2020 Network Support and Control Ancillary Services (NSCAS) Report

December 2020

A report for the National Electricity Market

Important notice

PURPOSE

AEMO publishes the National Electricity Market Network Support and Control Ancillary Services Report under clause 5.20.3 of the National Electricity Rules.

The underlying analysis for this report has been prepared by AEMO using information available at 1 November 2020. Information made available after this date has been included in this publication where practical. This document or the information in it may be subsequently updated or amended.

DISCLAIMER

This publication contains data provided by or collected from third parties, and conclusions, opinions, assumptions or forecasts that are based on that data. Anyone proposing to use the information in this publication should independently verify its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

AEMO has made every reasonable effort to ensure the quality of the information in this publication but cannot represent that it is accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require. It does not amount to legal or business advice, or a recommendation of any investment.

This document or the information in it may be subsequently updated or amended.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

VERSION CONTROL

Version	Release date	Changes
1.0	17/12/2020	Initial release

Executive summary

AEMO's Network Support and Control Ancillary Services (NSCAS) review for the National Electricity Market (NEM) has assessed the need for any additional system security and reliability services for the five-year period from 2020-21 to 2024-25.

Although AEMO has not identified any NSCAS gaps at this stage, the power system is changing rapidly, and operational measures are being relied upon more frequently to help manage voltages during low demand conditions. AEMO expects that the power system will operate close to its limits in some areas and under some conditions.

AEMO will monitor the situation closely, in particular in Queensland and Victoria, and if conditions change then AEMO will declare gaps as required before the next scheduled annual review.

The assessment has revealed emerging operational challenges and opportunities:

- Reducing levels of minimum demand, potentially co-incident between regions, will require flexible operation of elements of the power system and possibly investment in new equipment.
- As increasing new amounts of distributed photovoltaics (PV) are installed, minimum demand is expected to further decline, and together with increasing amounts of variable renewable energy (VRE), these factors are expected to lead to operational changes in synchronous generation in the market, including withdrawals of units in low demand periods, and lower overall synchronous unit commitments outside of peak demand periods. Delivery of voltage management and reactive power support from non-synchronous generators will become more important than it has been in the past.
- New large-scale renewable generation providers may be able to provide significant reactive power support at times of minimum demand on the system.
- The shift of minimum demand to daytime periods is expanding the amount of time over the year that nearly all reactive power absorbing plant is needed to manage network voltages. As a result, challenges are emerging for critical maintenance works on generation and transmission equipment to prepare it for peak load periods such as summer. Low demand periods have traditionally been ideal maintenance windows for generator maintenance, since energy reserves are high. However, these are now periods with very low reactive power reserves, meaning the maintenance windows are closing.
- Some traditional network planning assumptions may no longer be fit for purpose in the context of declining minimum demand. AEMO is investigating whether planning assumptions need to change so that the system is designed to more efficiently maintain reliability and security with manageable operational risks.

This report presents the findings of AEMO's NSCAS review for the five financial years from 2020-21 to 2024-25

The NSCAS framework is one of the mechanisms provided for in the National Electricity Rules (NER) for AEMO to manage power system security and reliability of supply, and is part of the broader joint system planning process between AEMO and the transmission network service providers (TNSPs).

This framework requires that, at least annually, AEMO assesses the system requirements over a five-year period to keep the network operating within minimum acceptable security and reliability requirements, or to relieve network constraints where this maximises net economic benefits to the market. When AEMO identifies an NSCAS gap for a security or reliability need, it will also specify when the gap is forecast to arise. TNSPs are expected to procure services or other solutions to fill the declared gap. If AEMO subsequently considers the

TNSP will not have arrangements in place to address the security or reliability need by the relevant time, AEMO will use reasonable endeavours to acquire the necessary NSCAS itself.

Although AEMO has not identified any NSCAS gaps at this stage, the power system is changing rapidly, and operational measures are being relied upon more frequently to help manage voltages during low demand conditions. AEMO expects that the power system will operate close to its limits in some areas and under some conditions.

Changes that may lead to a gap being declared from early 2021:

- If minimum demand projections are revised lower.
- If operational measures required to maintain system voltages are determined to be too challenging to implement in a real-time environment.
- If, in consultation with TNSPs, it is determined that additional reactive power headroom is required on reactive plant to contribute to system stability.
- If there is insufficient confidence that committed generation that can provide reactive support will be commissioned on time or that new large-scale renewable generation will not contribute to reactive support as expected.
- If AEMO expects that forecast changes to operation of existing power stations and unit availability is accelerating to within the five-year forecast horizon, and that resultant unit availability means reactive services provided by this plant are no longer available during low demand periods to the extent that it could have a material impact on system security.

AEMO will continue to review the situation, in particular for Queensland and Victoria. If at any time as a result of revised assessments AEMO considers there is likely to be an NSCAS gap in the forecast period, AEMO will declare it before the next scheduled annual NSCAS report.

New South Wales

AEMO has not identified an NSCAS gap in New South Wales over the five-year period to 2024-25. AEMO's assessment of any need for reliability and security ancillary services in New South Wales for the period to 2024-25 found that:

- The Powering Sydney's Future project[1], currently under construction, will address existing equipment limitations. It is expected that the local TNSP is planning for voltage management associated with this project.
- After the Liddell Power Station retirement, announced for April 2023, the committed project to expand transfer capacity between Queensland and New South Wales[2] is forecast to improve the ability to manage voltages in northern New South Wales.
- Committed large-scale renewable generation providers are projected to help with managing system voltages under daytime low demand conditions by providing reactive power support.

Queensland

At this time, AEMO is not declaring an NSCAS gap in Queensland over the five-year period to 2024-25. However, a material change in relevant conditions from those assumed in forecasts over the five-year period could create an NSCAS need. AEMO will continue to monitor these conditions and review NSCAS needs, and may need to declare an NSCAS gap from early 2021 should it be necessary to change the associated assumptions.

---

[1] See https://www.transgrid.com.au/what-we-do/projects/current-projects/powering-sydneys-future/.

[2] Expanding Queensland to New South Wales transmission transfer capacity Project, at https://www.aer.gov.au/system/files/AER%20-%20Determination%20-%20Enhancing%20NSW-QLD%20transmission%20transfer%20capacity%20RIT-T%20-%2027%20March%202020.pdf.

The local TNSP, Powerlink, has proposed reactive power support projects in its 2020 Transmission Annual Planning Report (TAPR)[3] with implementation dates for the end of 2023. AEMO anticipates that the proposed projects would create a more robust power system capable of adapting to the changing power system needs by providing additional reactive power support to manage high voltages during periods of low demand.

While the NSCAS assessment found that system security could remain within system limits under forecast daytime periods of low demand and historical levels of overnight/early morning demand, it indicated that voltages could come very close to allowable limits after a credible contingency in low demand periods with few synchronous generating units online. This may require a range of operational measures to be deployed to maintain a secure operating state, including switching a line out of service for voltage management[4].

Further, highly specific tuning of the power system was required in planning studies to maintain a secure voltage profile under low demand conditions, including specific tapping of transmission system and generation transformers and adjustment of set points of generators and static var compensators (SVCs). This degree of tuning of the system could be very challenging in real-life operations.

In early 2021, AEMO will review the concerns noted and operational implications and consult with Powerlink. If this review does not provide confidence in the proposed solutions for real-time operations, or conditions change as outlined above, then AEMO may revise its assessment, potentially including declaring NSCAS gaps.

South Australia

AEMO has not identified an NSCAS gap in South Australia over the five-year period to 2024-25. Studies to date indicate that system security can be maintained during system intact under normal conditions, although voltages could come very close to allowable limits after a credible contingency. In these situations, South Australia will rely on the synchronous condensers currently under construction as well as existing SVCs to manage voltages during periods of low demand.

The local TNSP, ElectraNet, has identified a project in its 2020 TAPR to install up to five reactors[5] to reduce reliance on dynamic reactive power devices such as SVCs at times of low system demand. AEMO understands that ElectraNet plans to commence a Regulatory Investment Test for Transmission (RIT-T) in 2021 to determine the preferred solution to address this identified need. AEMO will continue to monitor these emerging trends.

Tasmania

AEMO has not identified an NSCAS gap in Tasmania over the five-year period to 2024-25. Tasmania has limited forecast change in demand, few expected power system changes in the five-year period, and contracts in place to meet the 2019 system strength and inertia shortfalls[6] which are expected to also help with voltage control and therefore power system security.

Victoria

At this time, AEMO is not declaring an NSCAS gap in Victoria over the five-year period to 2024-25. However, as outlined in this section, the assessment indicates that the system will operate close to limits during low demand periods after a credible contingency.

Victoria currently experiences high voltages during low demand periods. This is presently managed operationally via switching 500 kilovolt (kV) lines out of service to lower voltages, and through deploying an existing non-market ancillary services (NMAS) contract[7] for reactive services. AEMO and AusNet Services are

---

[3] At https://www.powerlink.com.au/sites/default/files/2020-10/Transmission%20Annual%20Planning%20Report%202020%20-%20Full%20report.pdf.

[4] Switching a 275 kilovolt (kV) line for voltage management has taken place historically including in 2020.

[5] At https://www.electranet.com.au/wp-content/uploads/2020/11/2020-ENet-TAPR.pdf.

[6] In November 2019, AEMO declared shortfalls for both inertia and system strength in Tasmania. TasNetworks has addressed these shortfalls by entering into a commercial agreement with Hydro Tasmania for the provision of system strength and inertia services. Although the system strength and inertia services contracts will expire within the five-year period, AEMO will separately cover the treatment of this expiry in the 2020 System Strength and Inertia Report.

[7] 2020 Victorian Annual Planning Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2020/2020-vapr.pdf?la=en.

progressing augmentations to address these issues from 2021, including the installation of reactors at Keilor and Moorabool terminal stations.

While the NSCAS assessment found that system security could be maintained during low demand periods with few synchronous generating units online, it also found that voltages could come very close to allowable limits after a credible contingency during these conditions. A range of operational measures may need to be deployed to maintain a secure operating state, including switching a 500 kV line out of service for voltage management[8], and using the full reactive absorption capability of online 500 kV connected generation during system normal conditions.

Further, highly specific tuning of the power system was required in planning studies to maintain a secure voltage profile under low demand conditions, including specific tapping of transmission system transformers and adjustment of set points of generators and SVCs. This degree of tuning of the system could be very challenging in real-life operations.

In early 2021, AEMO will review the concerns noted and operational implications. If this review does not provide confidence that the proposed solutions are practical in real-time operations, or conditions change as outlined above, then AEMO may revise its assessment, potentially including declaring NSCAS gaps.

Delivering market benefits

AEMO's 2020 NSCAS assessment also considered whether network constraints could be relieved using market benefits ancillary services (MBAS) to maximise net market benefits. AEMO reviewed existing constraints for an intact transmission system (no outages) under classical system normal conditions, where those constraints had a binding impact of at least $50,000, as identified in AEMO's 2019 NEM constraint report summary[9]. This assessment did not identify any NSCAS gaps for maximising market benefits in the NEM.

In its 2021 NSCAS review, AEMO will consider, where appropriate, any constraints nominated by participants as inputs into the market benefits assessment process as well as the consideration of possible future binding constraints in alignment with the updated NSCAS description and quantity procedure. Stakeholders are welcome to provide any input on potential market benefits assessments to planning@aemo.com.au by 26 February 2021.

Impact of reduced minimum demand forecasts on power system security

This NSCAS review has focused on the impact of reducing levels of minimum demand projected across the NEM, as forecast in AEMO's 2020 Electricity Statement of Opportunities (ESOO)[10]. This trend was forecast due to the revised uptake of distributed PV, driven by strong sales figures in 2019, with no apparent slackening throughout 2020 despite the COVID-19 pandemic. By 2025, all NEM regions are expected to experience minimum operational demand during the daytime, rather than night-time periods.

For the purposes of this NSCAS review, the ability to manage voltages within a set range[11] has been a key consideration. When demand on the system is low, transmission lines are lightly loaded. This causes transmission lines to supply reactive power to the system, increasing voltage levels. Voltage levels can therefore rise to the top end of acceptable limits. In addition, when demand is low, fewer generation units may be online or available to provide voltage support.

---

[8] Switching a 500 kV line for voltage management has taken place historically including in 2020.

[9] AEMO. NEM Constraint Report 2019 summary data. 26 August 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2019/nem-constraint-report-2019-summary-data.xlsx.

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

[11] The set range is normally between 0.9 pu or 1.1 pu, unless equipment ratings, distribution system requirements, or contractual arrangements with customers require more restrictive limits, in which case the more restrictive limits are used

AEMO considers a range of measures to manage voltages in real-time operations, including:

- Reactive power support from static equipment (reactors and capacitor banks), dynamic equipment (such as SVCs[12]) and generators.
- Operational measures including changing (or 'tapping') the transformation ratio of power system transformers or de-energising one transmission line per region for voltage control if there is insufficient head room on dynamic reactive equipment or if voltages are expected to be above specified limits after credible contingencies[13].
- Activating any available NMAS contracts for voltage control.

Operational challenges and opportunities are emerging as the power system transitions

As noted above, the NSCAS assessment has revealed emerging operational challenges. These also signal new opportunities as the power system transitions:

- Reducing levels of minimum demand, and periods of low demand and high variable renewable generation coinciding in neighbouring regions, may limit the ability for regions to share excess generation. This may result in curtailment of variable renewable generation, and higher system voltages. To manage this, flexible operation of elements of the system will become very important, including more frequent tapping of transformers, changes to setpoints of generation and SVCs, switching of circuits to reconfigure the system, and possibly investment in new equipment to manage reactive power and voltages on the network.
- As increasing new amounts of distributed PV are installed, minimum demand is expected to further decline, and together with increasing amounts of VRE, these factors are expected to lead to operational changes in synchronous generation in the market, including withdrawals of units in low demand periods, and lower overall synchronous unit commitments outside of peak demand periods. Delivery of voltage management and reactive power support from non-synchronous generators will become more important than it has been in the past. New large-scale renewable generation providers may be able to provide significant reactive power support at times of minimum demand on the system, but certain operational practices may need to be put in place to ensure its provision.

The operational challenges identified in this NSCAS assessment reveal areas where traditional network planning assumptions may not sufficiently account for the impact of changing generation, network and demand dynamics. Key areas for consideration include assumptions about line-switching for voltage management, dynamic reactive reserve requirements, feasibility of practices identified in this assessment in real-time operations, operational risk profiles, and potential for alternative technology solutions.

AEMO will, over the coming months, investigate further what changes may be needed to planning assumptions to appropriately and efficiently address risks to real-time operation.

---

[12] Reactive power devices include static and dynamic reactive devices. Static reactive devices inject or absorb reactive power on the network in order to increase or reduce network voltages to improve network transfers and to manage voltage levels within equipment limits. Dynamic reactive devices include Statcoms, SVCs, generators and synchronous condensers. Dynamic reactive devices automatically adjust their reactive output in real time over a continuous range within a specified voltage bandwidth in response to grid voltage changes.

[13] De-energising transmission lines is only considered if, at the time of the assessment, AEMO and the TNSP have not identified any material adverse system security and reliability issues, as a result of short-term line switching, under any additional credible contingency.

Contents

Tables

Figures

1. Network support and control ancillary services

Network support and control ancillary services (NSCAS)[14] are non-market ancillary services (NMAS) that may be procured by transmission network service providers (TNSPs) (or by AEMO as a last resort) to control active and reactive power flow into or out of an electricity transmission network, to address the following NSCAS needs:

- Maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard[15].
- Maintain or increase power transfer capability of the transmission network to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market[16].

The National Electricity Rules (NER) give TNSPs the primary responsibility for acquiring NSCAS. If AEMO is required to procure NSCAS under its last resort responsibility, it can only do so to meet the first of the NSCAS needs – for power system security and reliability.

At a minimum, at least annually, AEMO will identify any NSCAS need forecast to arise in the next five years. This information is intended to assist TNSPs in their decision-making about the procurement of NSCAS. This document is that NSCAS report[17] which includes, for the period 1 July 2020 to 30 June 2025:

- An assessment that identifies any NSCAS gap for a NEM region.
- The relevant NSCAS trigger date, the date that the NSCAS gap first arises, for any identified NSCAS gap required for power system security and reliability.
- The relevant tender date, the date AEMO would need to act so as to call for offers to acquire NSCAS by the NSCAS trigger date, for any identified NSCAS gap required for power system security and reliability.
- A report on any NSCAS acquired by AEMO (in its last resort procurement capacity) in the previous calendar year.
- Any other information AEMO considers relevant.

