RELIABILITY
PANEL AEMC

REVIEW

Reliability Panel AEMC

FINAL REPORT

ANNUAL MARKET PERFORMANCE REVIEW 2018

04 APRIL 2019

INQUIRIES

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ABOUT THE RELIABILITY PANEL

The Panel is a specialist body established by the Australian Energy Market Commission (AEMC) in accordance with section 38 of the National Electricity Law and the National Electricity Rules. The Panel comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on reliability, security and safety on the national electricity system, and advising the AEMC in respect of such matters.

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FOREWORD

I am pleased to present this report setting out the findings of the Reliability Panel's annual review of market performance, for the period 2017/18.

The Panel has reviewed the performance of the national electricity market (NEM) in terms of reliability, security and safety over the 2017/18 period, in accordance with the requirements of the National Electricity Rules (Rules) and the terms of reference issued by the Australian Energy Market Commission (AEMC). Security concerns the technical resilience of the power system itself and is primarily the responsibility of the Australian Energy Market Operator (AEMO); reliability is about having sufficient capacity to meet consumer demand for energy and is primarily driven by efficient market investment. We have considered both historic trends and projections of the security and reliability of the NEM.

A number of key trends continued to play out during the period 2017/18. In particular, the generation mix continued to change, with significant new entry of variable, asynchronous generation. On the consumer side of the meter, there has been a continued uptake of distributed energy resources, with continued strong growth of rooftop PV. When coupled with the likely exit of older, thermal generation over the coming years, these trends will continue to create new challenges and opportunities for the secure and reliable operation of the NEM power system.

The 2017/18 period saw an increasing number of market interventions to maintain reliability and security. Interventions to maintain security included the significant number of directions issued by AEMO in South Australia to maintain system strength (an important security parameter). In Victoria, there were a number of instances where AEMO had to manually switch off high voltage transmission lines, to maintain voltages at stable levels. In the reliability space, the Reliability and Emergency Reserve Trader (RERT) mechanism was activated for the first time in the history of the NEM.

These market interventions are a purposeful part of the existing design of the NEM. They provide an emergency backstop to maintain the security and stability of the system. However, they should not be long-term solutions, as they come at a significant cost to consumers, and can have unintended consequences.

Market interventions come at a significant cost to consumers; as an example, the system strength interventions in South Australia during the reporting period cost approximately $34 million per annum.[1] The Panel considers that while intervening in the market is a necessary and important tool for AEMO, in the longer term it is preferable for the market to provide the services required to maintain security and reliability. Where these system needs are clearly identified and incentivised, the market would be expected to provide them at a lower cost than through intervention measures.

1 The cost of $34 million does not represent the total cost of directing generators in South Australia to ensure adequate system strength. It is also appropriate to take into account trading amounts that would otherwise be paid to those generators and wider impacts on wholesale market prices. This is discussed in more detail in Chapter 7 of the consultation paper for the AEMC's *Investigation into intervention mechanisms and system strength in the NEM*. Source: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

The Panel notes that the market bodies have already undertaken, and continue to progress, an extensive program of reform to address these challenges. It takes time for these reforms to come into effect, however once they are in place, they should help to reduce the extent of the interventions needed. This AMPR provides an overview of this extensive work program; the Panel intends to monitor and review how the work program has progressed in its next AMPR.

Over the 2017/18 period, the reliability of electricity supply continued to be maintained with no unserved energy over the period. However, this was in part due to the activation of the RERT on two occasions to maintain the power system in a reliable operating state. Prior to 2017/18, the RERT had only been procured three times and had never been activated. Consumers bore a cost of $51.99 million in 2017/18 for the activation of the RERT.[2]

Maintenance of power system security continues to be a key challenge for the NEM. System performance as measured against relevant system security standards has continued to be problematic. In the period 2017/18, the Panel notes that the frequency performance of the system has continued to degrade. In addition, new challenges are emerging in relation to system strength and maintaining stable voltages on parts of the power system.

Frequency control: Good frequency control should meet the requirements of the frequency operating standard (FOS). To the extent that power system frequency deviates from the requirements of the FOS, this may reduce the resilience of the power system to non-credible contingency events. The likelihood that the system will recover from a contingency event increases when frequency is within the normal frequency operating band set out in the FOS.

Some elements of the FOS normal operation requirements were not met in both the mainland and in Tasmania during 2017/18.[3]

On the mainland the frequency of the power system remained within the normal operating frequency band more than 99 per cent of the time, for each month of the reporting period (as per the requirements of the FOS). However, there were 50 events where system frequency took longer than allowed in the FOS to be returned to the normal operating frequency band following a disturbance.

In Tasmania, frequency performance did not meet either of these FOS requirements for normal operation,[4] with system frequency not being maintained in the normal band for more

2 AEMO, *RERT 2017-18 cost update*, 2018, p. 1. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/RERT-Update—-cost-of-RERT-2017-18.pdf

3 The frequency operating standard sets out a number of requirements for operation of the power system, including several different measures of frequency performance during normal operation. Only some of these normal operation requirements were met in 2017/18. The elements of the FOS relevant to normal operation of the power system include: 1) the range of allowable frequencies in bands corresponding to the operating state of the power system. The current requirement is that for 99 per cent of the time, the power system is maintained within the range of 49.85 – 50.15Hz (the normal operating frequency band), over any 30 day period, and 2) times for the stabilisation and recovery of the power system frequency following a frequency deviation. The current requirement is that during normal operation, if the power system frequency deviates outside the normal band, it must be returned to the normal band within five minutes. There are two separate FOS determined by the Reliability Panel, one for the mainland and another for Tasmania, reflecting the different physical characteristics of these two parts of the NEM.

4 The current frequency operating standard for the NEM mainland and Tasmania define different frequency boundaries that apply for different types of contingency events. This is due to the specific tolerances of Tasmanian generators to frequency variations and the intention at the time the standard was set to limit the cost of FCAS procurement.

than 99 per cent of the time for 11 months in 2017/18. Further, there were 295 events where frequency took longer than allowed in the FOS to be returned to the normal band.

The Panel also notes advice from AEMO regarding the system separation event that occurred on 25 August 2018.[5] AEMO's incident reporting for this event highlighted a decline in frequency control capability and system resilience.[6] While the causes of this incident are complex and continue to be investigated, they demonstrate the increasing complexity and ongoing importance of maintaining system security for a transitioning power system.

System strength: Levels of system strength are declining in north Queensland, south-west New South Wales, north-western Victoria and South Australia. System strength is a property of the power system that resists changes in voltages in response to a change in loading conditions. To maintain sufficient levels of system strength in South Australia, AEMO used a number of market interventions, including constraining off asynchronous generation like wind and solar generators, and issuing directions to operate synchronous generators, like gas generators.

In 2017/18, the number and length of security directions increased significantly. Most of the directions that occurred in 2017/18 were to ensure adequate system strength for the secure operation of the South Australian power system.

These system strength interventions come at a significant cost to consumers. The amount of compensation paid out to generators is currently estimated to be approximately $34 million per annum.[7] The issuance of directions also has flow on effects to overall price outcomes in the NEM.[8] The estimated impact on wholesale market prices as a result of issuing directions for system strength as at September 2018 exceeded $270 million.[9]

5 The Panel notes that this incident was outside the reporting period for this annual market performance review. The Panel decided to include some high level analysis of this event in this report to illustrate the extent of potential supply impacts for consumers following major security events in the power system. This event will be discussed in more detail in the *2019 Annual market performance review*.

6 AEMO, *Queensland and South Australia system separation on 25 August 2018*, final report, January 2019, p. 3.

7 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 20. The cost of $34 million does not represent the total cost of directing generators in South Australia to ensure adequate system strength. It is also appropriate to take into account trading amounts that would otherwise be paid to those generators and wider impacts on wholesale market prices. This is discussed in more detail in Chapter 7 of the consultation paper for the AEMC's *Investigation into intervention mechanisms and system strength in the NEM*. Source: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

8 Where a direction has been issued, AEMO will apply intervention pricing in accordance with its Intervention Pricing Methodology. Intervention pricing is triggered when AEMO intervenes in the market by activating the RERT or issuing a direction. Intervention pricing determines the price at which the market clears during an AEMO intervention event, while compensation is a separate process and is paid only to certain parties – those who are directed to provide services and those who are affected (i.e. dispatched differently) due to the direction.

