission connections process. 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[118].

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

[118] AEMO, Connecting Generator Clusters to the Victorian Electricity Transmission Network, 2010, at https://aemo.com.au/-/media/files/electricity/nem/network_connections/vic/connecting-generator-clusters-to-the-victorian-electricity-transmission-network.pdf.

Figure 46 Spatial representation of aggregated connection applications



A4.2 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 NSP and by AEMO[119].

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 for an existing generator 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.

A4.2.1 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)[120]. 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.

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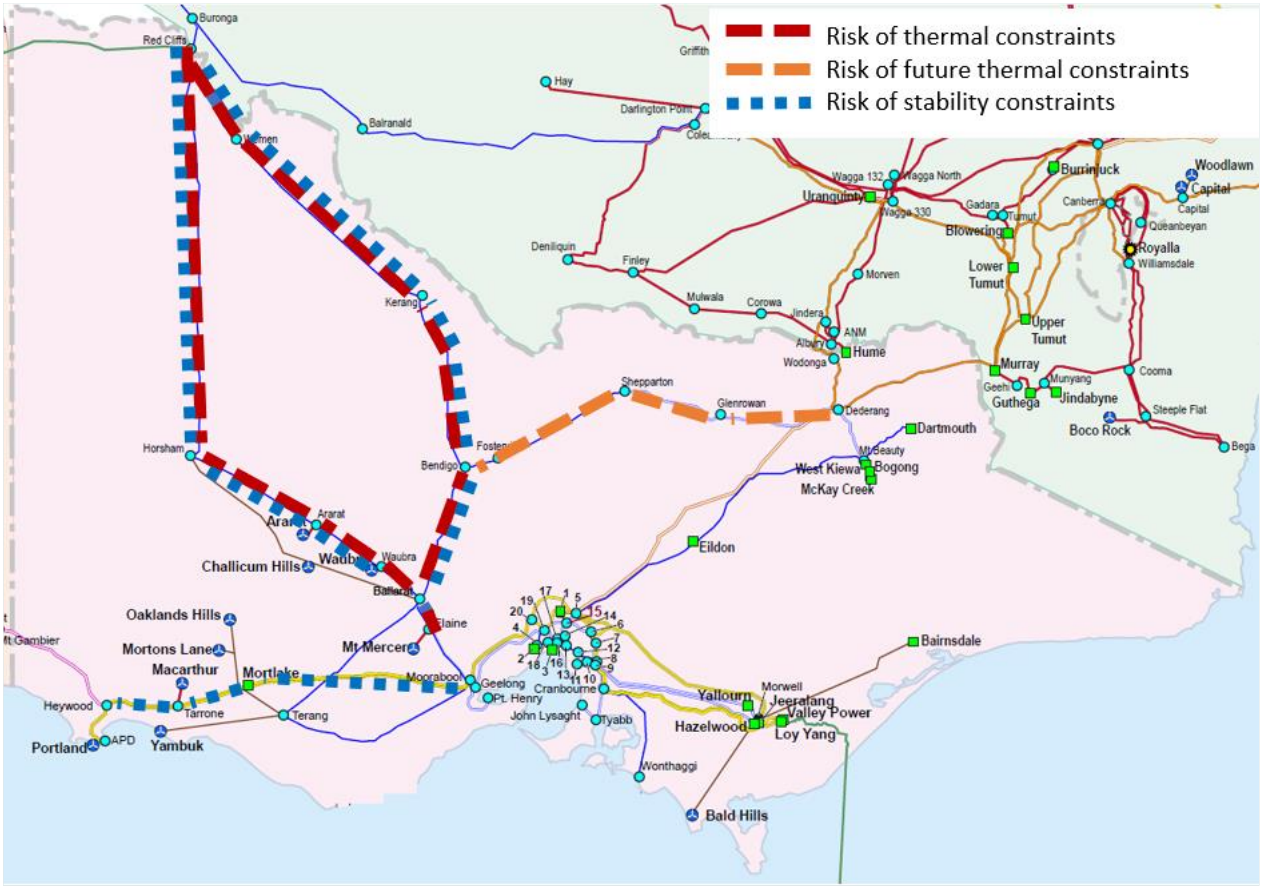
[119] For an overview of the connection process, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview.