1.1 2020 NSCAS description and quantity procedure amendments consultation

AEMO is required to develop and publish an NSCAS description providing a detailed description of each type of NSCAS, and an NSCAS quantity procedure explaining the determination of the location and quantity of each type of NSCAS required, consistent with the requirements in clause 3.11.4 and the Rules consultation process in rule 8.9 of the NER.

[14] The NSCAS definition is in the Chapter 10 Glossary of NER Version 154.

[15] NER Version 154, Clause 3.11.6 (a)(1).

[16] NER Version 154, Clause 3.11.6 (a)(2).

[17] NER Version 154, Clause 5.20.3.

AEMO regarded the previous procedures, developed in 2011, unfit to fulfill the changing needs of the National Electricity Market (NEM), and in June 2020, embarked on a consultation process to update the procedures such that they address the challenges introduced by the energy transition.

Through the consultation process, AEMO amended the NSCAS description to classify the types of NSCAS to reflect the types of NSCAS need, instead of the specific electrical services to be delivered. The new NSCAS types are now classified as reliability and security ancillary services (RSAS) and market benefits ancillary services (MBAS).

AEMO made three key changes to the NSCAS quantity procedure:

- The ability to restore the network to a secure operating state within at most 30 minutes may be considered in RSAS assessments.
- More flexibility in the selection of forward-looking constraints to be assessed in MBAS studies, which can be proposed by participants along with viable, technology-neutral solutions.
- The removal of restrictive NSCAS inputs and assumptions, which have been replaced by key principles.

The procedure was also updated to improve collaboration with TNSPs at the start and finish of the quantity determination process, to discuss detailed inputs and assumptions and study results.

Additionally, the procedure was updated to allow market participants to propose network issues and constraints to be investigated as well as non-network solutions.

The changes made through the stakeholder consultation process, recorded in the draft[18] and final[19] determination reports, resulted in a combined NSCAS description and quantity procedure[20], effective from 1 October 2020. More information is available on the AEMO consultations website[21].

In this report, AEMO applies the newly updated NSCAS procedures to assess NSCAS for each region of the NEM and has also identified a range of emerging trends relevant for power system security and operability.

1.2 Types of NSCAS

Through a consultation process, AEMO redefined the types of NSCAS. The types of NSCAS have been defined according to the needs that would be primarily addressed and are effective from 1 October 2020:

- System reliability and security ancillary service (RSAS):
  - Maintains the power system within acceptable technical parameters, or
  - Increases access to supply such that the NEM can maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard.
- Market benefits ancillary service (MBAS):
  - Maintains or increases the power transfer capability of the transmission network, to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market.

---

[18] AEMO, Network Support and Control Ancillary Services Description and Quantity Procedure Review Final Report and Determinations, August 2020, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/ncas/stage-2/2020-nscas-description-and-quantity-procedure-amendments-draft-report.pdf?la=en.

[19] AEMO, Network Support and Control Ancillary Services Description and Quantity Procedure Review Final Report and Determinations, September 2020, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/ncas/nscas-final-report-and-determination.pdf?la=en.

[20] AEMO, Network Support and Control Ancillary Services Description and Quantity Procedure, September 2020, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/ncas/2020-nscas-description-and-quantity-procedure.pdf?la=en.

[21] See AEMO's closed consultation on Network Support and Control Ancillary Services Description and Quantity Procedure Amendment, December 2020, https://aemo.com.au/en/consultations/current-and-closed-consultations/network-support-and-control-ancillary-services-description-and-quantity-procedure-amendments.

1.3 Summary of NSCAS contracts

AEMO, as National Transmission Planner, had no active NSCAS contracts during 2020. Table 1 highlights the NSCAS service costs accrued over the past five years under contracts previously procured by AEMO as part of its 'last resort' NSCAS function.

Table 1 NSCAS services costs from 2016 to 2020

Facility	NSCAS Service	Size (megavolt-amperes reactive [MVAr])	NSCAS Contract End Date	Annual Cost				
				2015-16	2016-17	2017-18	2018-19	2019-20
Combined Murray and Yass substations	Voltage Control Ancillary Service[A] (VCAS)	800[B]	30 June 2019	$10,055,572	$10,159,498	$10,375,519	$10,572,619	$0
Murray and Tumut power stations	VCAS	1,650[C]	30 June 2018	$171,797	$147,088	$3,842,236	$0	$0

A. NSCAS procured under the previous NSCAS types developed in 2011.
B. The maximum capacity available from this service.
C. The maximum capacity used at any one time over the years shown.

1.4 Inertia and system strength framework

System strength and inertia are critical requirements for a stable and secure power system. 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. A minimum level of inertia is also required in the power system to suppress and slow frequency deviations so that automatic controls can respond to sudden changes in the supply demand balance.

Under the NER, AEMO is responsible for publishing a report on system strength[22] and inertia[23] which includes the inertia and system strength requirements together with any identified gap over a planning horizon of at least five-years. The system strength and inertia reports for 2020 are published in one publication separate from this 2020 NSCAS report[24].

The NER preclude the use of NSCAS to meet an inertia or fault level gap. Inertia and system strength requirements are managed by a separate framework[25] to the NSCAS framework. However, solutions to address system strength and inertia shortfalls may also address NSCAS needs, as the infrastructure involved in addressing system strength or inertia shortfalls might and often does simultaneously provide additional reactive power support or voltage management. Accordingly, the analysis has considered this. For example, the system strength assessment may determine the minimum number of synchronous units required in service for the management of system strength within that region. For studies of low demand periods in this NSCAS assessment, AEMO has assumed this minimum number of synchronous units in service determined in the system strength assessments.

[22] NER Version 154, NER Clause 5.20.7.

[23] NER Version 154, NER Clause 5.20.5.

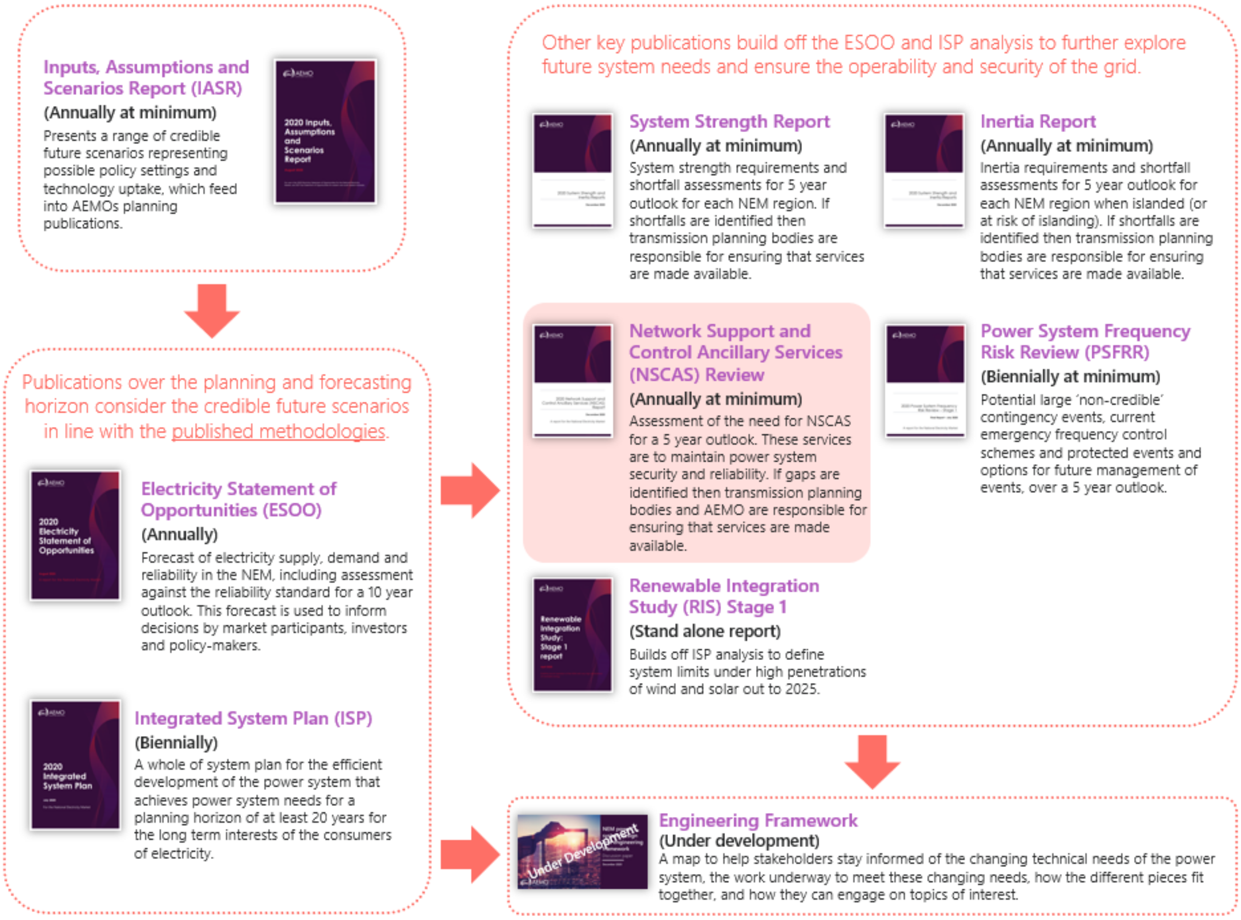
[24] AEMO, System Strength and Inertia Report, December 2020, at www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[25] System Security Market Frameworks Review, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-andreliability/System-Security-Market-Frameworks-Review.

1.5 AEMO's documents on planning for operability

The NSCAS review draws inputs from a number of related reports and processes, and informs and underpins several reports and processes owned by AEMO and TNSPs. Figure 1 shows the NSCAS review in relation to other key AEMO forecasting and planning documents and processes.

Figure 1 Relationship of NSCAS with other AEMO documents and processes



Note: Clicking on an image of a report will take you to that report's location on the AEMO website.

2. Assessing NSCAS

This section explains the broad approach to assessing NSCAS needs, then gives detail on voltage management assumptions and how future electricity demand and supply has been modelled.

Approach to assessing NSCAS needs

To maintain the power system in a secure operating state, the AEMO control room takes operational actions using available options in a hierarchy, with least desirable options used as a last resort. The operational actions AEMO can take are outlined in the Power System Security Guidelines[26]. AEMO NSCAS studies replicate actions taken by the control room to manage system security issues.

During the NSCAS assessment, AEMO worked closely with each TNSP in the NEM to discuss and adjust planning assumptions for each region.

To identify NSCAS needs, in the system security assessment AEMO considers the ability to maintain a secure operating state during system normal conditions. That is, the ability of the system to land in a satisfactory operating state following a credible contingency. On a case by case basis AEMO may assess if the system can be returned to a secure operating state within 30 minutes of a credible contingency or protected event.

Voltage management assessment

The high level of renewable integration experienced in the NEM, and the increasing penetration of distributed photovoltaics (PV), has impacted voltage performance in two ways.

1. Change in operation of generation which may reduce reactive power availability.
2. Reduced operational demand reducing the loading on the high voltage transmission network, resulting in reactive power being created on the transmission lines, leading to high voltages on the network.

High system voltages, particularly during periods of low demand, is an emerging operational challenge and is a focus of this NSCAS assessment. High voltages can lead to equipment damage and cascading failures if no measures are taken to keep them within acceptable voltage ranges.

When assessing voltage needs of the power system in the NSCAS assessment, AEMO considers measures to manage voltages within a set range. The set range is normally between 0.9 pu or 1.1 pu unless equipment ratings, distribution system requirements or contractual arrangements with customers require more restrictive limits, in which case the more restrictive limits are used. Managing voltages within a set range is important for system security. Operating equipment within a system outside its recommended voltage levels can shorten the life of the equipment or result in unstable operation and failure.

The task of regulating voltage involves a combination of constant small adjustments and maintaining a reserve of voltage support services to intervene quickly if there is a disturbance in the power system, so that the system can keep operating securely and safely.

In its NSCAS assessment, AEMO has considered the expected availability and effectiveness of the following actions to control the voltage within the set range in each region:

- Dispatching reactive power from reactive power devices, by either switching in and out of service static reactive devices or controlling the reactive output of dynamic reactive devices[27].

---

[26] Power System Security Guidelines, 23 September 2019 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715---Power-System-Security-Guidelines.pdf.

[27] Static reactive devices include capacitor banks which inject reactive power into the network to boost network voltages and reactors which absorb reactive power from the network in order to reduce network voltages. These devices improve network transfers and manage voltage levels within equipment limits. Dynamic reactive devices include Statcoms, static var compensators (SVCs), generators and synchronous condensers. Dynamic reactive devices automatically adjust their reactive output in real time over a continuous range within a specified voltage bandwidth in response to grid voltage changes.

- Changing the transformation ratio of generation and power system transformers.
- De-energising one transmission line per region for voltage control[28] if there is insufficient head room on static var compensators (SVCs) or if post contingent voltages are above specified limits. This is only considered if AEMO and the TNSP have not identified any material adverse system security and reliability issues, as a result of short-term line switching, under any additional credible contingency.
- Activating any suitable NMAS contracts for voltage control if available.

If the NSCAS assessment indicates that the above operational measures will maintain voltages within the set range, AEMO will not identify an NSCAS gap. However, where transmission line switching is used, TNSPs should investigate operational solutions with consideration of asset performance and market costs and provide alternative cost-effective solutions if required.

Supply and demand side planning for NSCAS in an uncertain environment

Power system security relies on many services that have historically been provided by thermal and hydro synchronous generation. New technologies and approaches to these services are required as the power system continues to transform and becomes increasingly dominated by small and large-scale inverter-based resources.

AEMO forecasts reducing levels of minimum demands across the NEM in its 2020 Electricity Statement of Opportunities (ESOO)[29], released in August 2020. This trend was forecast due to the revised uptake of distributed PV, driven by strong sale figures in 2019, with no apparent slackening throughout 2020 despite the COVID-19 pandemic. By 2025, all NEM regions are expected to experience minimum operational demand during the daytime, rather than night-time periods.

AEMO has considered the potential generation and power system trends in the NEM for the NSCAS assessment by investigating various demand and generation scenarios:

- Demand scenarios:
  - Central[30] demand forecasts for minimum and maximum demand analysis.
  - Central Downside High Distributed Energy Resources (DER) sensitivity was considered for minimum demand analysis to capture more sustained economic downturn and lower manufacturing activity. It also considered a higher distributed PV uptake, possibly stimulated by government recovery efforts.
  - Large industrial load closures.
- Synchronous generators scenarios:
  - Synchronous generation modelled according to announced retirement dates and technical end-of-life dates[31].
  - Minimum system strength and inertia requirements for each region.
  - Capturing the expected change in behaviour of generation.

Although NSCAS gaps are not declared under sensitivities considering forecast change in generation behaviour or large industrial load closures, these sensitivities were conducted to understand what may drive an NSCAS need into the near future.

[28] This operational action is only considered for the management of high voltages on the transmission network.

[29] 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.

[30] These scenarios are further described in the 2020 ESOO and on the AEMO NEM forecasting and planning page, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning.

[31] These assumptions are detailed in other AEMO planning documents, for example the 2020 ESOO and the 2020 Integrated System Plan, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning.

3. NSCAS outcomes for reliability and system security ancillary services

The purpose of the NSCAS assessment is to identify if any region may require NSCAS to maintain the power system within the reliability and system security standards over the five-year period, during system normal and following a credible contingency, under the forecast changes in demand, generation and the transmission network.

This section presents the outcomes of the reliability and system security assessment for the 2020 NSCAS Review conducted for each region for the coming five-year period. Refer to Appendix A1 for the detailed inputs and assumptions.

Given the sharp reduction in minimum demand projections in the 2020 ESOO, AEMO has focused the NSCAS assessment on understanding the impact of this declining minimum demand.

3.1 Emerging trends in the NEM

The NSCAS assessment has revealed operational challenges and opportunities that are emerging as the power system transitions. AEMO will continue to consider and monitor these as part of its ongoing planning assessments and continuous planning approaches, including as part of future NSCAS assessments.

Demand supply balance with declining minimum demand

Reducing levels of minimum demand, and periods of low demand and high variable renewable generation coinciding in neighbouring regions, may limit the ability for regions to share excess generation. This may result in curtailment of variable renewable generation, and higher system voltages.

Under low demand periods there may be a need to keep a minimum number of synchronous generating units online within a region to meet system strength requirements. During daytime low demand periods, solar generation within the region may also be high. Coincident low demand and high solar generation conditions combined with minimum synchronous generation requirements, may result in generation within a region exceeding the regional demand. If high solar and low demand periods coincide between regions, this may limit the ability for regions to share excess generation.

If excess variable renewable generation cannot be exported because neighbouring regions are also at low demand, these generators will not be fully dispatched. Interconnecting lines will become lightly loaded, which further increases system voltages such that voltage management may become a problem.