9 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 21. While the basis of this $270 million figure is not set out in the ElectraNet report, the Panel surmises that it reflects the difference between spot prices as set by the "intervention pricing run" and prices produced by the "dispatch run" when system strength directions are in effect, averaged over the period from April 2017 to September 2018. If this is the case, it is likely that this figure represents an upper limit of the impact of intervention pricing on wholesale energy prices. This is because the market could be expected to self-correct at least to some degree if intervention pricing was not applied and prices were allowed to fall in response to additional generation coming online in response to a system strength direction. For example, in South Australia, removing intervention pricing and allowing the spot price to fall to reflect the supply demand balance that follows from the direction could be expected to prompt generators to rebid or withdraw from the market rather than pay to generate when prices fall to strongly negative levels. Secondly, higher spot prices typically do not translate immediately or directly into higher prices for consumers. This is because most retailers have hedge contracts with generators in order to manage wholesale price volatility. However, contract prices are negotiated having regard for expectations about future spot prices. As such, higher spot prices can be expected to put upward pressure on contract prices and thus wholesale energy costs. For more information, see: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

Voltage control: Another security issue that arose during the reporting period is voltage control in South Australia and Victoria. In those states a need was identified for additional reactive support to maintain transmission system voltages within operational limits during minimum demand periods. While AEMO is progressing a regulatory investment test for transmission to address this issue in Victoria, it is currently managing over voltages with short term manual de-energisation of high voltage transmission lines, combined with directions to generators. In effect, this involves the switching off of large high voltage transmission lines to lower the system voltage, but has the consequence of reducing the available pathways for energy to flow from generation to consumers.[10] The extent of this manual switching has increased since the reporting period - in November 2018, AEMO had to de-energise three separate 500kV lines in Victoria for the first time in the history of the NEM.

These manual line switching interventions can come at a cost to consumers, by impacting on the ability of the transmission system to effectively transport energy within and between regions. It may also result in transmission network reliability risks, as the system becomes more vulnerable to unexpected shocks if more lines are switched off and are unavailable to be used.

In the context of these challenges, the Panel acknowledges the significant body of work completed and underway that is currently considering how to maintain the ongoing security and reliability of the NEM.

In terms of work already completed, the Panel notes that many of the reforms already completed by the market bodies will take some time to be fully implemented. For example, while the *Managing power system levels* rule came into effect on 1 July 2018, ElectraNet will not finalise installation of synchronous condensers to provide necessary system strength until 2020. The Panel considers that it is important to allow sufficient time for these framework changes to take effect.

The Panel also acknowledges the extensive work program currently underway, which will consider whether additional changes are required, in addition to the significant reforms already progressed and being implemented. This work program includes:

- The AEMC's *Frequency control interim arrangements* project, which will focus on short term changes to manage frequency deterioration in the NEM, including encouraging generators to provide frequency control responses where feasible.
- The AEMC's *Frequency control work plan*, which will focus on designing new, coordinated and lowest-cost ways to deliver frequency control services over the medium to longer term.
- The AEMC's investigation into *Intervention mechanisms and system strength* in the NEM, which will consider the effectiveness of the intervention framework in light of the increasing use of directions by AEMO to manage system security, and how related system strength frameworks could be improved to avoid the need for directions.

10 AEMO, *Victorian reactive power support, regulatory investment test for transmission project specification consultation report*, May 2018.

- The Panel's *Review of the frequency operating standard*, which assesses whether the existing standard is appropriate to maintain a secure power system as the generation mix changes.
- AEMO's *Victorian reactive power support* regulatory investment test, which assesses and ranks different electricity transmission investment options that address the need for additional reactive support in Victoria.
- The Energy Security Board's (ESB) *Retailer reliability obligation*, which aims to incentivise retailers, and other large users, to invest in dispatchable electricity generation in the NEM regions, when it is expected there will be a gap between generation and forecast peak demand.
- The AEMC's *Enhancement to the reliability and emergency reserve trader* rule change, which has proposed a number of broad changes to the NEM's emergency reserve to improve its effectiveness.
- The AEMC's *Wholesale demand response mechanism* rule changes, which are considering the introduction of mechanisms to enable more wholesale demand response in the NEM.
- *AEMC/AEMO/Australian Energy Regulator (AER) virtual power plant (VPP) trial*, which will inform changes to regulatory frameworks and operational processes so VPPs can play a bigger role in the energy market.
- The AEMC's *Short term forward market* rule change, which will consider providing an AEMO-operated platform to enable market participants to contract for electricity in the week leading up to dispatch, to help enable more demand response.

Furthermore, given the trends indicated, the Panel considers it is imperative that work continues looking at identifying what the system needs to stay secure and reliable, and how the market can be incentivised to meet those needs.

In addition to these ongoing projects, the Panel acknowledges the various work programs being progressed by the market bodies that will consider what else needs to be done to maintain system security in a changing power system environment. AEMO's forward work program will involve technical consideration of the various system needs, specifically what services will be required in what timeframes, as well as developing strategies for the management of these issues. The AEMC will also be progressing relevant work, including consideration of how security services may be procured in a coordinated manner by multiple parties as part of an improved access regime for the connection of generators to the power system, through the *Coordination of generation and transmission investment - access and charging review*. The AEMC will also consider the concept of system resilience, through the work it has underway, now that the AEMO and AER investigations into 28 September 2016 South Australian Black System event are largely complete.

The Panel intends to monitor and review how these work programs progress over the coming year with a view to recommending in the *2019 Annual market performance review* whether any further work remains to be done or if there are key issues that need to be addressed.

The Panel has structured this report to enhance usefulness for different readers. A short summary report is provided for those readers seeking a high level overview of the review and key trends. The main report provides further detail through additional commentary on the review and these key trends. Technical detail is then available in the relevant appendices.

The preparation of this report could not have been completed without the assistance of AEMO, the AER, network service providers, and state and territory government departments and regulatory agencies in providing relevant data and information. I acknowledge their efforts and thank them for their assistance.

Finally, the Panel commends the staff of the AEMC secretariat for their efforts in coordinating the collection and collation of information presented in this report, and for drafting the report for the Panel's consideration.

Dr Brian Spalding, Chairman, AEMC Reliability Panel,

Commissioner, AEMC

CONCISE REPORT

1 This report sets out the findings of the Reliability Panel's (Panel) 2018 Annual Market Performance Review (AMPR) as required by the National Electricity Rules (rules or NER). This review is conducted in accordance with terms of reference issued by the Australian Energy Market Commission (AEMC). Covering the period 1 July 2017 to 30 June 2018, the 2018 AMPR includes observations and commentary on the security, reliability and safety performance of the power system primarily relating to that timeframe, but also comments on current and emerging trends.

2 This concise report is structured as follows:

- Key findings of this report.
- Key concepts: security, reliability and safety are the three main areas for performance considered by the Panel when undertaking the AMPR.
- Market trends: the key trends in generation, interconnection and demand, these being central to the areas of performance of the market the Panel reviews.
- Reliability review: an overview of reliability outcomes and forecasts in the NEM.
- Security review: an overview of security outcomes and emerging trends in the NEM.
- Safety commentary: a short summary of safety in the NEM.
- Relevant policy developments: a short summary of other policy work currently underway that is relevant to the ongoing security and reliability of the NEM.

3 This concise report is intended to provide a high level summary of key trends in the NEM. More detailed information and commentary is provided in the main body of the report and in the relevant appendices.

Key findings of this report

4 For the period 2017/18, the Panel has identified a number of continuing and emerging trends, each of which is relevant to the ongoing security and reliability of the NEM.

5 The NEM generation fleet continues to evolve, with entry of large volumes of variable, renewable generation and the expected exit of dispatchable, thermal generation. In addition, a growing number of customers are installing residential rooftop PV and battery storage behind the meter. The scale of these changes is significant, representing a wholesale shift in the structure and function of the NEM power system.

6 This fundamental change in the NEM is having a number of impacts, including a growing requirement for market interventions. For example, interventions were required to maintain security, such as the switching out of transmission lines to manage over voltages in Victoria, as well as the curtailment and direction of multiple generators to maintain system strength in South Australia. Further to this, the Panel notes that the frequency performance of the NEM continued its longer term deterioration over the period 2017/18. While the reliability standard was met during the reporting period, AEMO intervened in the market on two separate occasions and activate the reliability emergency reserve trader.

7 These market interventions are a purposeful part of the existing design of the NEM. They provide an emergency backstop to maintain the security and stability of the system. However, they should not be long term solutions, as they come at a significant cost to consumers, and can have unintended consequences.

8 The Panel considers that while intervening in the market is a necessary and important tool for AEMO, in the longer term it is preferable for the market to provide the services required to maintain security and reliability. Where these system needs are clearly identified and incentivised, the market would be expected to provide them at a lower cost than through intervention measures.

9 In light of these challenges, the Panel notes the considerable body of work completed and underway to strengthen and enhance the NEM, so that it can adapt to these fundamental changes.

10 In terms of work already completed, the Panel notes that many of the reforms already completed by the market bodies will take some time to be fully implemented. For example, while the *Managing power system levels* rule came into effect on 1 July 2018, ElectraNet will not finalise installation of synchronous condensers to provide necessary system strength until 2020. The Panel considers that it is important to allow sufficient time for these framework changes to take effect.