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

Figure 47 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 47 Potential constraints risks for new generators in Victoria



Mitigating the risks of network constraints

It is crucial that new and intending generator proponents understand the impact that network constraints and network congestion may have 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[121], 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*[122], 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.

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

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

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 help 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 projects 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, to minimise thermal and stability constraints.
- Implementing dynamic reactive devices to improve voltage stability in weak areas of the network.

A4.2.2 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 transmission losses are represented as MLFs at every existing load or generation connection transmission section 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.

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. Therefore, 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[123].

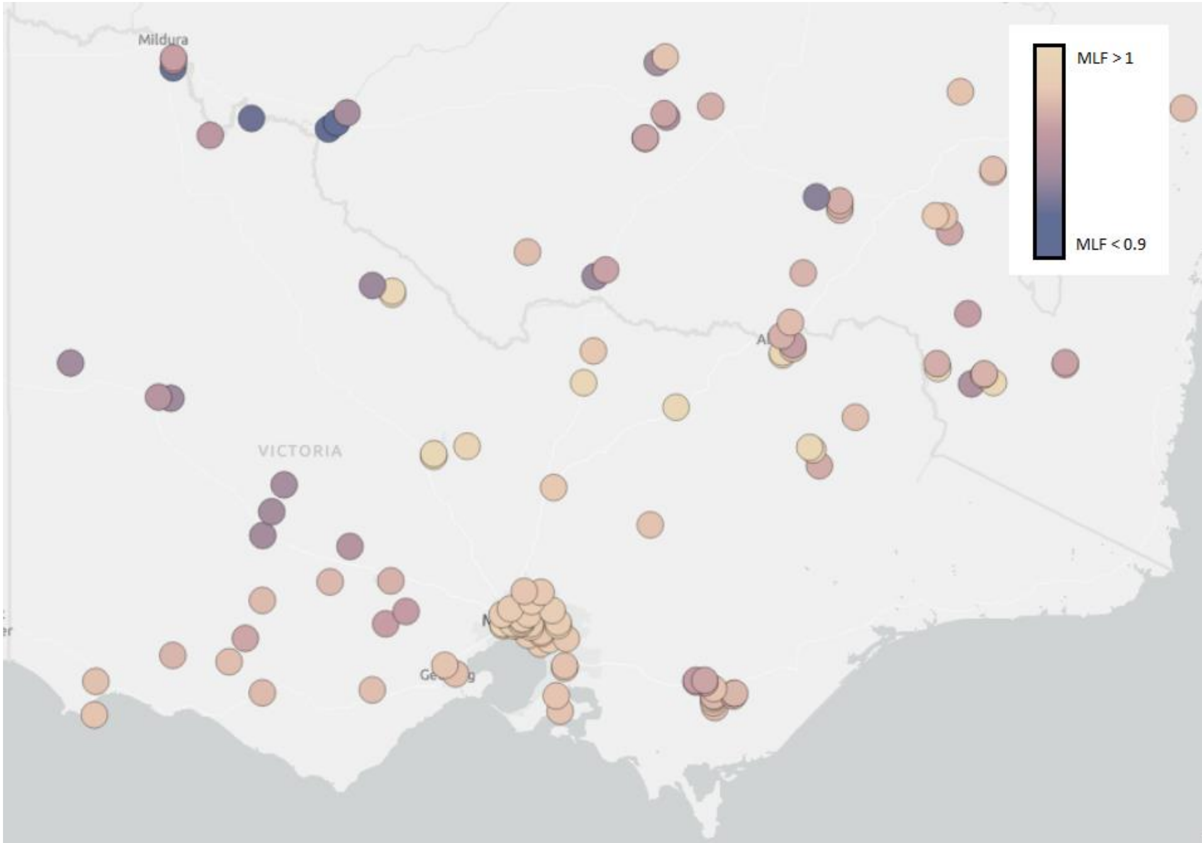
Investors should carefully consider the impact of MLFs when assessing the financial viability of a project, including exposure to future MLF changes over time.