Options such as flexible generation operation, active distributed energy management, load-shifting, and use of transmission interconnection and energy storage may need to be considered if this trend continues.

Demand projections

Distributed PV uptake for multiple NEM regions appears to be tracking above the 2020 ESOO forecast, and therefore minimum demand levels may in the future be lower than forecast. AEMO regularly updates its demand forecasts. Updated forecasts will consider the latest available information on distributed PV uptake.

AEMO may revisit NSCAS assessments in advance of the next scheduled annual NSCAS review, to consider the impact of any updated demand forecasts.

Currently, the NSCAS assessment considers the forecast minimum demand which is expected to occur during the daytime in all regions. AEMO has identified that although demand at night and early morning may not reach the minimum seen during the middle of the day, challenges could emerge for high voltage situations even at these above-minimum demand times due to the different power factor[32] of night-time demand, and the different availability of generators. AEMO intends to consider this important issue in its future planning assessments.

AEMO recognises that the reactive power profile of the distribution network is changing with declining minimum demand increasing the capacitive effect[33] of the lightly loaded distribution network. In addition, the demand power factor is changing due to uptake of energy efficiency and distributed PV. AEMO will continue to explore this further and adapt assumptions accordingly.

Large industrial load closures

AEMO's 2020 ESOO investigated the broad market dynamics affecting large industrial loads in the NEM, as well as industry-specific opportunities and threats. For the 2020 forecasts, the trend in the Central scenario is for modest increases in electricity consumption for large industrial loads over the 20-year outlook.

Nevertheless, the design and operation of the power system is based not only on supply and location of generation, but also on demand and location of major loads. Depending on the circumstances, if a major industrial load was no longer operational, then this could affect the ability to manage voltages on the system under periods of low demand. Since it is likely there would be little lead time between the announcement and any actual closure, there is a need to continually monitor the risks and to have action plans in place to quickly address any NSCAS needs that may arise should a major industrial load unexpectedly close.

Generation reactive power capability

As periods with low numbers of synchronous generators online increase (for example, during minimum demand periods), delivery of voltage management and reactive power support from non-synchronous generators will become more important than it has been in the past, and delivery of these properties from existing generators will continue to be important.

New large-scale renewable generation providers may need to provide significant reactive power support at periods of low demand to assist in the management of system voltages.

It is essential that AEMO is able to effectively utilise reactive power capability of new and existing generation to maintain secure voltage levels, and it is critical that AEMO can promptly access the full reactive power capability of all online generators when needed to maintain system security. However, the reactive power capability of some generators cannot always be called upon fast enough in operational timeframes. This may be due to difficulties getting in contact with the generators to issue instructions, or delays in their implementation of the instructions.

AEMO has observed changes in the performance of some ageing synchronous generators, including a decline in reactive power capability, which is relevant to assessment of NSCAS needs, and management of voltages and reactive reserves on the power system for system security. Generators are required to meet the levels specified in their registered generator performance standards. AEMO will review changes and/or solutions proposed by generators to confirm that they will continue to meet the standards and do not adversely impact system security.

[32] Power Factor = $P/\sqrt{(P^2 + Q^2)}$, where P = active power, and Q = reactive power. It is a convenient measure of reactive power content of demand, which in turn influences system voltages.

[33] The phenomenon whereby power lines produce reactive power and boost voltages (similar to a capacitor) when transmitting low levels of power.

Operational feasibility and challenges

Historically, it has been assumed that if the network is planned such that it is secure with all elements in service during the most challenging maximum demand and minimum demand periods, then there will naturally be more benign periods in between when maintenance of system equipment can occur while maintaining a secure operating state.

However, the shift of minimum demand to daytime periods is expanding the amount of time over the year that nearly all reactive power absorbing plant is needed to manage network voltages.

As a result, challenges are emerging for critical maintenance works on generation and transmission equipment to prepare it for peak load periods such as summer. Low demand periods have traditionally been ideal maintenance windows for generator maintenance, since energy reserves are high. However, these are now periods with very low reactive power reserves, meaning the maintenance windows are closing.

In some regions, highly specific tapping of network and generator transformers and adjustment of generator and SVC voltage setpoints would be required during the higher-demand periods of the day in order to then later manage high voltages on the network during periods of lower demand. Since low demand periods occur during daytime and overnight/early morning, this would require control rooms to manage four different voltage profiles per day (overnight/early morning low, morning peak, early afternoon low, evening peak), significantly increasing the complexity of voltage management.

This degree of tuning of the system could be very challenging in real-life operational contexts. In 2021, AEMO will investigate further the operational implications. If this review does not provide confidence that the proposed solutions are practical in real-time operations, AEMO may revise its NSCAS assessment, potentially including declaring NSCAS gaps.

Planning assumptions and approaches need to evolve as the power system evolves

This NSCAS assessment has revealed emerging trends where the impact of changing generation, network and demand dynamics may not be sufficiently accounted for under traditional network planning assumptions. This raises questions as to whether planning assumptions applied in the past remain suitable for future planning, to design the power system appropriately for real-time operation. If traditional assumptions need to change, it is necessary to consider what should replace them to facilitate planning that will deliver more efficient management of power system operational risk.

Key areas of concern that AEMO will review early in 2021 are:

- Whether it remains appropriate to assume line-switching for voltage management within planning assessments. Although this practice has been applied operationally, declining minimum demand conditions have required its more frequent application, and the risks associated with its use (particularly its increasing frequency) should be reviewed. This review should inform the appropriate choice of assumptions used in planning assessments.
- Declining minimum demands mean AEMO may need to reconsider assumptions typically used in planning studies about the use of reactive plant at times of minimum demand, particularly the degree of margin which should be retained on the plant to cater for system disturbances.
- Whether some assumptions about operational practices will be practical in real-life system operations at times of extremely low minimum demand, for example highly specific tapping of network and generator transformers, and adjustment of generator and SVC voltage setpoints, to manage different demand conditions within one day.

AEMO will review the key planning assumptions associated with system security and the system operation risk associated with the assumptions. AEMO will consult closely with TNSPs as it progresses this review, and notes that changes to planning assumptions could lead to the declaration of NSCAS gaps within the current five-year horizon.

A need for holistic engineering assessment of changing dynamics

In general, there are a number of opportunities that can be explored to appropriately adapt the system to manage the changing generation and demand dynamics for system security in an efficient manner. The focus to date in Australia has largely concentrated on energy and capacity, but the NEM has now reached the point where system security needs and services are more determinant to future design and operation.

There are a range of longer-term measures underway to adapt to these emerging challenges, including the Energy Security Board's post-2025 NEM review[34], and a range of ongoing Australian Energy Market Commission (AEMC) reviews and rule change processes.

AEMO considers that there is a growing need for broader industry discussion to develop[35]:

- Coordinated approaches across system strength, inertia, voltage, reactive, and thermal limit services.
- Improved contingency planning for rapid changes (such as sudden closure of industrial loads).
- Uplift of outage management for reactive plant.
- Opportunities for distributed energy resources to provide reactive support.

3.2 New South Wales

AEMO has not identified an NSCAS gap in New South Wales with the forecast demand and committed projects over the five-year period. The committed Powering Sydney's Future project and minor upgrades to the Queensland – New South Wales Interconnector (QNI) are essential to maintaining system security and reliability.

Recent operational developments

In 2020 there were several periods of low demand in Victoria and New South Wales, with high transfers from Victoria to New South Wales that caused simultaneous high and low post-contingent voltage alarms. The interconnector was constrained using discretionary constraints to resolve the alarms in real time. The V^^N_NIL_1[36] constraint was updated in October 2020. This constraint will limit the interconnector flow before simultaneous high and low post-contingent voltages become a problem in future. AEMO will continue to monitor the performance and binding of this constraint.

Network trends over the NSCAS period

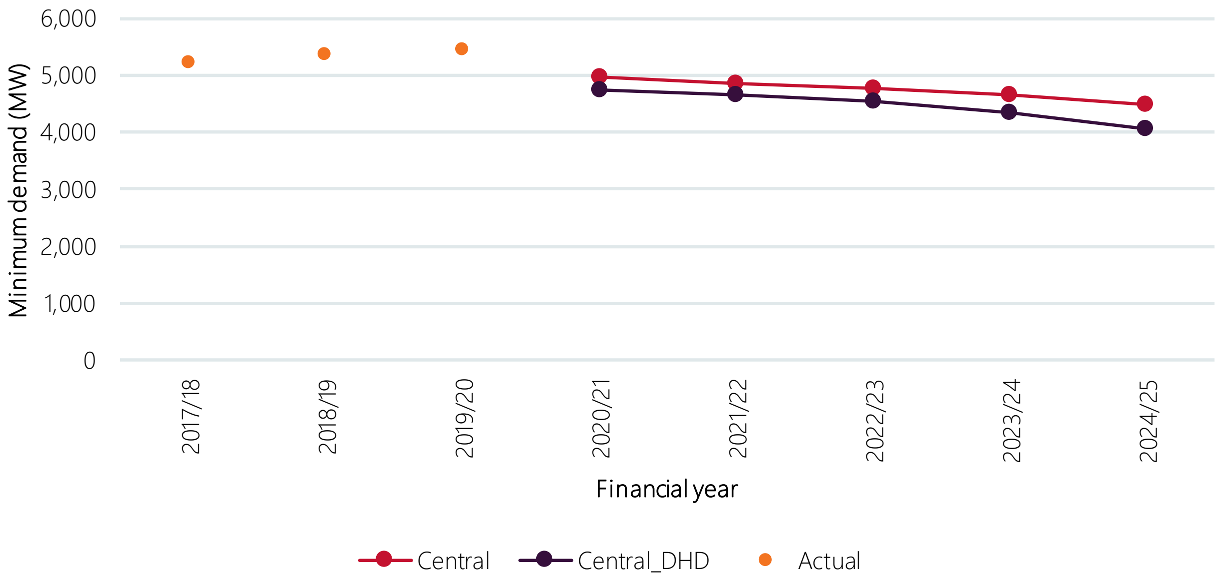
The minimum operational (grid) demand is expected to occur during the summer season, in the middle of the day, with high levels of solar renewable energy generation. The forecast minimum demand for New South Wales is initially expected to decline due to the impact of COVID-19. In the absence of any market-based solutions to increase system load, minimum demand forecasts then continue to decline as distributed PV generation, at time of minimum demand, increases. Under some conditions, minimum demand in New South Wales is projected to fall to 4,069 megawatts (MW) over the five-year NSCAS period, a 14% decline, for the ESOO Central Downside High DER sensitivity as seen in Figure 2.

[34] Energy Security Board Electricity Design Project at https://esb-post2025-market-design.aemc.gov.au/.

[35] AEMO's Engineering Framework will explore this more; see https://www.aemo.com.au/initiatives/major-programs/engineering-framework.

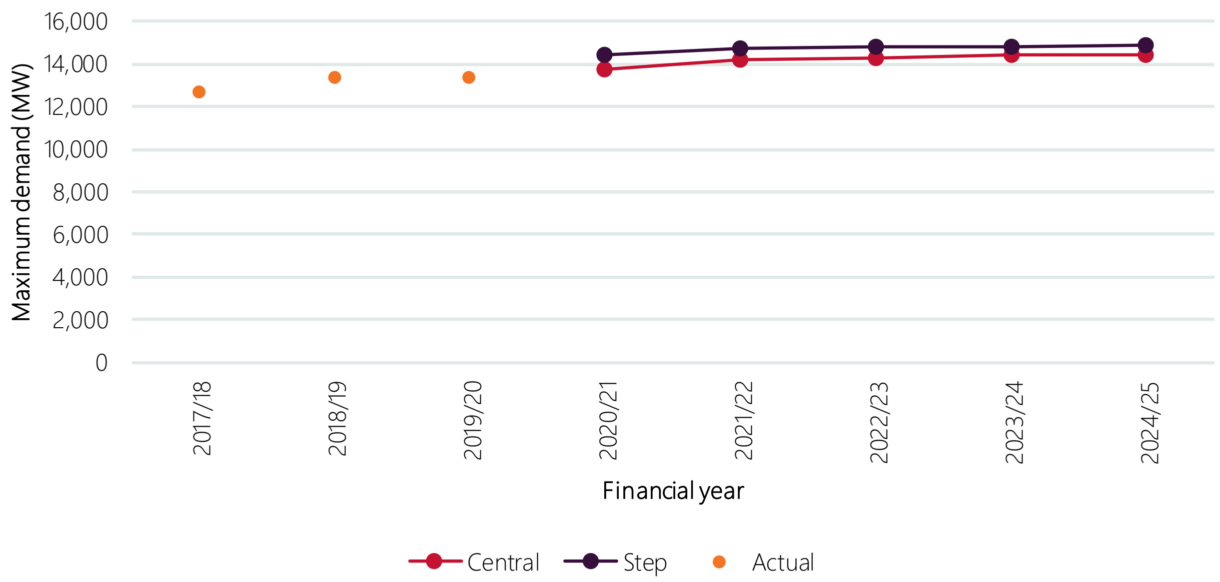
[36] Victorian export constraint to avoid voltage collapse around Murray following contingency interruption of supply to the Alcoa Portland facility.

Figure 2 **Actual minimum and 2020 ESOO forecast 90% POE summer minimum operational demand (sent-out) for New South Wales (Central scenario and Central Downside High DER sensitivity)**



The maximum operational demand is expected to decline in the first year and then recover and remain relatively flat, driven by COVID-19 and the impact of large industrial load (LIL) demand on underlying consumption. The 10% probability of exceedance (POE) forecast maximum demand is projected to peak at 14,889 MW, over the five-year period, a 5% increase, for the Step Change scenario as seen in Figure 3.

Figure 3 **Actual maximum and 2020 ESOO forecast 10% POE summer maximum operational demand (sent-out) for New South Wales (Central and Step Change scenarios)**



As at July 2020, there are two in-commissioning and 10 committed renewable energy generation projects[37], with an installed capacity of approximately 1,760 MW, expected to connect to the New South Wales network

[37] NEM Generation Information July 2020, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

over the next five years. Solar represents approximately 70% of these new connections and is expected to provide dynamic reactive support on the network during daytime minimum demand.

There are two committed transmission projects that impact the outcomes of the NSCAS assessment; these projects were included in the assessments:

- Powering Sydney's Future to improve the security and reliability of inner Sydney's electricity network.
- Expanding New South Wales to Queensland Transmission Transfer Capacity[38] to increase power transfer between New South Wales and Queensland during high demand periods. This project also provides dynamic reactive power support during low demand periods.

System security and reliability assessment outcomes

AEMO has not identified an NSCAS gap in New South Wales over the five-year period. AEMO determined that system security and reliability can be maintained in New South Wales over the NSCAS horizon under 1-in-10 year forecast demand conditions, and with committed projects.

The NSCAS assessment found that after the staged Liddell retirement, announced for April 2022 through to April 2023, the committed QNI project to expand transfer capacity between New South Wales and Queensland, will improve reliability and the ability to manage voltages in northern New South Wales by creating additional reactive power reserve on the network.

The committed Powering Sydney's Future project will see the development of a new 20 km, 330 kilovolts (kV) cable between the existing Rookwood Road and Beaconsfield substations. The project caters for future electricity demand growth and is currently under construction. The project will also improve system security and reliability by removing restrictive equipment voltage limits in the Sydney region. AEMO expects that the local TNSP is planning for voltage management associated with this project.

The inclusion of reactive power support provided by remotely located variable renewable energy (VRE) plants in regional and central New South Wales assists in managing voltages by providing dynamic reactive support when operating in voltage control mode.

3.3 Queensland

AEMO is not yet declaring an NSCAS gap in Queensland over the five-year period, but is closely monitoring changing system conditions that may trigger a gap declaration from early 2021. While AEMO's current assessment is that system security can be maintained under ideal conditions, during low demand periods with few synchronous generating units online, post-contingent voltages could come very close to allowable limits in future years, and AEMO is reviewing operational risks.

Recent operational developments

On 8 and 10 November 2020, AEMO switched two 275 kV transmission lines out of service for voltage control in southern Queensland during periods of low demand. Prior to switching the Tarong–Blackwall and Middle Ridge–Greenbank 275 kV lines out of service, the Greenbank SVC was absorbing reactive power close to its reactive limits.

These lines were switched out of service during an early morning period when the sent-out demand was between 4,750 MW and 5,100 MW, over 1,000 MW above the minimum demand level recorded in Queensland to date (3,604 MW). Five synchronous units were in service in southern Queensland, the Queensland to New South Wales interconnector was operating close to 0 MW, and reactive support provided by nearby generators was also limited at the time due to technical issues.