11 The Panel also notes the ongoing work being progressed by the AEMC and AEMO to better manage frequency. The AEMC is also progressing its investigation into intervention mechanisms and system strength in the NEM, which will consider the effectiveness of the intervention framework and how related system strength frameworks could be improved to avoid the need for directions.

12 The AEMC and AEMO are developing future work programs considering what new services may be needed to facilitate the ongoing transformation of the power system. Considerations of system resilience and new system services will be progressed through various projects including the AEMC's *Coordination of generation and transmission investment - access and charging review* and the AEMC's *Review of the 28 September 2016 South Australian Black System event.* AEMO's forward work program will involve technical consideration of the various system needs, specifically what services will be required in what timeframes, as well as developing strategies for the management of these issues - both of which are key inputs into adapting or creating new frameworks.

13 Over the coming year, the Panel will continue to monitor these, and other relevant work programs, with a view to identifying any gaps in issues or trends not being actively addressed, as this relates to the ongoing performance of the NEM power system.

Key concepts

14 The focus of the review is the security, reliability and safety performance of the NEM. It is therefore important to explain the meaning of these concepts.

15 ***Security:*** Security relates to the maintenance of the power system within specific technical operational limits, including specific frequency and voltage limits. System security is managed directly by AEMO and network operators in accordance with applicable technical standards. Maintaining the security of the power system is one of AEMO's key functions. The practices adopted by AEMO to manage power system security are defined in its operating procedures and guidelines, which have been developed from overarching guidelines and standards developed by the Panel and obligations under the rules. AEMO operationally manages security through a variety of measures such as constraints applied in the dispatch of generation or intervening in the market by directing participants or instructing load shedding. AEMO is required to keep the system in a secure operating state. The power system is defined to be in a secure operating state if:

- the power system is in a satisfactory operating state[11]
- the power system will return to a satisfactory operating state following the occurrence of any credible contingency event[12] in accordance with the power system security standards.[13]

16 Clause 4.2.6(b)(1) of the rules requires AEMO to take all reasonable actions to adjust, wherever possible, the system's operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within 30 minutes.

17 ***Reliability:*** At a wholesale level, reliability is about having sufficient generation, demand side response, and interconnector capacity in the system to generate and transport electricity to meet consumer demand. References to reliability in this review do not include the concept of transmission and distribution network reliability.[14]

18 In relation to the Panel's review, reliability is considered in terms of unserved energy. Unserved energy refers to an amount of energy that is required (or demanded) by consumers but which is not supplied due to a shortage of generation or interconnection capacity.

19 The reliability performance of the NEM is currently measured against the reliability standard. The current reliability standard is focussed on the supply available from the wholesale market and is expressed in terms of the maximum expected unserved energy, or the maximum amount of electricity expected to be at risk of not being supplied to consumers, per financial year.

20 The current reliability standard is that no more than 0.002 per cent of demand in a region

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11 A satisfactory operating state is defined in clause 4.2.2 of the rules. It refers to operation of equipment within voltage and current limits as well as the frequency of the power system being within defined frequency bands.

12 A contingency event means an event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission elements (clause 4.2.3(a) of the NER). A credible contingency event means a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope (clause 4.2.3(b) of the NER). For example, a credible contingency could include the failure of a single generating unit or a single major item of transmission plant.

13 Power system security standards are defined in Chapter 10 of the NER as the standards (other than the reliability standard and the system restart standard) governing power system security and reliability, and to be approved by the Panel on the advice of AEMO, but which may include but are not limited to standards for the frequency of the power system in operation and contingency capacity reserves (including guidelines for assessing requirements).

14 The reliability provided by intra-regional transmission and distributions networks is regulated by jurisdictional governments. Outages on intra-regional transmission and distribution networks can affect the supply of electricity to consumers, but are considered separately to the supply of energy at the wholesale level, which forms the basis of the Panel's analysis here.

should be at risk of not being met. In simple terms, the reliability standard requires there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of forecast annual demand for electricity is expected to be supplied. The term 'expected' is important – it means a statistical expectation of a future state; an average across a wide range of future scenarios that could lead to unserved energy, weighted for probability, where the weights are the probabilities (or likelihood) that unserved energy will occur.

21 It is important to note that there are a number of other circumstances and events not related to generation reliability that may cause an interruption to consumer supply. These include:

- distribution network outages, which are by far the greatest cause of supply interruptions
- transmission network outages, in the non-bulk transmission sections of the transmission network (i.e., parts of the transmission network other than interconnectors)
- imbalances in generation and demand triggered by shortages in generation capacity due to a non-credible contingency.[15]

22 ***Safety:*** The safety of the national electricity system can be understood to mean that:

- the transmission and distribution systems and the generation and other facilities connected to them are safe from damage (safety in the technical safety sense); or
- the transmission and distribution systems and the generation, and other facilities connected to them are not a source of injury and danger (safety in the public safety sense).

23 It is open to the AEMC to request advice from the Panel on either or both technical safety of the national electricity system (power system security) or public safety issues relating to the national electricity system or specific aspects of those types of safety as it considers appropriate. The terms of reference issued by the AEMC clearly direct the Panel to focus on technical safety (power system security) rather than public safety in the 2018 AMPR.[16]

24 The Panel notes that while the general safety of the NEM, and associated equipment, power system personnel and the public is an important consideration under the National Electricity Law (NEL), in general terms, there is no national safety regulator for electricity. Instead, jurisdictions have specific provisions that explicitly refer to safety duties of transmission and distribution systems, as well as other aspects of electricity systems such as metering and batteries.[17]

Market Trends

25 There were a number of key market trends in the NEM in 2017/18, including the:

15 Non-credible contingencies may result in large disturbances to power system security, including large deviations in system frequency from the normal operating frequency of the NEM. These large deviations may trigger automatic protection systems known as under frequency load shedding schemes, which shed volumes of consumer load in a controlled manner in order to arrest the fall in frequency. As noted above, such interruptions are not classified as reliability issues and are not counted towards measurements of unserved energy.

16 Terms of reference are available at: https://www.aemc.gov.au/market-reviews-advice/annual-market-performance-review-2018

17 See section 2D(1)(a) of the NEL.

- entry of significant new generation capacity, mainly intermittent, large scale, asynchronous wind and solar generation[18]
- ageing of the existing thermal generation fleet
- highest period of growth for residential rooftop PV since installations were first recorded
- decline in minimum demand, largely due to the high residential rooftop PV uptake, and shift of maximum demand to later in the day due to declining ability of residential rooftop PV to offset demand
- notable change in interregional flows
- reduction of wholesale prices compared to the previous financial year.

The scale of many of these trends represent a fundamental shift in how the power system is structured and functions. As will be discussed in subsequent sections, these trends are having material impacts for both the reliability and the security of the NEM.

Supply side trends

26 A key trend on the supply side of the market is the expected exit of large synchronous thermal generation, coupled with significant new entry of large scale asynchronous, variable renewable generation.

27 The retirement of over 2,300 MW of synchronous generation within the next ten years has been announced. Further, a large amount of existing coal capacity will reach the end of its expected operating life over the coming two decades. The generators announced for withdrawal are:[19]

- AGL intends to retire Torrens A Power Station (480 MW) in South Australia, with two units withdrawing in 2019, and the other two in 2020 and 2021. The station will be partially replaced by the Barker Inlet Reciprocating Engine Power Station (210 MW), which will start operation in 2019.
- AGL has announced its intention to withdraw the Liddell Power Station (1,800 MW summer capacity) in New South Wales in 2022.
- Stanwell has announced its intention to withdraw the Mackay Power Station (34 MW) in Queensland in 2021.

28 The Panel notes that in November 2018, the AEMC made a rule that requires large electricity generators to provide at least three years' notice to the market before closing. The rule requires AEMO to maintain an up-to-date list of expected closure dates for generating units on its website. In March 2019, AEMO published for the first time the expected closure years for scheduled and semi-scheduled generators in the NEM. As of March 2019, there were 20 generators on the list with the closure years starting from 2028 to 2049. According to AEMO,

18 In Chapter 10 of the NER, asynchronous generating unit is defined as a generating unit that is not a synchronous generating unit. A synchronous generating unit, in turn, is the alternating current generators of most thermal and hydro (water) driven power turbines which operate at the equivalent speed of the frequency of the power system in its satisfactory operating state. Asynchronous units include wind and solar PV units which are connected to the power system via electrical inverters and are not synchronised to the grid.

19 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 49.