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

Current MLF levels

AEMO has published a *Regions and Marginal Loss Factors* report[124] detailing 2020-21 MLFs for each connection point in the NEM. Figure 48 illustrates Victoria's 2020-21 MLFs[125].

Figure 48 Map of 2020-21 MLFs for connection nodes in Victoria



As detailed above, MLFs are heavily dependent on a number of factors which influence network losses, including local demand, local generation, network power 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 also 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 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.

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

125 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/aemo/apps/visualisations/map.html.

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

6.5.5 System strength

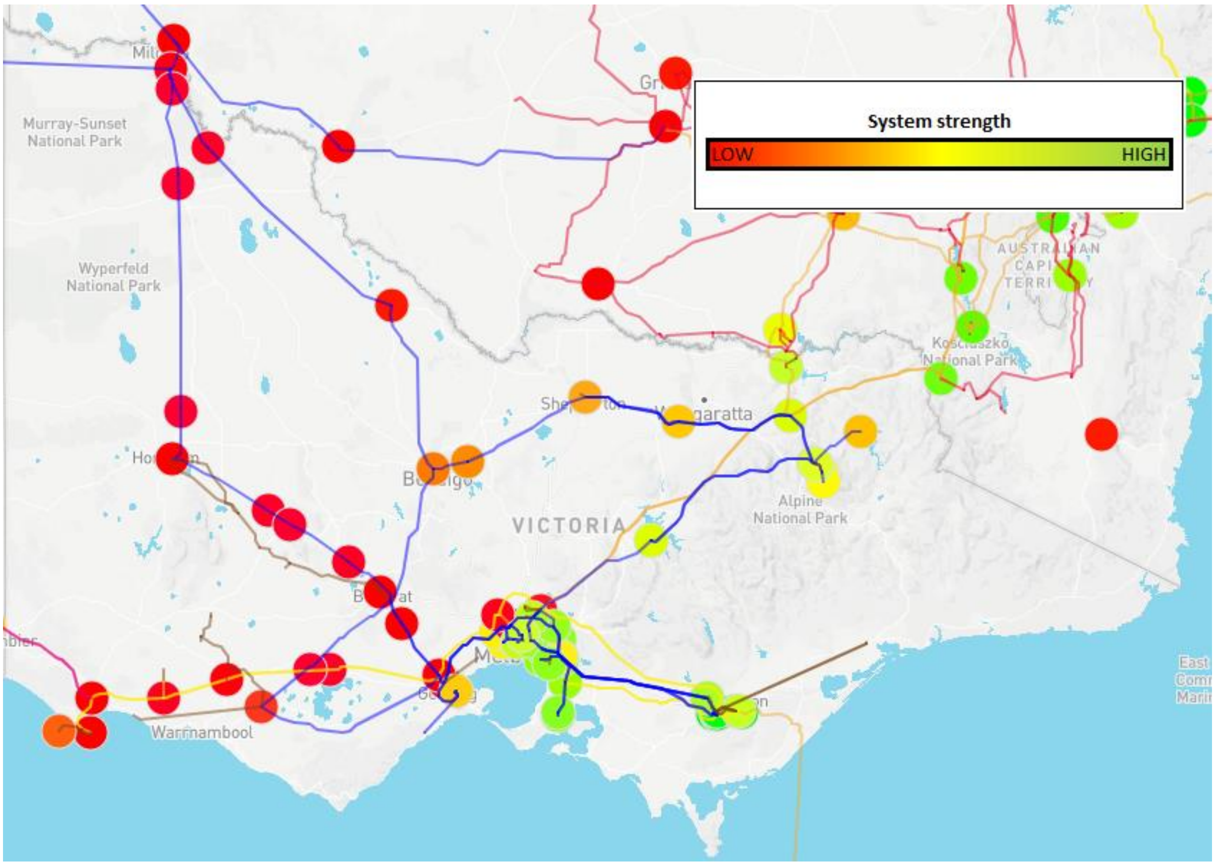
System strength is a measure of the ability of a power system to remain stable under normal conditions and to return to a stable state following a system disturbance. A key issue arising from the integration of non-synchronous generation to the power system, and the withdrawal of traditional synchronous 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 most 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 2020 ISP, AEMO has published an interactive map showing system strength levels for each connection node in 2020-21, and indicative system strength levels in 2029-30 and 2034-35.[126] Figure 49 provides the current snapshot of this map.