[38] See https://www.aer.gov.au/system/files/AER%20-%20Determination%20-%20Enhancing%20NSW-QLD%20transmission%20transfer%20capacity%20RIT-T%20-%2027%20March%202020.pdf.

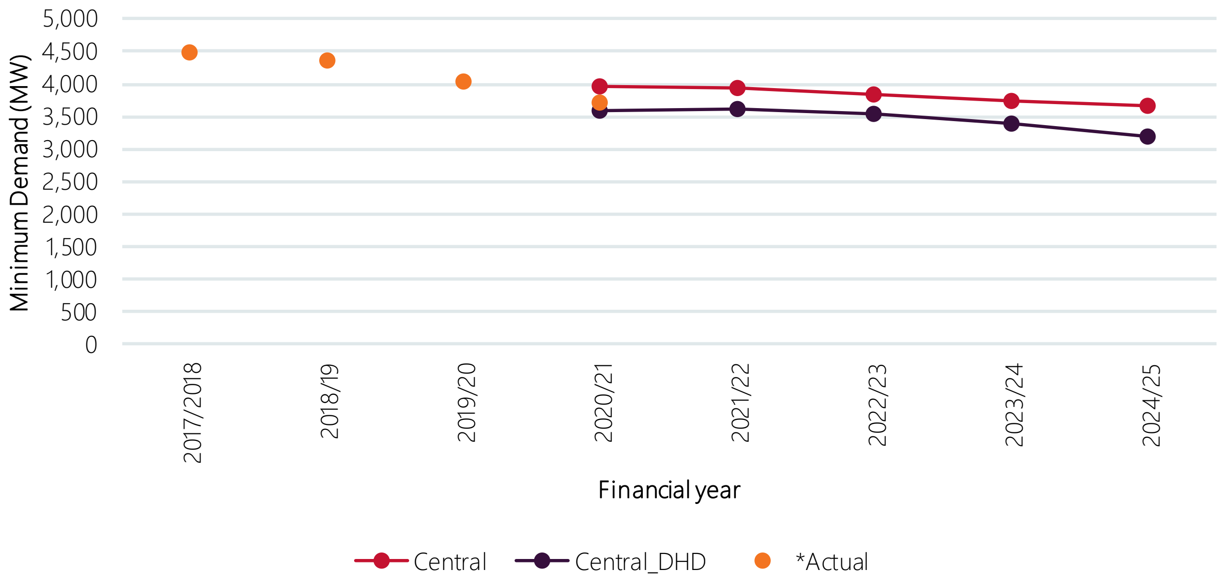
AEMO has identified that, although demand at night and early morning may not reach the minimum seen during the middle of the day, challenges could emerge for high voltage situations even at these above-minimum demand times, due to the different power factor of night-time demand and the different availability of generators. AEMO will continue to investigate these issues.

Network trends over the next five years

Minimum operational demand (90% POE) for Queensland is forecast to decrease by approximately 9% under the 2020 ESOO Central scenario and by 12% under the Central Downside High DER sensitivity between 2020 and 2025, as seen in Figure 4. The minimum demand for Queensland generally occurs in the late morning and middle of the day and this is expected to continue across the forecast horizon.

Between August and September 2020, new minimum demand records occurred in Queensland, with the lowest record of 3,604 MW as sent-out (3,860 MW as-generated) occurring on 27 September 2020. These minimum demand records occurred during the daytime at around midday.

Figure 4 Actual minimum and 2020 ESOO forecast 90% POE shoulder minimum operational demand (sent-out) for Queensland (Central scenario and Central downside high DER sensitivity)



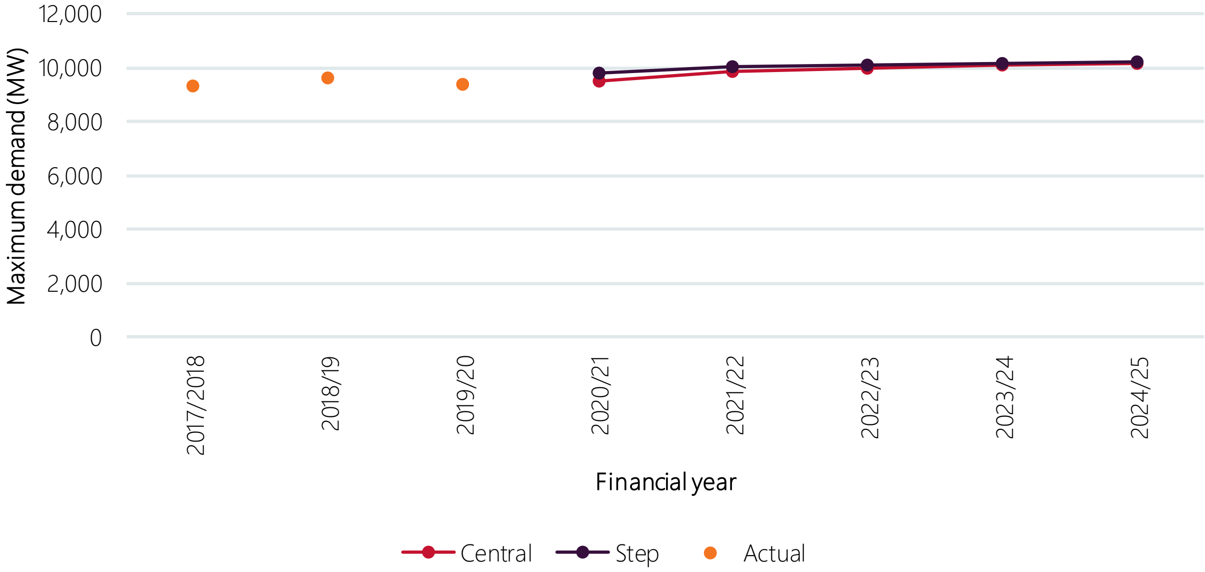
* Record minimum demand occurred 27 September 2020 and has been included in the 2020-21 financial year actual; 2020-21 has been included as an actual despite it being an incomplete year.

The 10% POE maximum operational demand in Queensland is forecast to increase by 4% and 6.5% respectively for the Central and Step Change scenarios over the NSCAS period, as seen in Figure 5.

As at July 2020, there are six committed renewable energy generation projects[39], with a capacity of approximately 300 MW. Most of these projects are solar farms, which have the potential to assist in managing voltages under daytime low demand periods through provision of dynamic reactive support, provided suitable equipment is installed in the development.

[39] This includes committed* projects according to the NEM Generation Information July 2020, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Commitment criteria are explained under the Background Information tab.

Figure 5 Actual maximum and 2020 ESOO forecast 10% POE summer maximum operational demand (sent-out) for Queensland (Central and Step Change scenarios)



System security and reliability outcomes

At this time, AEMO has not identified an NSCAS gap in Queensland over the five-year period. However, a material change in relevant conditions from those assumed in forecasts over the five-year period could create an NSCAS need. AEMO will continue to monitor and review these conditions, and may need to declare an NSCAS gap from early 2021 should it be necessary to change the associated assumptions.

Distributed PV uptake for Queensland is tracking above the 2020 ESOO forecast, therefore minimum demand levels may be lower than forecast in the future. Appendix A2 presents early results of ongoing studies examining the possible outcomes and requirements for different demand forecasts, including extreme cases. These studies are ongoing.

Under the planning assumptions, this assessment indicates that system security can be maintained under forecast periods of daytime low demand, and historical levels of overnight/early morning demand[40]. However, during low demand periods with few synchronous generating units online, post-contingent voltages could come very close to allowable limits in future years.

In this NSCAS assessment, requirements to maintain post-contingent voltages below maximum allowable levels during minimum demand included the following:

- Switching one 275 kV transmission line out of service (Blackwall–Tarong).
- New committed generation contributing to reactive power support.
- Close to the full reactive absorption capability of generators within Southern Queensland, used pre-contingency.
- Careful tapping of 330/275 kV, 275/110 kV, and generating unit transformers in Southern Queensland, to manage the voltage profile.
- In addition, significant new generation commitments could provide additional reactive power support and prevent the need to declare a gap.

[40] Overnight/early morning conditions were assessed by studying a scenario with the demand that occurred at 06:30 on 8 November 2020, and with four South East Queensland synchronous generating units online.

To maintain post-contingent voltages on the transmission network below 1.1 pu, the lower voltage networks are operated close to the upper bound of 1.1 pu. This may lead to difficulties in managing voltages on the distribution network, and the feasibility of this will need to be examined further.

Given indications that the Queensland power system could operate very close to system security limits, even with these measures available, AEMO also studied whether the Queensland transmission network could be returned to a secure operating state within 30 minutes of trip of an SVC in southern Queensland.

Studies indicate that up until 2023-24, there is still capability to achieve this recovery timeframe following an SVC trip. However, from 2024-25, at forecast minimum demand and under low synchronous generation dispatch patterns[41], it would be necessary to direct a synchronous generator in southern Queensland online within 30 minutes of the trip to return the network to a secure operating state. This outcome is based on current committed generation projects; any new variable renewable generation that subsequently becomes committed and is in service by 2024-25 may provide reactive support and reduce the need to rely on directions. AEMO will continue to monitor this condition.

Highly specific tapping of generator transformers and adjustment of generator and SVC voltage setpoints must begin during the intervening higher demand periods to ensure voltages can be kept as low as possible before an overnight/early morning or early afternoon low demand period. This requires control rooms to manage four voltage profiles per day (overnight/early morning low, morning peak, early afternoon low, evening peak), significantly increasing the complexity of voltage management. This degree of tuning of the system could be very challenging in real-life operations. In 2021, AEMO will review further these planning assumptions.

The conditions that could lead to AEMO declaring an NSCAS gap in Queensland include the following:

- If minimum demand projections are revised lower.
- If operational measures required to maintain system voltages are determined to be too challenging to implement in a real-time environment.
- If, in consultation with Powerlink, it is determined that additional reactive power headroom is required on reactive plant to contribute to system stability.
- If there is insufficient confidence that committed generation that can provide reactive support will be commissioned on time, or that new large-scale renewable generation will not contribute to reactive support as expected.
- If AEMO expects that forecast changes to existing power station operation and unit availability is accelerating to within the five-year forecast horizon, resulting in further reductions in reactive support provided by this plant during low demand periods that could have a material impact on system security.

In early 2021, AEMO will review the concerns noted and consult with Powerlink. If this review does not provide confidence in the proposed solutions for real-time operations, or conditions change as outlined above, then AEMO may revise its assessment, potentially including declaring NSCAS gaps.

Proposed reactive support to manage high voltages in Queensland

Powerlink has proposed reactive support projects in its 2020 Transmission Annual Planning Report (TAPR)[42] with implementation dates for the end of 2023.

Powerlink published the Project Specification Consultation Report (PSCR) for managing voltage control in Central Queensland on 8 October 2020. Powerlink notes that switching lines out of service in this region would be difficult, as it would reduce system strength on the network, which would constrain variable renewable energy generation in North Queensland. This project proposes three solutions with the installation of a 150 megavolt-amperes (MVAr) 300 kV busbar reactor at Broadsound substation presenting the highest net economic benefit to customers. The proposed project timing is for installation by June 2023.

[41] Aligned with one or more of the minimum acceptable combinations of synchronous machines for southern Queensland.

[42] At https://www.Powerlink.com.au/sites/default/files/2020-10/Transmission%20Annual%20Planning%20Report%202020%20-%20Full%20report.pdf.

Powerlink, in its 2020 TAPR, also identified a need for additional reactive support in south east Queensland to maintain voltages within operational and design limits during minimum demand periods, and to reduce system strength impacts from the de-energisation of transmission lines. The proposed project includes the installation of three busbar reactors at various locations in south east Queensland by December 2023.

The proposed projects are expected to create a more robust power system capable of adapting to the changing power system needs by providing additional reactive support to manage high voltages during periods of low demand.

3.4 South Australia

AEMO has not identified an NSCAS gap in South Australia over the five-year period. Studies to date indicate that system security can be maintained, although post-contingent voltages are forecast to come close to allowable limits with a reliance on synchronous condensers and SVCs to manage voltages during periods of low demand

Committed system security solutions

AEMO, since 2018, has been regularly directing synchronous units online in South Australia to manage system strength gaps. On 13 September 2017, under the NSCAS framework, a system strength gap was identified for South Australia. TNSP ElectraNet elected to meet the NSCAS gap as a fault level shortfall under the new system strength framework introduced by the AEMC in September 2017. In addition, an inertia shortfall was declared in South Australia in the 2018 National Transmission Network Development Plan[43].

ElectraNet is installing synchronous condensers, fitted with flywheels, at Davenport and Robertstown substations in 2021. These synchronous condensers will provide system strength and inertia which will reduce the respective shortfalls. In addition to providing system strength and inertia, these synchronous condensers will provide dynamic reactive support to assist in managing system voltages on the South Australian transmission system.

Current operational challenges

On 19 July 2020, one of the SVCs at Para experienced a forced outage, with an expected return to service date in mid-2021. The primary impact of the outage is that flows from South Australia to Victoria on the Heywood interconnector have since been restricted to 420 MW.

In addition to the limitations on the Heywood interconnector, the outage of this Para SVC has impacted the management of voltages on the South Australian network under periods of low demand. On two occasions, under periods of low demand, the East Terrace – Magill 275 kV cable has been switched out of service for voltage control. This demonstrates the network's reliance on the availability of all reactive equipment to manage voltages in periods of low demand.

Network trends over the next five years

South Australia has experienced a minimum operational demand in the middle of the day since 2012-13, and this is forecast to continue. Minimum operational demand typically occurs during weekends or public holidays when demand is low, temperatures are mild, and around noon when distributed PV reduces the need for grid-delivered energy.

A new record low minimum demand of 290 MW sent-out (300 MW as-generated) was set on Sunday, 11 October 2020. The minimum demand is more than 150 MW less than the minimum demand recorded in 2019-20. The plots in Figure 6 indicate that the actual minimum demand for South Australia to date for 2020-21 represents a trend close to the more extreme Central Downside High DER sensitivity in the 2020 ESOO, largely due to higher distributed PV uptake than forecast in the 2020 ESOO Central scenario.

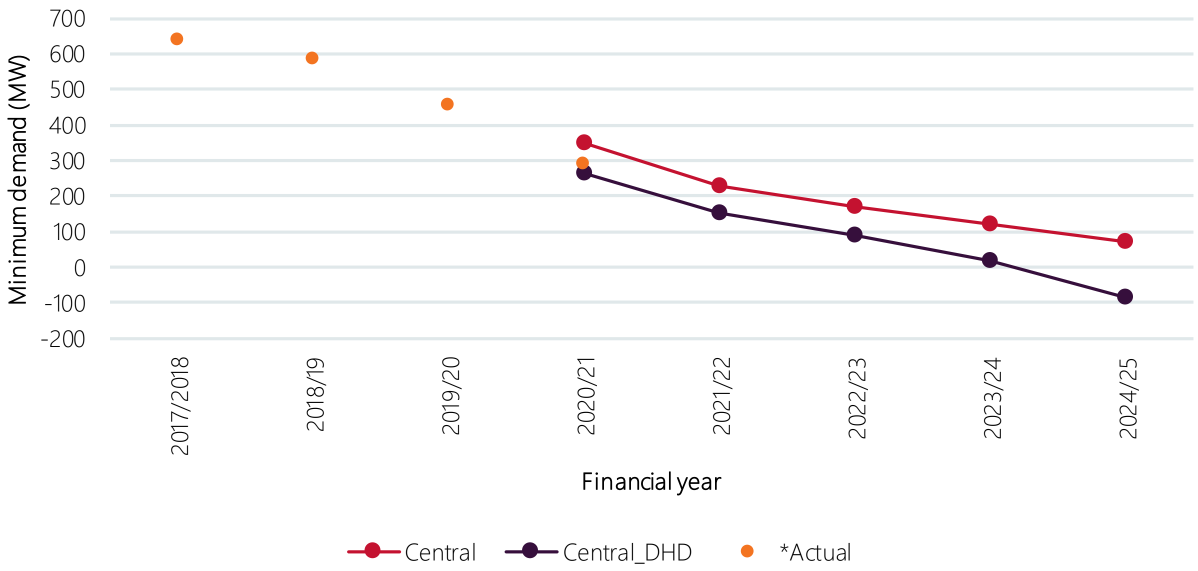
---

[43] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2018/2018-ntndp.pdf.

Figure 6 shows that the 2020 ESOO forecasts a significant decline in 90% POE shoulder[44] minimum demand in the Central scenario from 2020-21 to 2021-22, due to the forecast increase in distributed PV installations, then a more gradual decline in the following years to reach a minimum sent-out demand of 72 MW by 2024-25. The slower decline post 2022-23 is due to a forecast lower rate of distributed PV installations. The Home Battery Scheme from the South Australian Government is forecast to slightly reduce the impact of high distributed PV installations on minimum operational demand.