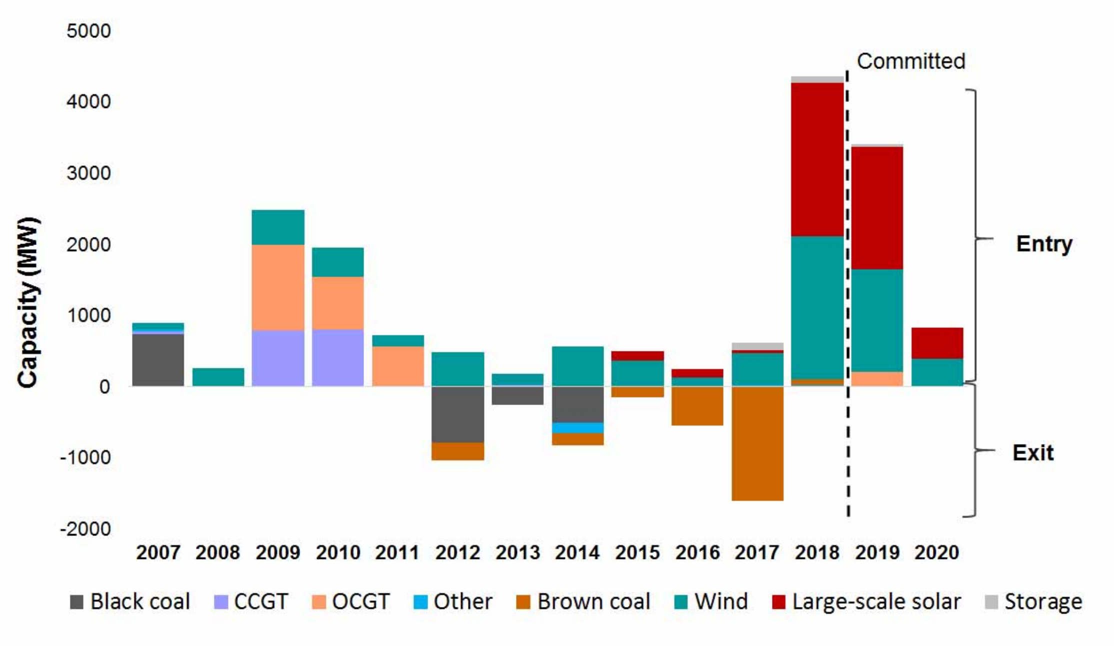
this data is expected to be updated fortnightly.[20]

29 Despite increased penetration of intermittent renewable generation and withdrawal of thermal coal-fired power generation, coal-fired thermal generation accounts for around half the installed capacity in the NEM.

30 Figure 1 shows the entry and exit of synchronous and asynchronous generating capacity in the NEM power system. The figure demonstrates that:

- over the past seven years significant retirement of thermal coal generation occurred
- there was a significant entry of wind and solar generation over the past years, particularly over 2018. Projections also show material new entry into 2019.[21]

Figure 1: Entry and exit of generation capacity in the NEM, 2007 to 2020



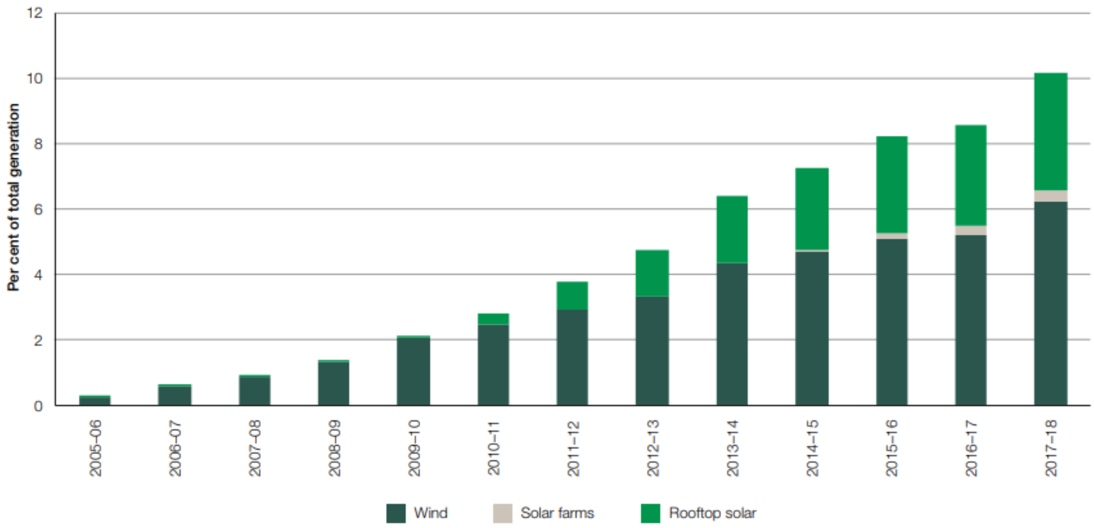
Source: AEMC analysis of data provided on AEMO's *Generator information page.*

31 In 2017/18, wind and solar (both residential rooftop PV and large scale) generation share of total output in the NEM reached ten per cent. The chart below demonstrates how the share of wind and solar in the overall generation mix has been rising rapidly in recent years.

20 For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

21 The Panel notes that the number of connection enquiries with network service providers also presents a significant volume of renewable generation seeking to connect to the system. As at 21 January 2019, there were 51,568 MW of proposed generation. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

Figure 2: Wind and solar generation share of total output in the NEM



Source: AER, *Wholesale electricity market performance report*, December 2018.
Note: The figure includes only solar generation from larger, registered solar farms with capacity greater than or equal to 30 MW registered capacity.

32 Material trends can also be identified at the regional level. In particular, in 2017/18 more than 40 per cent of energy generated in South Australia was sourced from wind generation.

33 Changes in the generation mix may have impacts on the reliability of the NEM by influencing the supply-demand balance. While there has been significant investment in new generation capacity in recent years, much of this capacity is variable, semi-scheduled or non-scheduled generation.

34 Changing generation mix has a number of impacts on reliability of the electricity supply. Firstly, the intrinsic intermittency of variable renewable generation can make it considerably harder to forecast long term its output than other forms of generation, although advances in technology are making it easier to undertake this forecasting.

35 Currently most of this variable renewable generation is non-dispatchable (at least in the absence of adequate storage capacity). This means that AEMO cannot depend upon those types of generation to ramp up when, say, a shortage is emerging, because the availability of this generation is dependent on the weather.

36 The displacement of dispatchable generation with variable renewable generation has the potential to affect the liquidity of secondary markets for the provision of hedging contracts.[22] One of the reasons for this is that historically, variable renewable generation has often been financed by long term power purchase agreements (PPAs)[23], rather than on the basis of

22 A hedge contract typically takes the form of a derivative contract based around the wholesale spot price. They often take the form of swaps, caps and collars, and are designed to manage the exposure of all counterparties to price volatility in the spot market.

23 These PPAs typically take the form of an offtake agreement where an agreed amount is paid for each MWh produced. These

underwriting hedge products in the secondary contract market. To the extent that these generators are financed through PPAs, rather than on the basis of secondary market contracts, there may be a corresponding impact on the number of hedging contracts traded, and a corresponding reduction in liquidity in the secondary contracts market.[24] The availability of hedging contracts through a liquid secondary contract market plays an important role in providing certainty for market participants and informing their decisions in the face of risky market conditions. The contract market also supports investment and reliability decisions by providing market participants with signals of market expectations of future spot prices and incentivising generators to be available when they are needed most (generators often increase production during high price/tight demand-supply periods). Therefore, it is important to maintain the liquidity of the forward contracts market.

37 The confluence of the above factors could result in tightening of the supply-demand balance in the market over time, which could have implications for reliability.

38 These trends may also have implications for the security of the NEM. In particular, changes in the ratio of synchronous and asynchronous generation in the NEM may decrease the amount of physical inertia[25] available and can also reduce system strength[26], both of which can impact on key system security parameters. Reductions in availability of synchronous generation may also affect the ability of AEMO and network service providers to manage voltage and stability limits in the NEM, as synchronous generation traditionally provided this capability as an inherent aspect of operation.

39 The Panel notes that the market is adapting to the technology transformation that is currently occurring in the NEM, and that there are a number of examples of new technologies and approaches being integrated and trialled in the NEM to provide new ways to control system services, including frequency support from battery storage, wind farms, load aggregators and virtual power plants.

Demand side trends

40 Overall total consumption and demand is projected to rise in coming years, however, actual consumption of grid-supplied energy is projected to remain relatively flat over the next 10 years (see *2018 ESOO operational forecast* line in the chart below). A major factor influencing this outcome is the increased penetration of residential rooftop solar PV.[27]

arrangements do not give consideration to when the energy is produced and are purely volumetric in nature.