Figure 49 Current system strength levels in Victoria 2020-21



[126] Select '2020 Integrated System Plan – System Strength' layer at http://www.aemo.com.au/aemo/apps/visualisations/map.html.

NER system strength requirements

In 2017, the AEMC published a set of Rule changes which prescribed a framework for maintaining system strength on the power system[127]. There are two aspects to this framework:

- Each region's System Strength Service Provider (SSSP) is required to maintain the minimum three-phase fault levels at each fault level node in each region, as determined by AEMO[128].
- 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 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[129] 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*[130]. 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

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

[128] 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.

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

[130] 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 remediation 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) to share the costs of system strength remediation investment.

A4.3 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 50 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[131]. This is consistent with other NSPs in the NEM[132].

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[133].

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

Pre-feasibility[134]

- 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[135].
- 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.

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

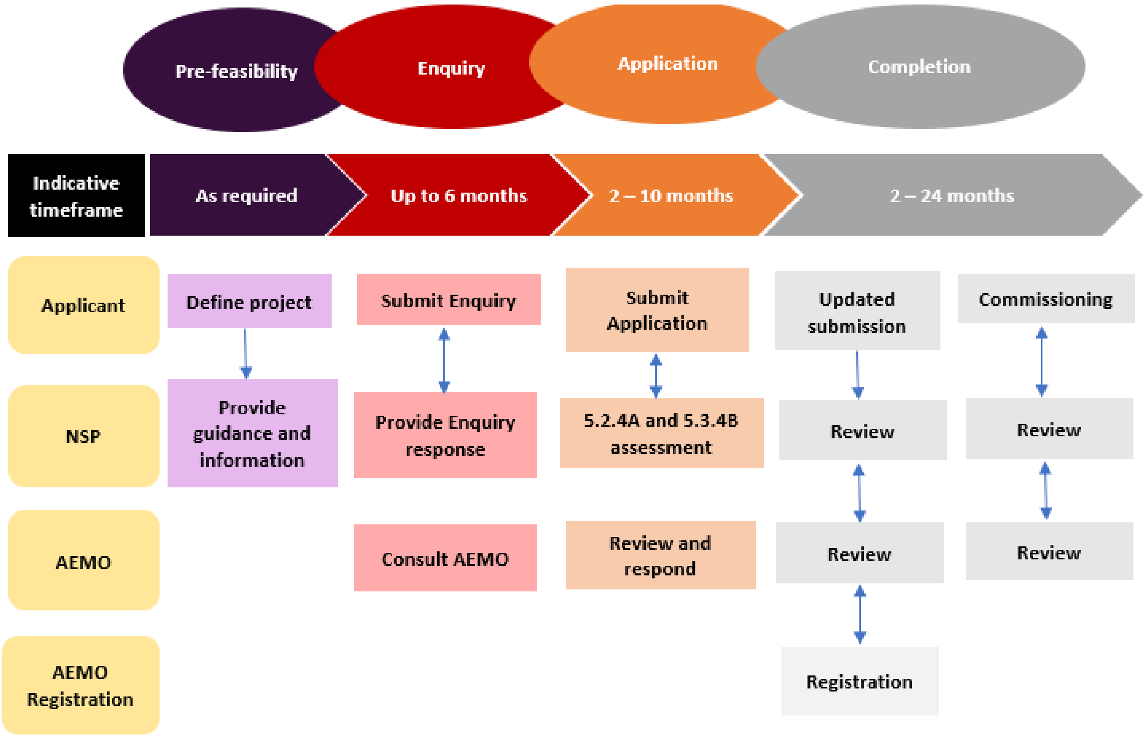
[132] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/NSP-connction-process-diagram-v20.pdf.