The Central Downside High DER sensitivity also forecasts a steep decline from 2020-21 to 2021-22 and again from 2023-24 to 2024-25 to reach a minimum sent-out demand of -84 MW.

Figure 6 Actual minimum and 2020 ESOO forecast 90% POE shoulder minimum operational demand (sent-out) South Australia (Central scenario and Central Downside High DER sensitivity)



* Record minimum demand occurred 11 October 2020 and has been included in the 2020-21 financial year actual; 2020-21 has been included as an actual despite it being an incomplete year.

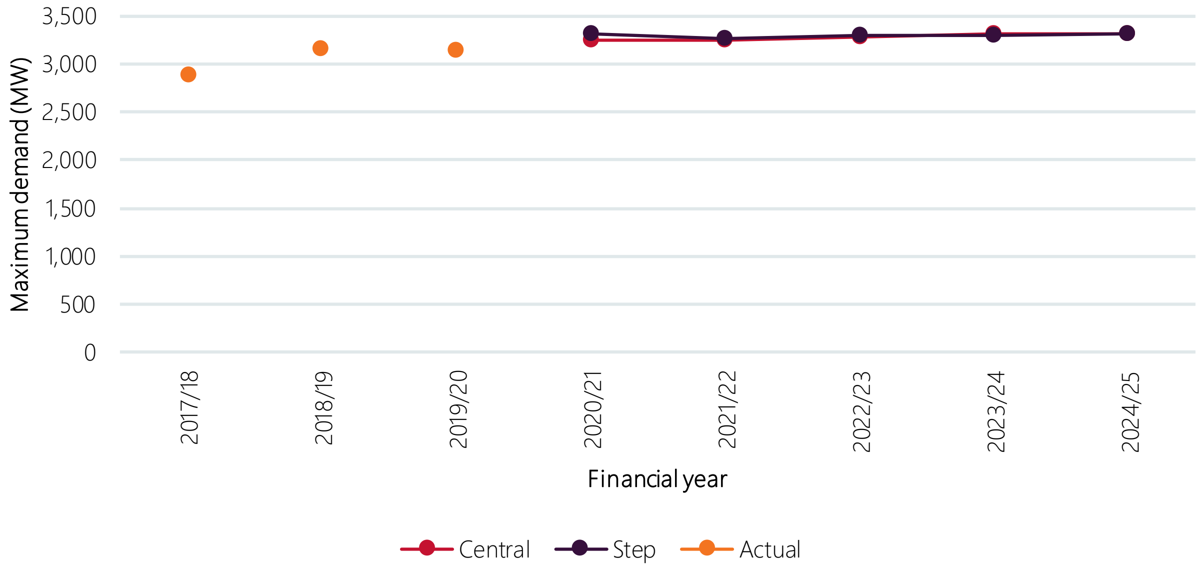
The maximum 10% POE operational demand for South Australia is forecast to decline in the first year driven by COVID-19, then to grow slightly as the economy recovers, as seen in Figure 7.

Although maximum demand is not forecast to change significantly over the five-year period, Torrens A and Osborne power station retirements within the NSCAS review period can impact the outcomes of the security and reliability assessment.

In the NSCAS assessment, AEMO considered the announced retirements when analysing whether voltage control provided by the synchronous condensers and other committed transmission projects would be adequate to manage the system voltage needs under the forecast 1-in-10 year minimum and maximum demand, with changes in generation outlook over the next five years.

[44] The shoulder period refers to September, October, April and May months.

Figure 7 **Actual maximum and 2020 ESOO forecast 10% POE summer maximum operational demand (sent-out) for South Australia (Central and Step Change scenarios)**



System security and reliability assessment outcomes

AEMO has not identified an NSCAS gap in South Australia over the five-year period.

Under periods of high demand, AEMO does not identify challenges with managing voltages with available reactive support.

Studies to date indicate that system security can be maintained during system normal and for a credible contingency event, although post-contingent voltages are forecast to come close to allowable limits with a reliance on the availability of ElectraNet's synchronous condensers and SVCs to manage voltages during periods of low demand.

Additional challenges for reactive power and voltage control include the number of synchronous generators online during low demand periods with very high distributed PV in South Australia. Analysis is ongoing by AEMO and ElectraNet under other frameworks to address frequency control, system strength, and inertia challenges. Resolution of these challenges may also assist in managing voltages in South Australia.

Proposed reactive support projects in South Australia

ElectraNet has identified, in its 2020 TAPR, a project to install up to five 50 MVAr 275 kV reactors[45] at various locations to address an emerging need to reduce reliance on dynamic reactive power devices to satisfactorily manage voltages at times of low system demand. ElectraNet plans to commence a Regulatory Investment Test for Transmission (RIT-T) in 2021 to determine the preferred solution to address the identified need subject to confirming the need for this project. AEMO will continue to monitor the emerging trends and the proposed solutions.

3.5 Tasmania

AEMO has not identified any NSCAS gap in Tasmania over the five-year period, provided requirements for contracting of system strength and inertia services continue.

[45] At https://www.electranet.com.au/wp-content/uploads/2020/11/2020-ENet-TAPR.pdf.

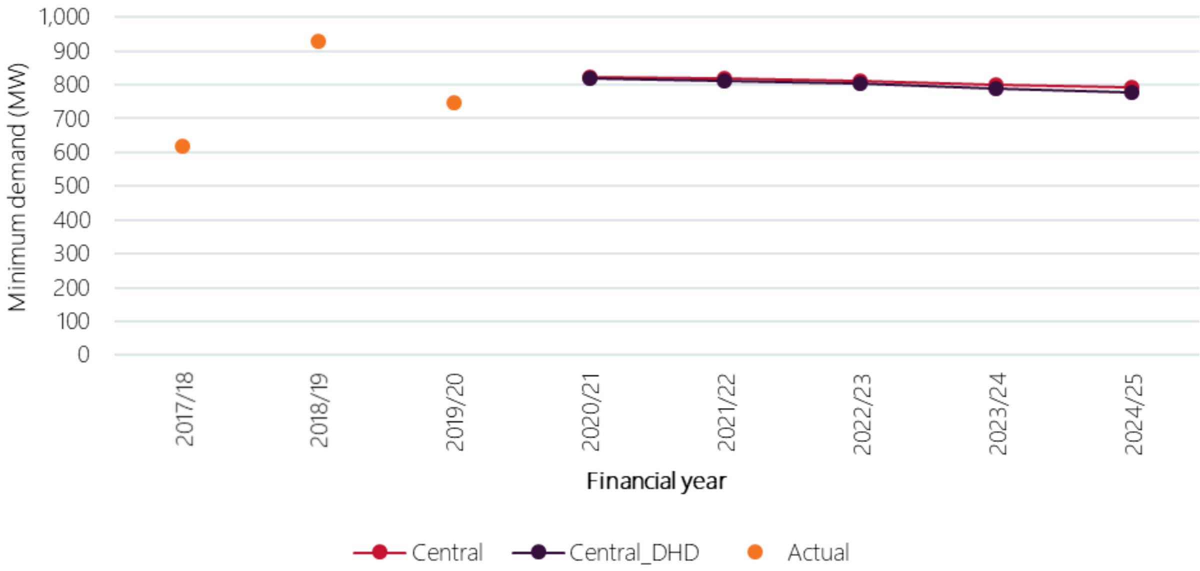
Recent operational developments

In November 2019, AEMO declared shortfalls for both inertia and system strength in Tasmania[46]. This declaration set out the requirements to maintain the power system security and system standards in Tasmania. These shortfalls have been addressed by TNSP TasNetworks entering into a commercial agreement with Hydro Tasmania for the provision of system strength and inertia services. The current agreement expires in 2024. These units also provide reactive support and voltage control for Tasmania.

Network trends over next five years

The minimum 90% POE operational demand for Tasmania is projected in the 2020 ESOO to remain relatively flat over the five-year period, as seen in Figure 8, with minimal difference in demand between the Central scenario and the Central Downside High DER sensitivity. AEMO's forecasts indicate minimal growth in distributed PV in Tasmania and suggest that minimum demand levels are not likely to reduce significantly over the five-year period.

Figure 8 Actual minimum and 2020 ESOO forecast 90% POE summer minimum operational demand (sent-out) for Tasmania (Central scenario and Central Downside High DER sensitivity)



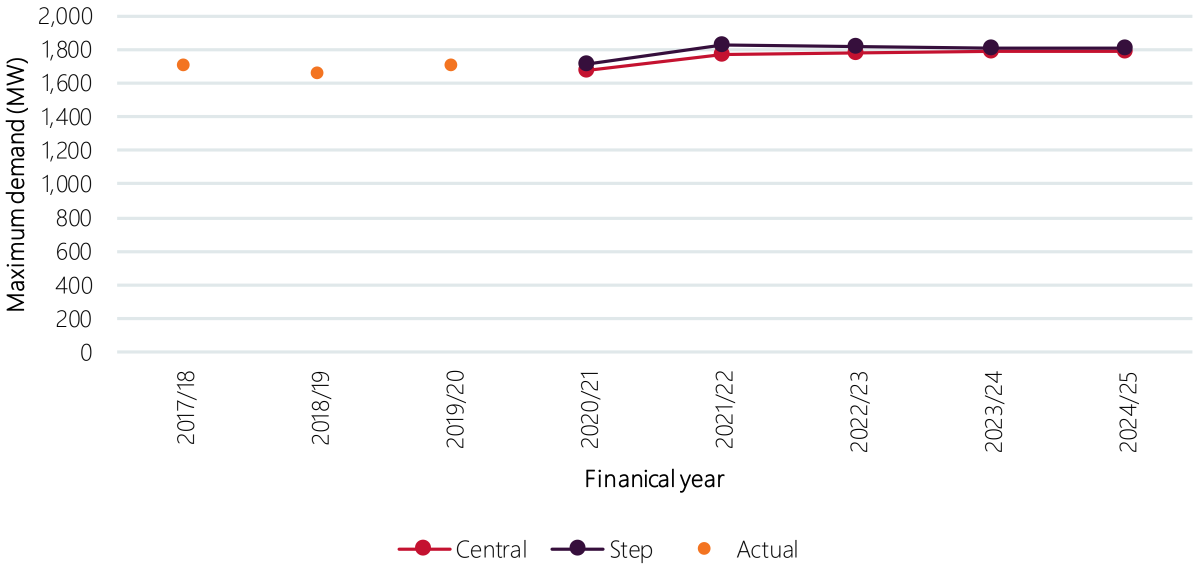
The maximum 10% POE operational demand forecast for Tasmania is initially expected to increase in 2021-22, driven by LIL returning towards previous levels, then generally remaining flat. Maximum demand occurs in the winter months driven by residential heating load.

Figure 9 shows the maximum demand projections for Tasmania for the Central and Step Change scenarios. AEMO did not conduct maximum demand analysis for its NSCAS assessment, as there are no drivers forecast over the next five years that would make maintaining secure voltage levels during maximum demand more challenging than at present.

Granville Harbour and Cattle Hill wind farms are currently in commissioning, with full commercial use expected in December 2020 and February 2021 respectively. This increases the inverter-based generation in Tasmania by approximately 260 MW. There are no other committed generation projects or announced generation retirements in Tasmania during the NSCAS period.

[46] Notice of inertia and fault level shortfalls in Tasmania, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

Figure 9 **Actual maximum and 2020 ESOO forecast 10% POE winter maximum operational demand (sent-out) for Tasmania (Central and Step Change scenarios)**



System security and reliability assessment outcomes

AEMO has not identified an NSCAS gap in Tasmania over the five-year period.

In the NSCAS assessment, AEMO assumed the system strength and inertia contract with Hydro Tasmania will be available to manage system strength and inertia shortfalls declared in 2019 in Tasmania until at least June 2024. This arrangement requires a minimum number of synchronous units in service under low demand periods, which also provide voltage support on the network. The Tasmania NSCAS need may change if there are different solutions to address the system strength and inertia shortfalls from 2024.

Given the forecast system conditions in the next five years, including minimal projected change in forecast demand, no committed generation projects[47], system strength and inertia contracts and no announced or anticipated generation retirements, AEMO's assessment is that system security and reliability in Tasmania could be maintained without the need for additional NSCAS.

AEMO will monitor this development and reassess the Tasmanian NSCAS need once the system strength and inertia solutions have been identified.

3.6 Victoria

AEMO is not yet declaring an NSCAS gap in Victoria over the five-year period but is closely monitoring changing system conditions that may trigger a need for a gap declaration from early 2021. While AEMO's current assessment is that system security can be maintained under ideal conditions, during low demand periods with few synchronous generating units online, post-contingent voltages could come very close to allowable limits in future years, and AEMO is reviewing operational risks.

Current operational challenges

Victoria experiences high voltages during low demand periods. The worst affected areas are at present around Geelong, Keilor, Moorabool, and South Morang. This is currently managed operationally via the switching of 500 kV lines and an NMAS contract.

[47] AEMO has not included the impacts of the Tasmanian Renewable Energy Target legislation in this analysis, due to timing constraints.

AEMO is responsible for planning and directing augmentation on the Victorian electricity transmission declared shared network. In 2019, AEMO entered into an NMAS contract agreement for additional reactive support from a generator, which is called on as needed to manage post-contingent high voltages.

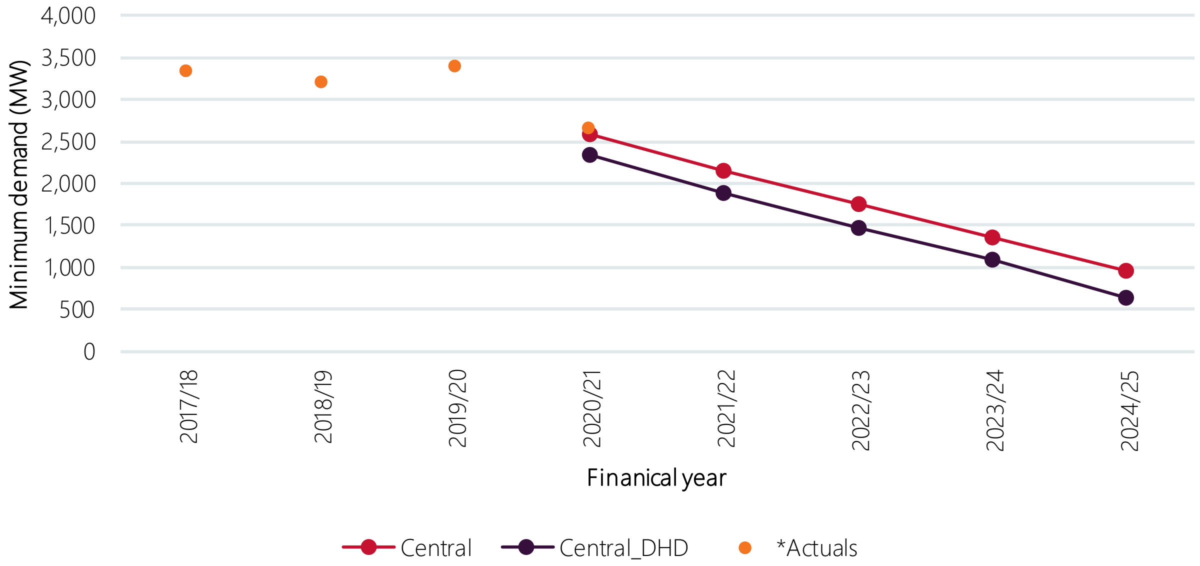
Managing high voltages during low demand periods has become more challenging as minimum demand has continued to decline during 2020. At times, in addition to the NMAS contract capability, AEMO has been forced to switch out of service two 500 kV lines as a last resort to keep post-contingent voltages below maximum allowable levels.

AEMO and TNSP AusNet Services have progressed planned augmentations to address these issues from 2021, namely the installation of reactors at Keilor and Moorabool substations.

Network trends over the next five years

A new record low minimum operational demand of 2,606 MW sent-out (2,828 MW as-generated) was set on Sunday, 1 November 2020. This is consistent with the Central scenario forecast in the 2020 ESOO. The Victorian 90% POE minimum operational demand is forecast to decline significantly over the next five years, as shown in Figure 10. This will raise the voltage profile of the network, increasing existing challenges in keeping voltages below allowable maximum levels, during low demand periods.