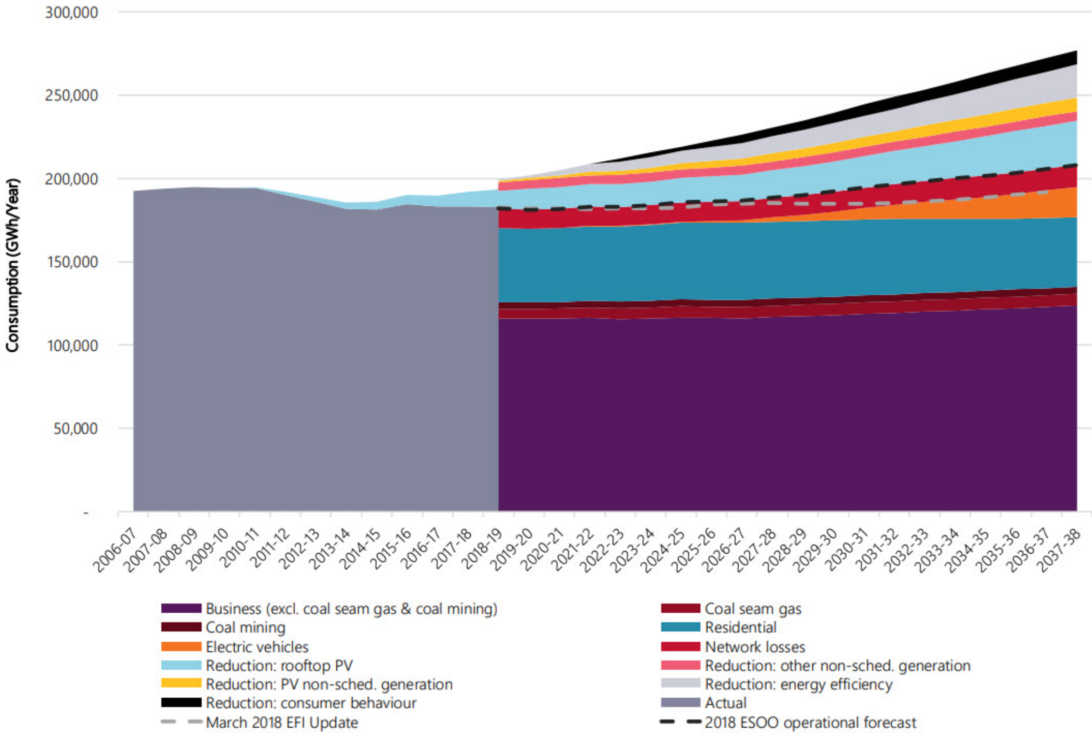
24 The Panel notes that this may change in the future, depending on the investment and operational preferences of new generators. The Panel also notes the emergence of new firming arrangements entered into by variable and dispatchable generators, such as the recent signing by Snowy Hydro of firming contracts for 888 MW of variable wind generation.

25 Conventional electricity generators, like hydro, coal and gas, operate with large spinning turbines that are synchronised to the frequency of the power system. The large rotating mass of the turbine and alternator of a synchronous generating unit has a physical inertia which must be overcome in order to increase or decrease the rate at which the generator is spinning. In this manner, large conventional generators that are synchronised to the system act to dampen changes in system frequency.

26 System strength is a property of the power system that resists changes in voltage in response to a change in loading conditions. It also relates to the level of current that can flow into a short circuit at a particular point in the power system. Low system strength means low fault current.

27 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 36.

Figure 3: Actual and forecast NEM electricity consumption, neutral scenario



Source: AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 37.

Note: Neutral scenario assumes a range of mid-point projections of economic growth, future demand growth, electric vehicle uptake and fuel costs, and existing market and policy settings. It also assumes moderate growth in DER aggregation, such that aggregated distributed batteries can be treated and operated as virtual power plants rather than operated to maximise the individual household's benefit.

41 The key trends in electricity demand and consumption include:[28]

- Total residential consumption is expected to rise from 2017/18 to 2022/23 due to:
  - an increase in new connections driven by population growth
  - number of appliances rise
  - gas to electric appliance switching.

42 However, this increase in total consumption is projected to be offset by a sustained residential rooftop PV uptake, battery storage installation and the use of more energy-efficient appliances.[29]

- There is an expectation of continued strong growth in residential rooftop PV solar generation, with 2017/18 being the highest period of growth in the sector. In 2017/18, about 1,300 MW of new capacity was installed, bringing the total residential rooftop PV capacity across the NEM to approximately 6,500 MW. In the short term, the high growth rate is forecast to continue. In the medium-term (5-10 years), slower growth is forecast,

28 Ibid, p. 38.

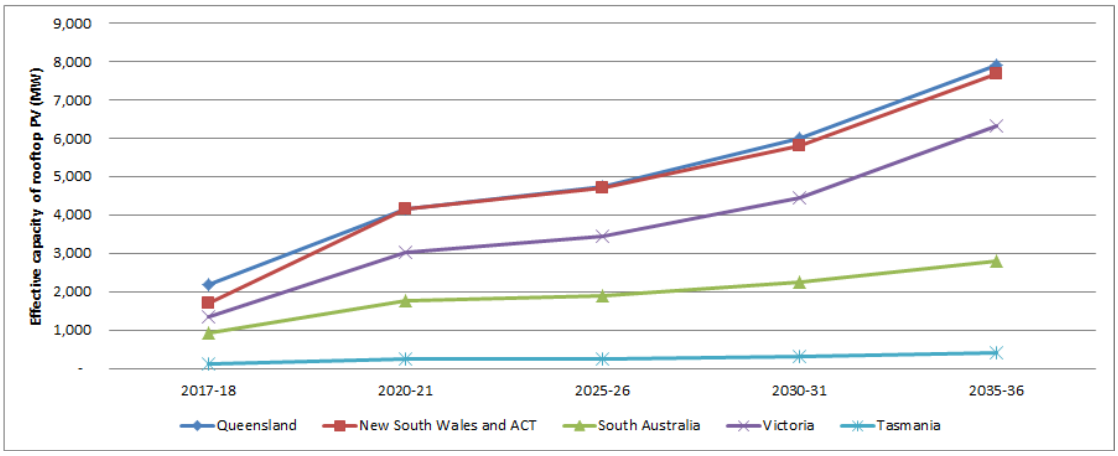
29 Ibid.

as retail prices are projected to lower and as the small-scale technology certificates incentive falls to zero by the year 2030.

- AEMO has forecast that by the end of the 20-year outlook period there will be 2.6 GW of behind-the-meter battery storage.
- Over the next five years maximum demand is projected to be relatively stable in most regions. Maximum operational demand is expected to peak later in the day due to growth in installed residential rooftop PV capacity.
- Overall minimum demand levels are forecast to fall rapidly over the next five years. Patterns of when minimum demand occurs during the day will also change, with all regions expected to experience minimum demand in the middle of the day within the next two years.[30]

43 The chart below shows AEMO's forecasts of projected uptake of residential rooftop PV. AEMO is forecasting strong growth in rooftop PV in all NEM regions, except Tasmania.[31] Queensland and New South Wales are forecast to experience the fastest rate of uptake. The total installed capacity of residential rooftop PV in 2035/36 across the NEM is projected to be over 25 GW. To put this in perspective, 25 GW is equivalent to around 45 per cent of the total installed generation capacity currently in the NEM.

Figure 4: Installed residential rooftop PV capacity forecasts



Source: AEMO.

44 AEMO forecasts that in 20 years, 15 per cent of all residential rooftop PV installations will be integrated with batteries, with behind-the-meter battery systems constituting 2.6 GW of storage capacity.[32]

45 High penetration of residential rooftop PV will continue to have a significant impact on

30 Excluding South Australia, which has been experiencing day minima since 2012.

31 The number of residential rooftop PV installations is forecast to grow in Tasmania, but at a much slower rate relative to the other regions.

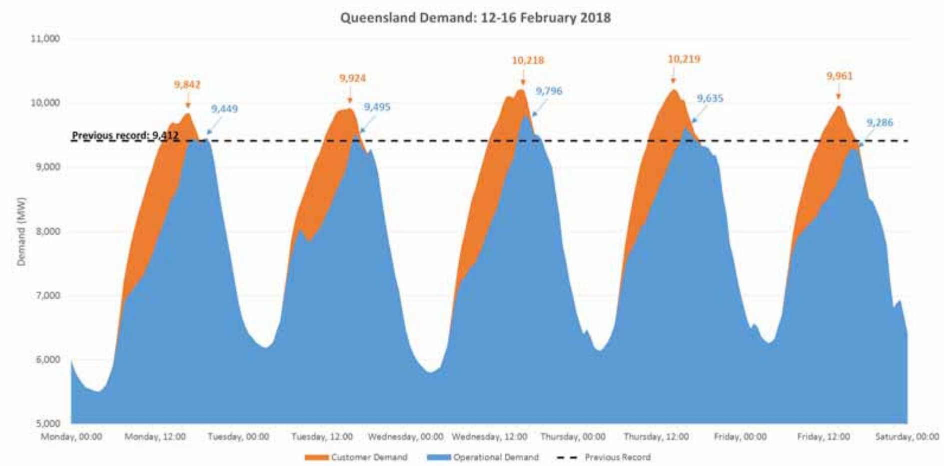
32 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 28.

minimum and maximum demands in the NEM. As such, it may both reduce the extent of peak demand as well as present some challenges for system security.