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

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

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

Figure 50 Key technical stages of connections process



Enquiry[136]

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 must submit a Connection Enquiry Form[137] 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[138]

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[139]. They include the following technical inputs:

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

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

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

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

- Proposed performance standards[140]. 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[141].
- 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[142]

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[143].
- 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[144].
- 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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[140] 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.

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

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

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

[144] 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.

Abbreviations

Abbreviation	Term in full
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APD	Alcoa Portland
BESS	Battery energy storage system/s
BOM	Bureau of Meteorology
CBTS	Cranbourne Terminal Station
COAG	Council of Australian Governments
CRM	Customer relationship management
DER	Distributed energy resources
DNSP	Distribution Network Service Provider
DSN	Declared Shared Network
DSP	Demand-side participation
DTSO	Declared Transmission System Operator
EFCS	Emergency Frequency Control Scheme
EMT	Electromagnetic Transient
EPS	Eildon Power Station
ESB	Energy Security Board
ESCI	Electricity Sector Climate Information
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
GFT	Generation fast tripping
GPG	Gas-powered generation
GW	Gigawatts
HILP	High impact, low probability
HSM	High-speed monitors

Abbreviation	Term in full
HVDC	High-voltage direct current
HWPS	Hazelwood Power Station
IECS	Interconnector Emergency Control Scheme
IRM	Interim Reliability Measure
ISP	Integrated System Plan
JPB	Jurisdictional Planning Body
KTS	Keilor Terminal Station
kV	Kilovolts
LGC	Large-scale generation certificates
LOR	Lack of Reserve
MLF	Marginal loss factor
MLTS	Moorabool Terminal Station
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
NCIPAP	Network Capability Incentive Project Action Plan
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NEVA	National Electricity Victoria Act
NMAS	Non-market ancillary services
NSCAS	Network Support and Control Ancillary Services
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PMU	Phasor Measurement Unit
POE	Probability of exceedance
PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic
RERT	Reliability and Emergency Reserve Trader

Abbreviation	Term in full
REZ	Renewable energy zone
RIS	Renewable Integration Study
RIT-T	Regulatory Investment Test for Transmission
ROCOF	Rate of change of frequency
ROTS	Rowville Terminal Station
RRN	Regional reference node
SCADA	Supervisory Control And Data Acquisition
SIPS	System Integrity Protection Scheme
SMTS	South Morang Terminal Station
SRAS	System restart ancillary services
SSSP	System Strength Service Provider
SVC	Static Var compensator
TNSP	Transmission network service provider
TRET	Tasmanian Renewable Energy Target
TSDF	Terminal station demand forecast
TTS	Thomastown Terminal Station
UFLS	Under-frequency load shedding
USE	Unserved energy
VAPR	Victorian Annual Planning Report
VNI	Victoria – New South Wales Interconnector
VPP	Virtual power plant
VRE	Variable renewable energy
VRET	Victorian Renewable Energy Target
VSAT	Voltage stability assessment tool
VSM	Virtual synchronous machine
VTL	Virtual transmission line
YPS	Yallourn Power Station