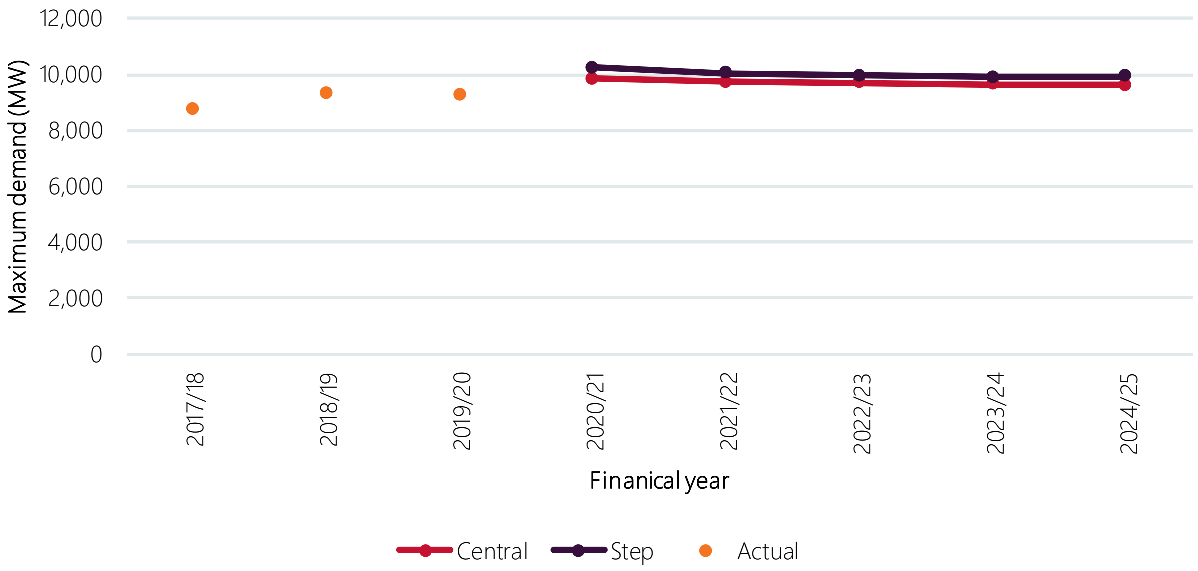
Figure 10 Actual minimum and 2020 ESOO forecast 90% POE shoulder minimum operational demand (sent-out) for Victoria (Central scenario and Central Downside High DER sensitivity)



* Record minimum demand occurred 1 November 2020 and has been included in the 2020-21 financial year actual; 2020-21 has been included as an actual despite it being an incomplete year.

Victorian 10% POE maximum demand is forecast to decline slightly over the next five years, as shown in Figure 11. AEMO did not conduct maximum demand analysis, as there are no drivers forecast over the next five years that would make maintaining security and reliability during maximum demand more challenging than at present.

Figure 11 Actual maximum and 2020 ESOO forecast 10% POE summer maximum operational demand (sent-out) for Victoria (Central and Step Change scenarios)



Network augmentations are planned over the next five years to assist in managing high voltages during low demand periods. These consist of four 100 MVAr reactors, two at Keilor and two at Moorabool.

As at July 2020, there are nine committed renewable energy generation projects[48] and one committed battery, with a total capacity greater than 1,700 MW, expected to connect to the Victorian network over the next five years. These new generators will bring additional reactive absorption capability to the network which is expected to assist in managing high voltages.

In the NSCAS assessment, AEMO considered these committed transmission and generation projects in its analysis of system security and reliability needs in Victoria over the NSCAS horizon.

System security and reliability assessment outcomes

At this time, AEMO has not identified an NSCAS gap in Victoria over the five-year period. The assessment to date indicates that secure voltages can be maintained under forecast periods of low demand, but only marginally and very close to limits. Under studied minimum demand, for certain generator dispatch patterns[49], post-contingent voltages are forecast to come close to allowable limits. AEMO will continue to review this emerging risk.

In the NSCAS assessment, the ability to keep post-contingent voltages below maximum allowable levels during low demand periods with few synchronous generating units online relied on an extensive set of assumptions, including the following:

- Switching one 500 kV Hazelwood to South Morang line out of service.
- New 220 kV 100 MVAr reactors commissioned according to schedule (1 x 100 MVAr reactor by January 2021, and additional 3 x 100 MVAr reactors by end of 2022).
- New committed generation contributing to reactive power support.
- Close to the full reactive absorption capability of online 500 kV connected generators, used pre-contingency.
- Careful tapping of 500/330 kV, 500/220 kV, and 330/220 kV transformers, to manage the voltage profile.

[48] NEM Generation Information July 2020, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[49] Aligned with one or more of the minimum acceptable combinations of synchronous machines for Victoria.

The highly specific transformer tapping patterns required to maintain a secure voltage profile under studied minimum demand conditions may be challenging to implement in a real-time operational environment.

This degree of tuning of the system could be very challenging in real-life operations. In 2021, AEMO will review further the operational implications. If this review does not provide confidence that the proposed solutions are manageable, AEMO may revise its assessment, including potentially declaring NSCAS gaps.

Emerging Victorian issues being monitored

AEMO conducted sensitivity studies to determine the impact on system security of any potential closure of the Alcoa Portland (APD) smelter. While no closure has been forecast or announced, this is a major load on the Victorian system that is important to system design and operations. For example, these studies showed that closure of APD would exacerbate current low load high voltage problems to the point where additional investment would be required to maintain system security.

The Victorian Government has announced a new 300 MW battery will be built near Moorabool that will participate in a system integrity protection scheme (SIPS) to increase transfer capacity on the Victoria to New South Wales interconnector (VNI)[50]. The battery is planned to begin operating by 1 November 2021. It is expected that this battery will provide reactive power support that will assist in managing high voltages during low demand periods. This battery has not been modelled in this NSCAS assessment, as it is not yet classified as committed on the AEMO Generation Information page[51]. AEMO will monitor the progress of this project and incorporate it into future analysis.

[50] Victoria Government Department of Energy Land, Water and Planning. The Victoriana Big Battery Q&A, at https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery/the-victorian-big-battery-q-and-a.

[51] AEMO. NEM Generation Information Page November 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2020/nem-generation-information-november-2020.xlsx?la=en. Commitment criteria are under the Background Information tab.

4. NSCAS assessment for market benefit ancillary services (MBAS)

4.1 Historical binding constraints assessment

Table 2 to Table 6 provide a list of historical system normal binding constraints which had binding impact[52] in excess of $50,000 for at least one hour in 2019, as identified in the 2019 NEM constraint report summary[53]. AEMO reviewed these constraints and engaged with TNSPs to consider potential actions to deliver market benefits. As outlined below, a wide range of activities are currently underway, recently completed, or proposed during the NSCAS assessment period to improve the capability of the network. Given those activities, AEMO has not identified any NSCAS gaps for maximising market benefits.

4.1.1 New South Wales historically binding constraints assessment

Table 2 Assessment of historically significant binding constraint equations in New South Wales

Network limitation	Binding impact (2019)	Proposed action
N>N-NIL_CLDP_1 **Avoid overload of the Coleambally to Darlington Point 132 kV line (99T) under system normal.**	$5,628,170	The 99T line capacity upgrade project to re-conductor line 99T to increase its normal summer day rating to 190 MVA and summer day contingency rating to 225 MVA has been completed. This project has mitigated the thermal constraints in the area allowing additional transfer capacity of up to 60 MW.
N^^V_NIL_1 **Avoid a voltage collapse in Southern New South Wales for the loss of the largest Victorian generating unit or Basslink.**	$2,543,881	TransGrid plans to install a 330 kV 100 MVAr shunt capacitor bank at Wagga substation in May 2022 which is expected to increase southward transfer by 30 MW. Additionally, AEMO has established a new NMAS agreement 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.
N_BROKENHSF_FLT_26 **Limit Broken Hill Solar Farm upper limit to 26 MW to manage post-contingent voltage oscillations.**	$1,429,240	This constraint was lifted in April 2020 following the successful testing of new tuned inverter settings of five solar farms in the West Murray area.
N>N-NIL_DC **Avoid an overload on the Armidale to Tamworth line 85 or line 86 on the trip of the other Armidale to Tamworth line 85 or line 86.**	$58,668	The constraint is along the Queensland to New South Wales interconnector (QNI) flow path. It will be considered in future assessments of QNI transfer capability.

[52] The binding impact of a constraint is derived by summarising the marginal value for each dispatch interval (DI) from the marginal constraint cost (MCC) re-run over the period considered. The marginal value is a mathematical term for the binding impact arising from relaxing the right hand side (RHS) of a binding constraint by one MW. As the market clears each DI, the binding impact is measured in $/MW/DI. The binding impact in $/MW/DI is a relative comparison but is not otherwise a meaningful measure.

[53] AEMO. NEM Constraint Report Summary Data 2019, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2019/nem-constraint-report-2019-summary-data.xlsx.

4.1.2 Queensland historically binding constraints assessment

Table 3 Assessment of historically significant binding constraint equations in Queensland

Network limitation	Binding impact (2019)	Proposed action
Q.NIL_COLVSF1 **Limit Collinsville Solar Farm to thermal rating of Powerlink's ring main unit (RMU).**	$905,855	Options are being investigated by the distribution network service provider (DNSP) to relieve this constraint. A solution is expected to be implemented in 2021.
Q_NIL_STRGTH_MEWF **Limit Mt Emerald Wind Farm output depending on the number of units online at Stanwell, Callide B, Callide C, Gladstone, Townsville GT, Kareeya and Barron Gorge generators. Limit output to zero if minimum online generation requirements not met.**	$405,396	This is a system strength constraint. Powerlink has an interim agreement with CleanCo to partially mitigate the system strength issues in North Queensland and is investigating permanent solutions.
Q^^NIL_QNI_SRAR **Limit flow from Queensland to New South Wales on QNI to avoid voltage instability on trip of Sapphire–Armidale (8E) 330 kV line.**	$338,816	The Armidale (330 kV) 120 MVAr capacitor and the committed projects to expand Queensland to New South Wales transmission transfer capacity (QNI Minor) will mitigate this constraint.
Q>NIL_SRMB_M020/1 **Susan River Solar Farm constrained to emergency rating of M020/1 Susan River to Maryborough 66 kV line. If Susan River Solar Farm runback scheme is armed, this constraint is 'swamped', or 'cancelled' out, and the right hand side only is dispatched.**	$176,401	Constraint does not bind when Susan River Solar Farm runback scheme is armed. Scheme is normally enabled.
Q:N_NIL_AR_2L_G & Q::N_NIL_AR_2L-G **Limit flow from Queensland to New South Wales on QNI to avoid transient instability for a 2L-G fault at Armidale.**	$172,627	The Armidale (330 kV) 120 MVAr capacitor and the committed project to expand Queensland to New South Wales transmission transfer capacity (QNI Minor) will mitigate this constraint.
Q>NIL_BI_CAGS_CALV_O **H8 Boyne Island feeder bushing (FB) limit on Calliope River to Boyne Island 132 kV lines, 7104/7105 (T022 Callide A to T152 Gladstone South) 132 kV lines closed with 132 kV split between T022 Callide A and H015 Lilyvale.**	$117,980	Powerlink has previously assessed this constraint and found no economically viable options to mitigate.
Q>NIL_BI_xxx **H8 Boyne Island feeder bushing (FB) limit on Calliope River to Boyne Island 132 kV lines, 7104 and 7105 (T022 Callide A to T152 Gladstone South) 132 kV lines open with 132 kV intact/split between T022 Callide A and H015 Lilyvale.**	$87,292	Powerlink has previously assessed this constraint and found no economically viable options to mitigate.
Q:NIL_CS **Central Queensland to Southern Queensland (CQ-SQ) transient stability (Upper Limit of 2,100 MW).**	$75,571	Powerlink plans to investigate various options to increase CQ-SQ transfer capacity as per section 7.4.2 of the 2020 Powerlink TAPR[A].
Q:NIL_OAKEY2SF **Limit Oakey 2 Solar Farm to 0 MW when Oakey GT is online to prevent transient instability for a 3-phase fault at Tangkam.**	$70,202	Constraint subsequently removed.

A. At https://www.powerlink.com.au/sites/default/files/2020-10/Transmission%20Annual%20Planning%20Report%202020%20-%20Full%20report.pdf.

4.1.3 South Australia historical binding constraints assessment

Table 4 Assessment of historically significant binding constraint equations in South Australia

Network limitation	Binding impact (2019)	Proposed action
S_WIND_1200_AUTO & S_NIL_STRENGTH_1 **Upper limit (1,300 to 1,750 MW) for South Australian non-synchronous generation for minimum synchronous generators online for system strength requirements. Automatically 'swamps' out ('cancelled' out) when required HIGH combination is online.**	$8,084,357	S_NIL_STRENGTH_1 replaced the constraint S_WIND_1200_AUTO. The planned installation of synchronous condensers at Davenport and Robertstown in 2021 will alleviate this constraint by raising the level at which it is expected to bind.
S>V_NIL_SETX_SETX1 **Avoid overloading of South East 132/275 kV transformer on the trip of the remaining South East 132/275 kV transformer, when the transformer component of the South East Control Scheme (SECS) is out of service.**	$1,332,092	SECS is normally in place to alleviate this constraint.
S>V_NIL_NIL_RBNW **Avoid overloading Robertstown – North West Bend No. 1 or No. 2 132 kV lines for no contingencies.**	$894,162	The Robertstown to North West Bend No. 2 132 kV line was uprated from 80°C to 100°C ratings in May 2019. This was justified through market benefits. Upgrades to Murraylink controls necessary to implement the increased ratings operationally occurred in October 2020. Therefore, this constraint is expected to bind less in 2021.
S>NIL_NIL_NWMH2 **Avoid an overload of North West Bend – Monash 132 kV line No. 2 under system normal conditions.**	$450,786	The North West Bend to Monash No. 2 132 kV line was uprated from 80°C to 100°C ratings in May 2019. This was justified through market benefits. Upgrades to Murraylink controls necessary to implement the increased ratings operationally occurred in October 2020. Therefore, this constraint is expected to bind less in 2021.
S>NIL_TINO3_TINO4 **Avoid an overload of the Torrens Island Power Station – New Osborne 66 kV Line No. 3. Assume circuit breaker 5536 at New Osborne is closed. This constraint 'swamps' out ('cancelled' out) if New Osborne circuit breaker 5536 is OPEN.**	$282,427	Constraint did not bind in 2018 or the first half of 2020. Therefore, it is unlikely this constraint will be a persistent problem warranting investment.
V^^S_NIL_MAXG_xxx **Maintain Long Term Voltage Stability limit from Victoria to South Australia for the loss of the largest generation block in South Australia with South East Capacitor available.**	$179,783	The constraint binding hours declined from 2018 to 2019 despite increase in binding impact from 2018 to 2019. Therefore, it is unlikely to be a persistent problem warranting investment.
S>NIL_HUWT_STBG2 **Limit Snowtown wind farm generation output to avoid Snowtown–Bungama line overloading upon loss of Hummocks–Waterloo 132 kV line.**	$178,507	ElectraNet is monitoring this constraint to determine if economically efficient options to mitigate are likely.

Network limitation	Binding impact (2019)	Proposed action
S>NIL_BWMP_HUWT **Avoid an overload of the Hummocks–Waterloo 132 kV on trip of Blyth West – Munno Para 275 kV line.**	$140,837	The constraint had low binding hours and binding impact in 2018. Therefore, it is unlikely to be a persistent problem warranting investment.
S>NIL_NIL_SETX12 **Avoid an overload of either South East 132/275 kV Transformer 1 or Transformer 2 under system normal.**	$125,723	South East transformers have previously had short term emergency loading limits applied to mitigate this constraint. ElectraNet has previously investigated the possibility of installing a third transformer to mitigate the constraint and found it would not yield net market benefits.
S^NIL_PL_MAX **Sets maximum generation limit at Port Lincoln due to voltage stability limit.**	$120,722	The committed Eyre Peninsula upgrade will alleviate this constraint. The upgrade consists of a new double-circuit line between Cultana and Yadnarie initially energised at 132 kV (but with the option in future to energise at 275 kV) and a new 132 kV double circuit line from Yadnarie to Port Lincoln. Implementation is planned by December 2022.
S_WATERLWF_RB **Limit Waterloo Wind Farm output to its runback active power capability.**	$100,126	ElectraNet is monitoring this constraint to determine if economically efficient solutions to mitigate are likely.
S>NIL_SGBN_SGSE-T2 **Avoid an overload of Snuggery Mayura – South East T 132 kV line on trip of Snuggery-Blanche 132 kV line.**	$99,915	A control scheme to alleviate this constraint is in service under system normal conditions.
SVML_ROC_80 **Rate of Change (South Australia to Victoria) constraint (80 MW / 5 Min) for Murraylink.**	$92,916	Constraint based on limit advice provided by Murraylink operator.
S>NIL_LKDV_CNRB **Avoid an overload of Canowie–Robertstown 275 kV line on trip of Mt Lock–Davenport 275 kV line.**	$76,608	Davenport–Robertstown 275 kV Removal of Plant Limits project was completed in October 2019. This project included removal of limits on the Canowie–Robertstown 275 kV line. The AEMO 2020 half yearly constraints summary report records a binding impact of only $5,648 for this constraint.