46 In terms of maximum demand, increased penetration of residential rooftop PV systems can reduce peak demand, which can help to reduce the cumulative stress on the power system that can occur on peak demand days.[33]

47 The residential rooftop PV impact on maximum demand was demonstrated between 12 and 16 February 2018, when Queensland experienced an intense heatwave. The chart below shows operational demand in Queensland. It also demonstrates how residential rooftop PV considerably reduced the extent of peak demand.

Figure 5: Queensland demand between 12 and 16 February 2018



Source: AEMO Energy Live, *Queensland's record-breaking demand explained,* 23 February 2018.

48 Further, consumers are now better-equipped than ever to manage their energy use. This may enable consumers to take actions to contribute to the overall reliability and security of the system. Although limited at this stage, this capability is likely to continue to improve in the future as technology advances. The emergence of distributed energy resources such as small-scale PV systems and the steadily declining cost of battery storage means that these technologies may already be an efficient source of back-up capacity in some circumstances.

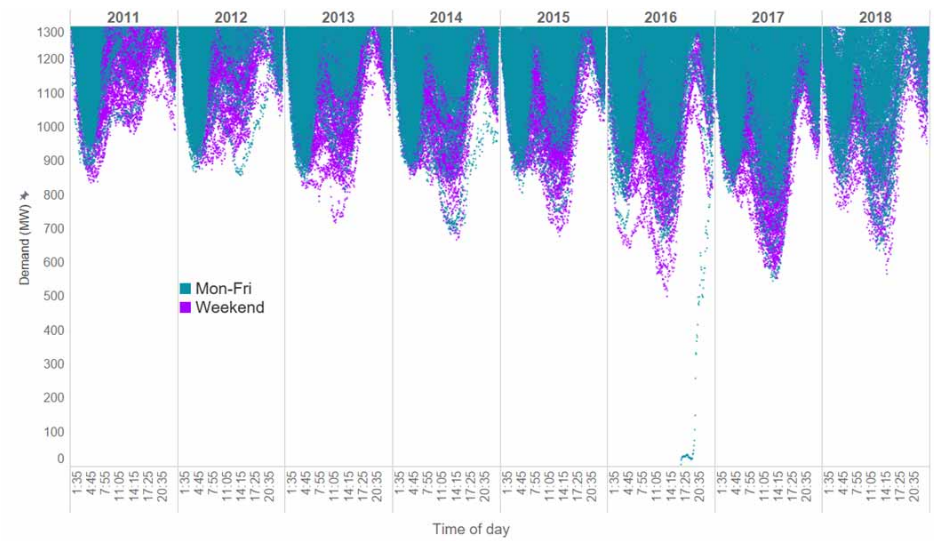
49 However, an increased penetration of variable renewable generation in the system can also result in an increased rate of change in the supply and demand balance within a day, which the rest of the system must respond to. It also markedly changes the required generation mix at different times of the day. As discussed in further detail below, this has particular implications for power system security.

50 In the context of minimum demand, the Panel notes:

33 This depends on the timing of peak demand and weather conditions. If peak demand occurs during the day when the sun is shining, energy produced by residential rooftop PV systems may diminish the stress on the power system by helping to reduce the extent of peak demand. If peak demand occurs at the evening, solar PV will not be able to assist with meeting this demand.

- Increasing residential rooftop PV uptake is expected to result in all regions experiencing minimum demand in the middle of the day within the next year or two.[34] This is exemplified in South Australia, which has already experienced a shift in the occurrence of minimum demand, as well as a general decrease in the absolute level of minimum demand. The chart below shows how levels of minimum demand in South Australia have been both decreasing in absolute terms, as well as shifting toward a pattern where minimum demand occurs around midday, since 2011.[35]
- In South Australia, the lowest level of minimum demand is expected to become negative by 2023/24.[36] This means that generation output in the region will exceed demand, mainly driven by output from residential rooftop PV generation in some hours. Figure 7 shows the projected changes in operational demand in South Australia from 2016/17 to 2036/37.

Figure 6: South Australia demand outcomes below 1300 MW



Source: AEMC analysis.

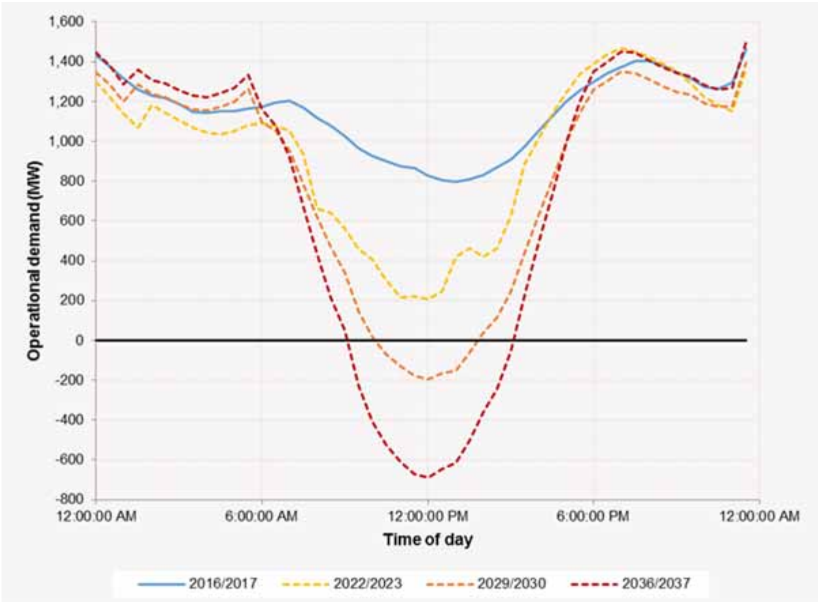
51 The chart below also demonstrates the way in which minimum demand shapes are forecast to change in the longer term in South Australia. This phenomenon of the 'hollowing out' of the demand curve during the middle of the day has been observed in many jurisdictions and is commonly associated with increased residential rooftop PV displacing demand.

34 Historically, minimum demand levels have tended to occur overnight.

35 Similarly, Tasmania experienced minimum demand at midday in 2017/18.

36 Notably, this is one year earlier than previously projected by AEMO. Sources: AEMO, *2018 Electricity forecasting insights*, March 2018; AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 47.

Figure 7: Projected changes in operational demand in South Australia



Source: AEMO.

52 The shift in timing and general reduction in levels of South Australian minimum demand may have a number of implications for operation of the system. AEMO has stated that: '[...] reduction in minimum operational demand [...] would result in more periods where there is little generation supplied by centrally managed generators to control the system. It may also reduce maintenance windows, as synchronous generation may be directed online to manage system strength'.[37]

53 AEMO consider that these effects of increased residential rooftop PV, and distributed energy resources (DER) more generally, can present a number of operational and system security challenges, including:

- system strength[38] risks
- voltage and frequency control issues
- the need for more sophisticated reserve management
- challenges for protection and control schemes operation, including emergency frequency control schemes.

54 A particular issue noted by AEMO relates to the effective function of under frequency load shedding schemes (UFLS) in the presence of high volumes of DER. UFLS serve as the last line of defence following a major power system disturbance, automatically disconnecting

37 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 46.

38 System strength is a property of the power system that resists changes in voltage in response to a change in loading conditions. It is also related to the level of current that can flow into a short circuit at a particular point in the power system, with low system strength conditions corresponding to low levels of available fault current. This availability of fault current affects the ability of system protection systems to operate correctly and the stability and dynamics of generator control systems.

distribution network feeder load blocks in a controlled manner to prevent a frequency collapse. However, high volumes of DER behind distribution network feeders can reduce the effectiveness of UFLS, by effectively reducing the amount of load that is shed when the feeder is tripped. In more extreme instances, where there is sufficient DER penetration behind a feeder so it is exporting power to the main system, the trip of the feeder could actually exacerbate an under frequency event.

55 AEMO has noted further security implications of high penetrations of DER, particularly distributed residential rooftop PV systems. This was examined by AEMO following the system separation event that occurred on 25 August 2018.[39] AEMO concluded that the distributed fleet of small scale, residential rooftop solar PV generally contributed to assist over-frequency management in Queensland and South Australia over the course of the event, by reducing output. However, in Victoria or New South Wales, solar PV provided no marked assistance.[40] Detailed analysis of the performance of a sample group of inverters showed:[41]

- approximately 15 per cent of sampled systems installed before October 2016 dropped out during the event
- of the sampled systems installed after October 2016, around 15 per cent in Queensland and 30 per cent in South Australia did not provide the over-frequency reduction capability required by the applicable Australian standard.