4.1.4 Tasmania historically binding constraints assessment

Table 5 Assessment of historically significant binding constraint equations in Tasmania

Network limitation	Binding impact (2019)	Proposed action
T>T_NIL_110_1 **Avoid a pre-contingency overload of the Derby to Scottsdale Tee 110 kV line.**	$3,244,767	This constraint equation constrains a single generator, which is subject to other limitations which could bind if this constraint was relieved. TasNetworks will monitor this constraint. If the generator mitigates other limitations, this constraint could bind more frequently. This constraint uses the transmission line workbook ratings, an option to relieve the constraint is to incorporate dynamic line ratings, which requires the installation of a weather station in the Derby area.
T_MRWF_QLIM_xx **Limit Musselroe Wind Farm to 150 MW if less than 96% of dynamic volt-amperes reactive (DVAr) capacity online.**	$433,109	DVAr assets are part of Musselroe Wind Farm. Wind farm output reduces with reduced DVAr capacity.
T>T_NIL_BL_110_18_1 **Avoid an overload on the Lake Echo Tee to Waddamana No.1 line (flow to North) for loss of Tungatinah to Waddamana No. 2 110 kV line.**	$233,115.2	This constraint binds due to a low circuit rating. AEMO has consulted with TasNetworks and determined that there is currently no economic solution to address this limit. In the long term, lines may be uprated as part of long term strategy for the Upper Derwent 110 kV network.

4.1.5 Victoria historically binding constraints assessment

Table 6 Assessment of historically significant binding constraint equations in Victoria

Network limitation	Binding impact (2019)	Proposed action
V_BANSF_BBD_60 **Limit Bannerton Solar Farm upper limit to 60 MW if Boundary Bend loading is less than 10 MW.**	$1,023,513	This is a distribution system constraint. AEMO will consult with the DNSP (Powercor) to determine if options have been identified to mitigate this constraint,
V_GANWRSF_FLT_25 **Gannawarra solar fam upper limit to 25 MW to manage post-contingent voltage oscillation.**	$899,365	This constraint has been lifted in April 2020 following the successful testing of new tuned inverter settings of 5 solar farms in the West Murray area.
V_GANWR_SF_BAT_50 **Limit total output of Gannawarra Solar Farm and Battery (generation component) to 50 MW to prevent an overload of the Gannawarra transformer.**	$894,670	The purpose of the constraint is to manage loading of market participant's own transformer.

Network limitation	Binding impact (2019)	Proposed action
V>>V_NIL_3 **Avoid the overload of Dederang to South Morang 330 kV line (flow South) for the trip of the parallel line.**	$788,397	Constraint will be partially mitigated by the committed VNI upgrade (late 2022) which includes 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. Constraint will also be mitigated by Victorian SIPS project from November 2021.
V_OAKHILL_TFB_42 **Oaklands Hill Windfarm upper limit of 42.7 MW due to Oaklands Hill windfarm Total Fire Ban mode operation, dispatch (DS) only.**	$758,019	This is a distribution system constraint to manage risks on Total Fire Ban days.
V_T_NIL_FCSPS **Basslink limit from Victoria to Tasmania for load enabled for frequency control special protection scheme (FCSPS).**	$592,891	Limit advice from TasNetworks. Constraint is to maintain frequency in Tasmania within acceptable levels for trip of Basslink.
V_KARADSF_FLT_45 **Limit Karadoc Solar Farm upper limit to 45 MW to manage post-contingent voltage oscillation.**	$290,378	This constraint has been lifted in April 2020 following the successful testing of new tuned inverter settings of five solar farms in the West Murray area.
V_WEMENSF_FLT_44 **Limit Wemen Solar Farm upper limit to 44 MW to manage post-contingent voltage oscillation.**	$254,538	This constraint has been lifted in April 2020 following the successful testing of new tuned inverter settings of five solar farms in the West Murray area.
V_CWWF_GFT_5 **Crowlands Wind Farm associated fast tripping scheme (disabled), Limit Crowlands Wind farm upper limit to 5 MW, DS only.**	$245,465	A control scheme to alleviate this constraint is in service under system normal conditions.
V^^SML_NSWRB_2 **Victoria to South Australia transfer limit on Murraylink to avoid voltage collapse at Red Cliffs for the loss of either the Darlington Point to Balranald (X5) or Balranald to Buronga (X3) 220 kV.**	$240,622	This constraint can be mitigated by activation of the NSW Murraylink runback scheme. Activation will be progressed in 2021.
V>V_NIL_7 **To prevent the overload of either Mount Beauty–Dederang 220 kV line (flow north) for trip of the Eildon–Thomastown 220 kV line.**	$219,019	Identified as a monitored limitation in the 2020 Victorian Annual Planning Report (VAPR)[A]. Possible network solutions recorded in 2020 VAPR.
V_BANNERTSF_FLT_44 **Limits Bannerton Solar Farm upper limit to 44 MW to manage post-contingent voltage oscillation.**	$154,576	This constraint has been lifted in April 2020 following the successful testing of new tuned inverter settings of five solar farms in the West Murray area.

Network limitation	Binding impact (2019)	Proposed action
V_MWWF_GFT_5 **Murra Warra Wind Farm associated fast tripping scheme (disabled), Limit Murra Warra Windfarm upper limit to 5 MW, DS only. 'Swamp' out ('cancel' out) if the scheme is in service (enabled).**	$137,008	A control scheme to alleviate this constraint is in service under system normal conditions.
V>>V_NIL_1B **To avoid overloading Murray to Dederang No. 2 330 kV line (flow Murray to Dederang) for loss of the parallel No. 1 line, DBUSS-Line control scheme enabled, 15 min line ratings, feedback.**	$130,500	Identified as a monitored limitation in the 2020 VAPR. Possible network solutions recorded in 2020 VAPR. Constraint will also be mitigated by Victorian SIPS project from November 2021.
V^^N_NIL_1 **To avoid a voltage collapse around Murray for loss of all APD potlines.**	$96,627	Identified as a monitored limitation in the 2020 VAPR. Possible network solutions recorded in 2020 VAPR. Also, the 2020 TransGrid TAPR notes plans for a 330 kV 100 MVAr capacitor at Wagga which is anticipated to improve transfer by 75 MW.
V>>V_NIL_1A **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.**	$81,414	Identified as a monitored limitation in the 2020 VAPR. Possible network solutions recorded in 2020 VAPR. Constraint will also be mitigated by Victorian SIPS project from November 2021.
V>>V_NIL_5 **To prevent overload of either Mount Beauty to Dederang 220 kV line (flow North) for trip of the parallel line.**	$80,401	Identified as a monitored limitation in the 2020 VAPR. Possible network solutions recorded in 2020 VAPR.

A. At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2020/2020-vapr.pdf?la=en.

4.2 Forward-looking constraints assessment

Through the consultation process, AEMO has updated the NSCAS description and quantity procedure to include the ability to assess future binding constraints. The procedure was updated to include this capability in October 2020 in parallel with the 2020 annual NSCAS review.

AEMO will include the assessment of relevant future binding constraints together with input from market participants in the 2021 annual NSCAS review. For more information please refer to Section 5.

5. Next steps

Continuing review and re-assessment of needs

In this assessment, AEMO has signalled the need for a continuous planning approach to manage the power system as it evolves, requiring much more agile, adaptive, and transformative approaches to planning even in the short term. It is important to continue with a range of existing measures to ensure the system can be operated securely and reliably, including:

- Maintaining existing operational practices, including dispatch of reactive plant, line switching and/or re-configuration, use of NMAS contracts, and in extreme cases, direction by AEMO of specific equipment.
- Reviewing limit equations to ensure constraint equations continue to capture the full range of system conditions as generation dispatch patterns change.
- Progressing some planned investments in new reactive plant and generation and transmission projects.

Although AEMO has not identified any NSCAS gaps at this stage, AEMO expects that the power system will operate close to its limits in some areas and under some conditions and rely more heavily on operational measures to remain secure. AEMO will monitor the situation closely, in particular in Queensland and Victoria, and if conditions change then AEMO may declare gaps as required before the next scheduled annual review.

AEMO will also continue to monitor and assess the issues identified in this report, including through joint planning processes with TNSPs. These include the impact of co-incident minimum demand across regions, and the delivery of voltage management and reactive power support in the context of changing synchronous generation operation and lowering minimum demand.

The NSCAS assessment reveals areas where traditional network planning assumptions may not sufficiently account for the impact of changing generation, network and demand dynamics. AEMO will continue to assess and adapt key planning assumptions including assumptions about line-switching for voltage management, dynamic reactive reserve requirements, feasibility of practices identified in this assessment in real-time operations, operational risk profiles, potential for alternative technology solutions, and alignment between the NSCAS and system strength frameworks.

Engagement with stakeholders

AEMO encourages stakeholders to provide input on this assessment. In particular, views are welcomed on:

- Emerging trends noted for the system and market and the implications for future system management.
- Concerns identified on a range of issues, including feasibility of implementing planning assumptions while appropriately managing levels of risk in operations, and whether the identified potential future drivers for change may occur much earlier than anticipated – for example, rate of development of VRE, rate of decline in minimum demands, and changes to operation of existing synchronous generation.
- The opportunities signalled for meeting likely future needs for NSCAS and other system services with newer technology, including asynchronous generation, and the requirements to do so.
- Constraints AEMO could consider under the historical or future binding constraints analysis that may provide market benefits under the MBAS assessment, along with proposed solutions, costs, and justification that positive net market benefits are likely to result from the proposed solution[54].
- Any other relevant inputs with regards to the market benefits assessment.

Comments and feedback should be submitted to planning@aemo.com.au **by 26 February 2021**.

[54] AEMO's 2020 update to the NSCAS description and quantity procedure included the ability for market participants and other stakeholders to provide input to the MBAS assessment.

A1. Detailed NSCAS review assumptions

This section captures the assumptions used in the 2020 NSCAS review. Participants may contact AEMO via Planning@aemo.com.au should they require further information on the assumptions used in this review.

A1.1 Current and forecast minimum and maximum demand

The published 2020 ESOO[55] minimum and maximum demand forecast for each region was used for the 2020 NSCAS review. Forecast maximum and minimum demand outcomes vary significantly year-on-year, because they are heavily dependent on weather, time of day or week, and behavioural variations in response to these drivers.

Both maximum and minimum demand are measured at the regional level; this is because the peaks and lowest demands occur at different times in different regions and cannot be added together.

Minimum demand modelled

Minimum demand is a key concern with respect to managing system security, in particular high voltages. It can change the behaviour of synchronous generation resulting in lower fault levels, less dynamic reactive support and higher system voltages.

Typically, minimum operational demand occurs either overnight, due to low underlying consumer demand, or in the middle of the day, when underlying consumer demand is offset by distributed PV generation. Focusing on the latter, it is evident that any change to the forecast uptake of distributed PV will have a material impact on minimum demand forecasts.

In the 2020 ESOO, the forecast distributed PV uptake was updated. Distributed PV uptake was previously forecast in 2019 in development of the 2020 Integrated System Plan (ISP). For the 2020 ESOO forecast, AEMO obtained distributed PV uptake forecasts from both the Commonwealth Scientific and Industrial Research Organisation (CSIRO)[56] and Green Energy Markets (GEM)[57] for a range of modelling scenarios. Consistent for both, cumulative NEM-wide distributed PV uptake forecasts were generally revised upwards across the scenarios. This finding was mainly driven by strengthened consumer confidence in distributed PV uptake, as evidenced by the recent trend of strong sales and installations (continuing through the COVID-19 pandemic), above the levels forecast in 2019.

The NSCAS minimum demand analysis assumed the 90% POE for both the Central scenario and the Central Downside with High DER minimum demands for each state. Connection point data was used, reconciled to the regional minimum demand.

AEMO has improved the RSAS minimum demand NSCAS assessment by using connection point forecast data for the first time. AEMO notes this is a development area, and work is ongoing to improve these forecasts.

To capture the effects of COVID-19 in this NSCAS review, AEMO has included the Central scenario with economic downturn and high DER to explore possible impacts on minimum demand should COVID-19

---

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

[56] CSIRO, 2020 projections for small-scale embedded technologies, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/csiro-der-forecast-report.pdf?la=en.

[57] AEMO Green Energy Markets 2020 projections for distributed energy resources, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

impacts persist longer than expected. The Central Downside with high DER captures a more sustained economic downturn and lower manufacturing activity before returning to trend by 2023-24, and examines how higher distributed PV uptake, possibly stimulated by government recovery efforts, could affect grid consumption and therefore affect the management of voltages particularly under minimum demand.

Table 7 Central scenario and Central Downside High DER (DHD) sensitivity 90% POE minimum operational demand forecasts as sent-out

Year	New South Wales (Summer)		Queensland (Shoulder)		South Australia (Shoulder)		Tasmania (Summer)		Victoria (Shoulder)	
	Central	Central DHD	Central	Central DHD	Central	Central DHD	Central	Central DHD	Central	Central DHD
2020-21	4,967	4,744	3,963	3,601	348	263	824	819	2,586	2,340
2021-22	4,858	4,665	3,936	3,624	232	154	818	813	2,156	1,884
2022-23	4,764	4,552	3,838	3,550	172	91	811	805	1,753	1,473
2023-24	4,646	4,344	3,749	3,402	123	17	801	790	1,362	1,084
2024-25	4,493	4,069	3,653	3,183	73	-85	792	777	954	637

Maximum demand forecast

Across most NEM region forecasts, close to record high maximum operational demand periods are still being observed, despite annual operational consumption declining due to DER uptake. This is because operational maximum demand now typically occurs at time periods closer to sunset, when distributed PV provides little contribution.

The 10% POE maximum demand Central and Step Change scenarios were used in the voltage analysis of the NSCAS assessment, to identify any reactive needs to prevent low voltages across the NEM under system normal and post contingency.

All NEM regions except Tasmania have a summer maximum demand. Tasmania maximum demand is driven by heating load occurring in the winter.

Table 8 Central and Step Change scenario 10% POE maximum operational demand forecasts as sent-out

Year	New South Wales (Summer)		Queensland (Summer)		South Australia (Summer)		Tasmania (Winter)		Victoria (Summer)	
	Central	Step	Central	Step	Central	Step	Central	Step	Central	Step
2020-21	13,786	14,428	9,523	9,836	3,245	3,317	1,679	1,713	9,859	10,248
2021-22	14,205	14,716	9,867	10,027	3,255	3,261	1,774	1,826	9,738	10,056
2022-23	14,311	14,833	9,981	10,086	3,282	3,291	1,780	1,820	9,703	9,961
2023-24	14,433	14,850	10,104	10,168	3,320	3,303	1,786	1,808	9,658	9,906
2024-25	14,400	14,889	10,143	10,242	3,320	3,320	1,790	1,808	9,605	9,922

The 2020 ESOO provides an indicative reliability forecast of any potential reliability gaps where unserved energy (USE) is in excess of the reliability standard and Interim Reliability Measure (IRM) identified over a

10-year outlook period under a range of demand and supply scenarios. The NSCAS assessment leverages off the ESOO to identify any potential gaps that can be addressed through NSCAS. The 2020 ESOO has not identified any reliability gaps in excess of the reliability standard for the first five years.

A1.2 Generation five-year outlook

Committed generation projects

Committed and committed*[58] scheduled and semi scheduled generation projects from the NEM Generation Information July 2020[59] were used in the NSCAS review representing information, as shown in Table 9.

During the NSCAS review, in November 2020, the NEM Generation information page was updated; only generator projects that were considered likely to impact the outcome of the NSCAS assessment were included.

Table 9 Committed generation projects in the NEM included in the 2020 NSCAS Review

Region	Project	Generation capacity (MW)	Anticipated full commercial use date*
New South Wales	Bango 973 Wind Farm	155	April 2021
	Biala Wind Farm	111	April 2021
	Collector Wind Farm	225	Mar 2021
	Crudine Ridge Wind Farm	138	April 2021
	Darlington Point Solar Farm	275	December 2020
	Goonumbla Solar Farm	70	November 2020
	Limondale Solar Farm 1	220	March 2021
	Molong Solar Farm	36	December 2020
	Snowy 2.0	2,040	March 2025
	Sunraysia Solar Farm	229	February 2021
	Wellington Solar Farm	211	February 2021
Queensland	Gangarri Solar Farm	120	March 2021
	Kennedy Energy Park	58	July 2021
	Maryrorough Solar Farm	35	March 2021
	Middlemount Sun Farm	26	December 2020
	Warwick Solar Farm	64	March 2021
South Australia	Lincoln Gap Wind Farm stage 2	86	October 2021
	Temporary Generation South	123	In service

[58] Committed* represents projects that have met the requirements to be classified as "Advanced", and construction or installation has commenced.

[59] NEM Generation Information July 2020, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Commitment criteria are explained under the Background Information tab.

Region	Project	Generation capacity (MW)	Anticipated full commercial use date*
Victoria	Berrybank Wind Farm	181	January 2021
	Bulgana Green Power Hub Battery Energy Storage system	20	September 2021
	Bulgana Green Power Hub Wind Farm	204	September 2021
	Cohuna Solar Farm	31	April 2021
	Glenrowan West Sun Farm	132	March 2021
	Kiamal Solar Farm	200	February 2021
	Moorabool Wind Farm	312	July 2021
	Stockyard Hill Wind Farm	532	November 2021
	Winton Solar Farm	85	April 2021
	Yatpool Solar Farm	94	December 2020

Generation retirements

The NSCAS assessment included generator retirements[60] listed in Table 10.

Table 10 Generator retirements in the NEM accounted for in the 2020 NSCAS Review

Region	Power Station	Generation capacity (MW)	Retirement date
New South Wales	Liddell unit 4	500	April 2022
	Liddell unit 1	500	April 2023
	Liddell unit 2	500	April 2023
	Liddell unit 3	500	April 2023
Queensland	Mackay GT	34	April 2021
South Australia	Osborne	180	December 2023
	Torrens Island A unit 2	120	September 2020
	Torrens Island A unit 4	120	September 2020
	Torrens Island A unit 1	120	September 2021
	Torrens Island A unit 3	120	September 2022

A1.3 Transmission network five-year outlook

All committed projects were considered in service in the year according to the latest information provided by the TNSP in consultation and/or through the TAPR.

[60] Generating unit expected closure years are from AEMO's Generation Information, November 2020, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Table 11 summarises the committed projects modelled that impacted the NSCAS assessment; like-for-like replacements and minor network updates have not been included in the table below.

Table 11 Committed transmission projects in the NEM included in the 2020 NSCAS Review[61]

Region	Project	Expected project date
New South Wales	**Expanding QLD to NSW Transmission Transfer Capacity (QNI Upgrade);** Uprating of Liddell-Muswellbrook (#83), Muswellbrook-Tamworth (#88) and Liddell-Tamworth (#84) 330 kV lines. Install SVCs at Dumaresq and Tamworth substations or alternative dynamic reactive plants. Install shunt capacitor banks at Tamworth, Armidale and Dumaresq substations.	June 2022
	Armidale shunt capacitor 120 MVAR shunt capacitor bank at Armidale	March 2022
	Rookwood Rd transformer 2 re-located to Sydney East Sydney East transformer 3 decommissioned	In progress
	Stockdill 330 kV substation Establish a new 330 kV Stockdill substation and divert Upper Tumut–Canberra and Williamsdale–Canberra 330 kV lines into Stockdill. Install a new 330/138.6/11 kV 375 MVA transformer at Stockdill. Establish two new feeders, namely Canberra–Stockdill 132 kV and Stockdill–Woden 132 kV feeders. Decommission the two Canberra 300/138.6/16 kV 400 MVA transformers.	December 2020 (Stockdill substation energisation) June 2021 (Full project completion)
	Wagga Wagga Capacitor bank 1 x 100 MVAr 330 kV capacitor bank at Wagga Wagga	May 2022
	Powering Sydney's Future • 1 x 330 kV cable 46 between Beaconsfield and Rookwood substations • De-rate cable 41 and series reactor between Beaconsfield and Sydney South from 330 kV to 132 kV (the 150 MVAr shunt line reactor on cable 41 is kept as a busbar reactor on the 330 kV busbar at Sydney South Substation)	Late 2022
Queensland	**Gin Gin Substation Rebuild** • Decommission Gin Gin capacitor bank • Bypass feeder 819/826 • Establish tee between T1/814/816 • Establish tee between 813/815 and T2	June 2022
	Mudgeeraba Transformer 3 Decommissioning Removal of 275/110 kV transformer at end of technical life	June 2022
	Belmont Transformer 2T Decommissioning Removal of 275/110 kV transformer at end of technical life	November 2020

[61] This NSCAS review has incorporated additional project information that was not relevant to assessments for AEMO's 2020 Electricity Statement of Opportunities (ESOO), since the focus of this NSCAS review is different to that of the ESOO.

Region	Project	Expected project date
	Loganlea 110/33 kV Transformer Decommissioning Removal of 110/33 kV transformer at end of technical life	June 2023
	Belmont Transformer 3T Decommissioning Removal of 275/110 kV transformer at end of technical life	April 2021
	Lilyvale Transformer 3 and 4 Replacement Replace existing 2 x 132/66 kV 80 MVA transformers with 2 x 160 MVA	June 2023
	Strathmore Second Transformer Establish additional 275/132 kV transformer at Strathmore	December 2022
South Australia	**NCIPAP Smart Wires Power Guardian Technology Trial** Install Smart Wires power guardian units on the Templers – Waterloo 132 kV line and uprate: • Robertstown–Para 275 kV line • Templers–Roseworthy 132 kV line	November 2020 (smart wires) April 2021 (line uprating)
	Main Grid System Strength Support • To address system strength and inertia gaps in South Australia install four synchronous condensers, two at Davenport and 2 at Robertstown.	January 2021 (Davenport) April 2021 (Robertstown)
	Eyre Peninsula Link Construct a new: • Double circuit line 275 kV from Cultana to Yadnarie initially energised at 132 kV. Double circuit 132 kV line from Yadnarie to Port Lincoln.	December 2022
Tasmania	**Sheffield substation connection point** A new connection point at Sheffield substation with a single 250 MVA supply transformer.	June 2021
	Burnie–Port Latta–Smithton 110 kV transmission corridor Reconfigure Port Latta Substation supply arrangement from loop in-and-out to double tee, realising market benefit of 20 MW capacity increase to accommodate new generation in the corridor	December 2021
Victoria[A]	**Transmission augmentation to access renewable energy in western Victoria** Stage 1: The installation of wind monitoring equipment and the upgrade of station limiting transmission plant on the: • Red Cliffs–Wemen 220 kV line • Wemen–Kerang 220 kV line • Kerang–Bendigo 220 kV line • Moorabool–Terang 220 kV line • Ballarat–Terang 220 kV line Stage 2: • A new 500 kV substation North of Ballarat	August 2021 (Stage 1) November 2024 (Stage 2)

Region	Project	Expected project date
	• A new 500 kV double-circuit transmission line from Sydenham to the new substation north of Ballarat • A new 220 kV double-circuit transmission line from substation north of Ballarat to Bulgana (via Waubra) • 2 x 500/220 kV transformers at the new substation north of Ballarat • Cut-in the existing Ballarat–Bendigo 220 kV line at a new substation north of Ballarat • Moving the Waubra Terminal Station connection from the existing Ballarat–Ararat 220 kV line to a new 220 kV line connecting the substation north of Ballarat to Bulgana • Cut-in the existing Moorabool–Ballarat No. 2 220 kV line at Elaine Terminal Station	
	Reactive Power Support Stage 1: • 100 MVAr reactor at Keilor 220 kV (NCIPAP Project) Stage 2 (RIT-T Project): • 100 MVAr reactor at Keilor 220 kV • Two 100 MVAr reactors at Moorabool 220 kV	January 2021 (Stage 1) October 2022 (Stage 2)
	Minor Victoria to New South Wales Upgrade (Victoria side only) • Second 500/330 kV transformer at South Morang • Uprate South Morang-Dederang 330 kV lines and series capacitors	December 2022
	Line parameter update Update Red cliffs to Kiamal to Murra Warra 220 kV line and Murra Warra 220 kV substation to Murra Warra Wind Farm line data based on EMS	2021
	West Melbourne (WMTS) Redevelopment: Staged replacement of four 150 MVA 220/66 kV transformers by three 225 MVA 220/66 kV transformer	2022
	Red Cliffs 1A 2A replacement Two Red Cliffs 21.5 MVA transformers will be replaced by one 150 MVA transformer.	2024

A. The Red Cliffs system strength remediation project is not captured here. The assumption is that the services procured, in the near term, under this remediation project are for system strength only and are not expected to provide any additional voltage support.

A2. Supplementary Queensland minimum demand information

AEMO observes that there are emerging risks that minimum demand in Queensland could be lower than the 2020 ESOO forecast. Early evidence includes observed higher uptake of distributed PV throughout 2020 than these forecasts. AEMO has commenced studies into requirements for Queensland under a range of sensitivities, to better inform and "bookend" the understanding of potential needs and challenges in relation to possible future minimum demand trends.

0 shows the Queensland minimum demand forecasts under three sensitivities that have been developed for use in ongoing studies into potential implications of future declines in minimum demand:

- A Central Downside High DER sensitivity with a 90% POE (as reported in the 2020 ESOO). This represents a 1-in-10-year minimum demand projection, as used for the 2020 NSCAS assessment.
- A Central Downside High DER sensitivity with a 95% POE. This represents a 1-in-20-year minimum demand projection.
- An alternative to the existing Central Downside High DER sensitivity with a 95% POE minimum demand projection and with changes to the assumptions about distributed PV growth. These changed assumptions for rooftop distributed PV installations (<100 kW) expand on changes observed to October 2020, with growth in distributed PV being projected to continue to accelerate at a rate similar to the rate of acceleration observed over the past three years[62].

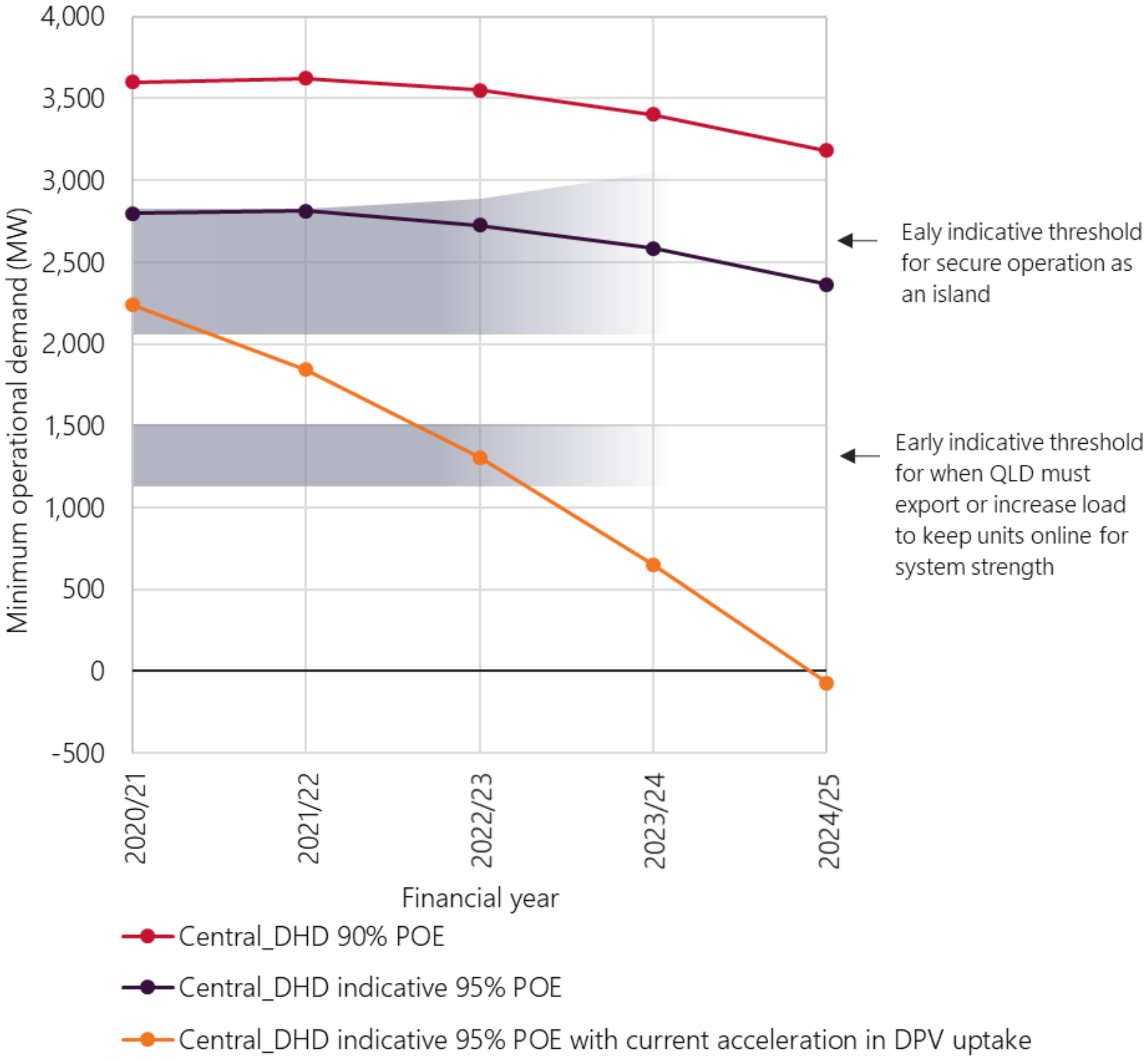
These alternative sensitivities have been very recently developed to further assist investigations into management of the power system in possible extreme minimum demand conditions. The outcomes have not been applied in this 2020 NSCAS assessment as the studies are ongoing at this time.

0 also shows early outcomes from studies that suggest indicative thresholds under certain conditions. These early indicative thresholds are intended to investigate where there may not be sufficient demand for secure operation of Queensland as an island, and an indicative level of demand where it may be necessary to export over interconnectors from Queensland to maintain sufficient units online for system strength. AEMO stresses that these results are early outcomes and further work is ongoing in this area.

These early outcomes are presented to highlight areas of further analysis required to further investigate emerging challenges raised by declining minimum demand. AEMO is continuing investigations in this area and in conjunction will explore NSCAS implications as studies progress.

[62] Rooftop distributed PV installations (<100 kW) growth rates have accelerated over each of the past three years. The lowest acceleration rate observed over the past three years was applied to each future year to 2024-25.

Figure 12 Queensland minimum operational demand (sent-out) for Central Downside high DER 90%POE, with indicative 95% POE sensitivities and early indicative thresholds for operation as an island



Glossary, measures, and abbreviations

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Glossary

Term	Definition
binding impact	Binding impact is used to distinguish between the severities of different binding constraint equations. It represents the financial pain associated with that binding constraint equation and can be a good way of picking up congestion issues. It is a relative term, not an absolute term.
committed generation projects	Generation that is considered to be proceeding under AEMO's commitment criteria (see Generation Information on AEMO's website).
committed transmission project	Transmission projects that have completed their regulatory approval processes.
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Distributed PV installed capacity is the total amount of cumulative distributed PV capacity installed at any given time.
maximum demand	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
minimum demand	Lowest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.

Units of measure

Abbreviation	Expanded name
DVAr	Dynamic volt-amperes reactive
kV	Kilovolts
MVA	Megavolt-amperes
MVAr	Megavolt-amperes reactive
MW	Megawatts

Abbreviations

Abbreviation	Expanded name
AEMC	Australian Energy Market Commission
AEMO	Australia Energy Market Operator
AER	Australian Energy Regulator
APD	Alcoa Portland (smelter)
CQ-SQ	Central Queensland to Southern Queensland
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed Energy Resources
DHD	Downside High Distributed Energy Resources
DS	Dispatch
DVAr	Dynamic volt-ampere reactive (type of Statcom)
ESOO	Electricity Statement of Opportunities
GEM	Green Energy Markets
IRM	Interim Reliability Measure
ISP	Integrated System Plan
LIL	Large industrial loads
MBAS	Market Benefits Ancillary Services
MVAr	Mega volt-ampere reactive
NEM	National Electricity Market
NER	National Electricity Rules
NSCAS	Network Support and Control Ancillary Services
NSW	New South Wales
POE	Probability of exceedance
PV	Photovoltaic
QLD	Queensland
QNI	Queensland to New South Wales interconnector
RIT-T	Regulatory investment test for transmission
RMU	Ring main unit
RSAS	Reliability and Security Ancillary Services
SA	South Australia
SECS	South East Control Scheme
SIPS	System Integrity Protection Scheme

Abbreviation	Expanded name
SVC	Static Var Compensator
TAPR	Transmission Annual Planning Report
TNSP	Transmission network service provider
USE	Unserved energy
VAPR	Victorian Annual Planning Report
VDS	Var Dispatch Scheduler
VNI	Victoria to New South Wales Interconnector