56 In response to this, AEMO recommended:[42]

- an immediate assessment of technical requirements of inverters
- work being undertaken with stakeholders to implement improved performance standards for inverters by end of 2019
- establishing solutions for obtaining data on the performance of distributed residential rooftop PV systems, and to develop the necessary simulation models to predict their response to system disturbances progressively up to the end of 2020.

57 In the context of minimum demand reduction and its shift to midday, having enough flexible capacity in the NEM available to 'ramp up' quickly is also a consideration that will need monitoring.[43] Achieving a balance of supply and demand may be more challenging in the future due to an increased penetration of variable renewable generation in the system and a more responsive demand side of the market, to the extent that this drives more significant ramping in the system.

58 However, the Panel notes that in November 2017, the AEMC made a final rule to change the settlement period for the electricity spot price from 30 minutes to five minutes, starting in July 2021. This will provide better price signals to match supply to demand. This will stimulate investment in fast response technologies, such as batteries, new generation gas peaker plants and demand response, which are particularly suited to providing this kind of

39 This event is discussed in more detail in chapter 5.

40 AEMO, *Queensland and South Australia system separation on 25 August 2018,* final report, January 2019, p. 6.

41 Ibid.

42 Ibid.

43 Ramping, and in particular ramping availability, is a reference to the availability of generation or scheduled load to be dispatched in response to changes in supply and demand in a timely manner.

fast ramping response.[44]

59 Another key trend that will be relevant to demand side outcomes will be the extent of uptake of electric vehicles. Depending on when they are charged and/or discharged into the power system, the batteries of electric vehicles have the potential to materially change demand patterns. However, based on the current level of uptake and in the absence of any policy incentives, AEMO forecasts that the uptake of electric vehicles will continue to be relatively small in the next decade. After 2027/28, electric vehicles are projected to become cost-competitive with petrol vehicles, due to the falling cost of electric vehicles and economies of scale. By 2037/38, 5.5 million residential and commercial electric vehicles NEM-wide are forecast in AEMO's neutral scenario.[45]

Interconnector capability and developments on interconnectors

60 Some notable changes occurred over 2017/18 in interregional flows:

- Victoria's exports decreased significantly in comparison with the last three years.
- Flows from Queensland into New South Wales (and then through to Victoria) increased as Queensland black coal generators increased output in 2017.
- Despite a consistent historic trend of South Australia importing energy over the last decade, in 2017/18 this trend reversed, and South Australia became a net exporter for the first time since 2008/09.

61 There have been a number of work programs progressed over the last year that are relevant to the development of interconnector capability in the NEM.

62 In July 2018, AEMO published the Integrated system plan (ISP). The ISP is a cost-based engineering optimisation plan by AEMO that forecasts the overall transmission system requirements for the NEM over the next 20 years.[46] It identifies a potential plan of the transmission investments that will be necessary to support the long term interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures. The ISP groups investments identified in the plan into three phases. These projects are discussed in more detail further in this report.

63 Various state governments have taken actions that are related to and complement the ISP. The New South Wales Government stated that it will provide a funding guarantee that will allow TransGrid[47] to bring forward preliminary planning work on ISP's group 2 projects.[48] Further, the South Australian government stated that direct assistance of $4 million will be provided in 2018/19 to enable transmission network operators to commence early works to support delivery of further interconnection between the eastern states and South Australia.

44 For more information, see: https://www.aemc.gov.au/rule-changes/five-minute-settlement

45 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 31. AEMO's neutral scenario assumes a range of mid-point projections of economic growth, future demand growth, electric vehicle uptake and fuel costs, and existing market and policy settings. It also assumes moderate growth in distributed energy resources aggregation, such that aggregated distributed batteries can be treated and operated as virtual power plants rather than operated to maximise their individual household's benefit.

46 AEMO, *Integrated system plan*, July 2018. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

47 TransGrid is the operator and manager of the NSW high voltage transmission network

48 In relation to Snowy Hydro transmission, the funding guarantee is contingent on Snowy 2.0 proceeding.

The South Australian government will also provide a finance guarantee of up to a further $10 million for this purpose.

64 On 21 December 2018, the AEMC published the final report of its inaugural *Coordination of generation and transmission investmen*t review. This report recommends a comprehensive reform package that better coordinates investment in renewable generation and transmission infrastructure, facilitating transmission and generation in the right place at the right time at an efficient cost. The AEMC's recommendations complement the recommendations made by the Energy Security Board (ESB) to the COAG Energy Council in December 2018 on how to "convert the ISP" into an "actionable strategic plan", and how the ISP projects could be delivered as quickly as possible.[49] The AEMC's recommendations provide further detail on how the ESB's recommendations can be implemented.

65 In January 2019, the AEMC published a consultation paper for the *Early implementation of ISP priority projects* rule change request submitted by the ESB. The priority projects detailed in the ISP are those that AEMO considers should be progressed as soon as possible because they provide immediate benefits to the NEM. If made, and in the absence of a dispute notice being lodged, the proposed rule aims to reduce the time between the completion of the regulatory investment test and the Australian Energy Regulator's (AER) approval of revenue for the QNI and VNI minor upgrade projects by six to eight months. This rule change request commences stage one of the reforms to the transmission framework that the AEMC recommended in the final report published as part of the *Coordination of generation and transmission investment* review.

66 In its *Coordination of generation and transmission investmen*t review, the AEMC also concluded that actioning the ISP needs to be paired with mechanisms necessary to allow generation to contribute to the enhancement of the networks and the management of congestion along it. The current access regime needs to evolve to allow the risk and cost of generation investment to complement planning and investment in transmission.[50] The AEMC is further examining the access regime and charging arrangements in 2019 through its *Coordination of generation and transmission investmen*t *implementation - access and charging* project.[51]

Network losses

67 When transferring power through a transmission network, some of the power is lost as heat energy. These losses increase as more generation connects in locations that are distant from load centres, as the power produced by the generation has to travel further to the load centre. Losses are also impacted by changes in power system flows, for example where generation retires in a region and requires more power to be imported from other regions.

68 It is necessary to account for these losses when operating the power system and the market. In the NEM, this is done by representing these losses with Marginal Loss Factors (MLFs),

49 ESB, *Integrated system plan; action plan*, December 2018.

50 For more information, see: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

51 For more information, see: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

which are calculated and applied annually by AEMO to the processes of generation dispatch and wholesale market revenue settlement.

69 MLFs are used to adjust the price of electricity in a NEM region, relative to the regional reference node[52], in a calculation that aims to recognise the difference between a generator's output and the energy that is actually delivered to consumers.[53] Generally speaking, generators with higher MLF values (that is a value that is close to one, or greater than one) will be dispatched first, and will receive a settlement payment for energy that is closer to the regional reference price.

70 Historically, MLFs do not change markedly from year to year. However, various factors, including recent changes in the power system, have meant that this process has resulted in significant year to year changes in some MLFs in some parts of the power system, with some generators seeing marked decreases in their MLFs.

71 The Panel has examined some of the changes in MLFs that have occurred across the NEM regions in the last three years. Over this period, a significant decrease in MLFs was observed in north and central Queensland. The general trend of a reduction in MLFs at connection points in central and northern Queensland could be explained by the retirement of large thermal units in the south of the NEM, coupled with increased entry of renewable generation and reduced demand in Queensland, which have resulted in changes to flows and degraded the MLFs for several Queensland generators.[54]

72 Figure 8 demonstrates MLFs change in north Queensland. It shows that over the last 20 years MLFs in North Queensland decreased significantly. Further, the decrease of MLFs in this region has notably accelerated in the recent years. According to AEMO, from 2017/18 to 2018/19, the planned connection of over 1,200 MW of new solar generation in north and central Queensland has led to MLFs falling by up to 12 per cent.[55]

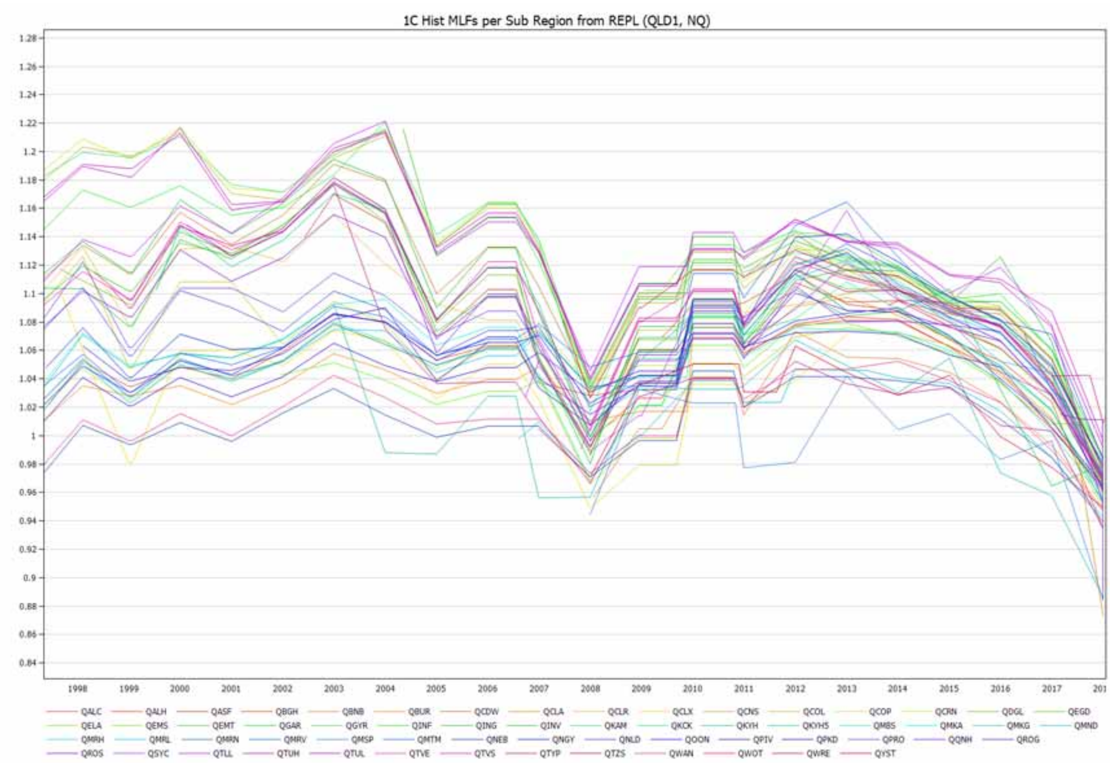
52 The reference point (or designated reference node) for setting a region's wholesale electricity price.

53 AEMO, *Integrated system plan*, July 2018, p. 53.

54 AEMO's *Regions and Marginal Loss Factors* reports. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

55 AEMO, *Integrated system plan*, July 2018, p. 53.

Figure 8: Change in MLFs in north Queensland from 1998 to 2018



Source: AEMO.

73 The Panel also notes on March 2019 AEMO, published draft MLF values for 2019/20 financial year. A significant reduction in MLF values occurred between 2018/19 and 2019/20.[56] This change is mainly driven by the unprecedented number of new generation connections expected to connect to the NEM in the coming year. This year's modelling done by AEMO includes 47 new connections providing approximately 5,600 MW of new capacity, mostly connecting in Victoria, New South Wales and Queensland. The majority of this new generation is connected to electrically weak areas of the network that are remote from the regional reference node, resulting in MLFs falling by large margins.

74 On 7 December 2018 and 5 February 2019, the AEMC received two rule change requests from Adani Renewables to amend the NER arrangements related to MLF application. Adani Renewables' main concerns are:

- Where a calculated forward-looking MLF is larger than the value that would be representative of the actual losses for a dispatch interval, a generator bears a risk of its bid price being greater than it would otherwise be for a more accurate/lower MLF. Such inaccuracy, according to Adani Renewables, leads to inefficient market outcomes and

56 For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

higher energy costs to consumers. Adani Renewables proposes to determine the MLFs according to the average loss factor methodology.[57]

- Under the current arrangements, any positive intra-regional settlement residue that accrues through the settlement process as a result of inaccuracies in relation to MLF's are distributed to transmission network providers. Adani Renewables proposes that generators should receive an equal share of any distribution of intra-regional settlement residue.[58]

75 The AEMC is also progressing the *Coordination of generation and transmission investment implementation - access and charging* review, which examines how generation and transmission investment may be more effectively coordinated, including how generators gain access to the transmission network. This longer-term work program will consider issues related to losses more holistically.[59]

Frequency control ancillary services markets

76 Ancillary services under clause 3.11.1 of the rules are defined as services that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality. There are two types of ancillary services provided in the NEM:

- Market ancillary services are acquired by AEMO as part of the spot market to provide the timely injection (or reduction) of active power to arrest a change in frequency. These services are generally referred to as frequency control ancillary services (FCAS). In the NEM, FCAS is sourced from eight markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised.
- Non-market ancillary services are network support and control ancillary services, system restart ancillary services and other services acquired by TNSPs and/or AEMO under connection agreements, network support agreements or through other direct procurement.

77 The cost of delivery of market ancillary services in the NEM has increased significantly over recent years (see the figure below). Total FCAS costs increased from roughly $25 million in 2012[60] to around $220 million in 2018[61]. The increase was observed for all the raise contingency and regulating services (the services that are used to increase the frequency during both normal operation and following a disturbance), and also for the lower regulating service (the service that is used to lower the frequency during normal operation).

57 For more information, see: https://www.aemc.gov.au/sites/default/files/2019-02/Rule%20change%20request.PDF

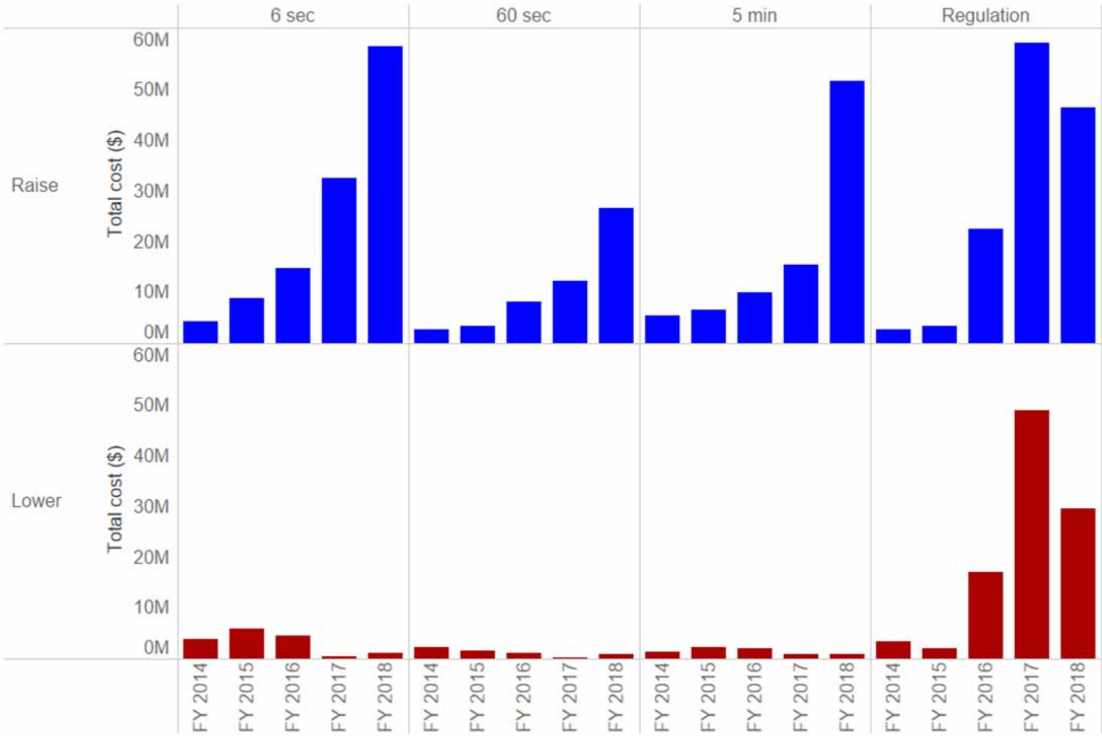
58 For more information, see: https://www.aemc.gov.au/rule-changes/intra-regional-settlement-residue-reallocation

59 For more information, see: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

60 AEMO, *Ancillary services payments and recovery*, October 2017.

61 AEMO's *Quarterly Energy Dynamics* reports.

Figure 9: NEM FCAS costs by service from 1 July 2013 to 30 June 2018



Source: AEMC analysis.

78 The Panel notes that a general reduction in the availability of FCAS may be linked to the following factors:[62]

- Energy provision and FCAS enablement are optimised within NEMDE. Therefore, generators tend to price FCAS at the opportunity cost of energy provision. The increase in wholesale prices and future contract market prices in some regions over 2017/18 may lead to the corresponding increase in the FCAS prices. Further, increasing demand (especially in Queensland due to the ramp up of liquefied natural gas projects) may incentivise participants to sell electricity at the wholesale market where prices are higher, rather than participate at the FCAS markets.
- Withdrawal of synchronous generation, which is typically operated in a way that allows it to offer capacity into FCAS markets, may reduce the physical supply of megawatts available to FCAS markets, leading to increases in FCAS prices. Several thermal generators that traditionally provided FCAS, such as the Northern Power Station in South Australia, have exited leading to less supply in the market. Until recently, renewable

62 The Panel notes that it has no quantitative evidence as to the extent to which each of these factors has driven the FCAS market outcomes.

generation has not provided these services. However, the Hornsdale Wind Farm and the Hornsdale Power Reserve (HPR) in South Australia now provide FCAS.[63] The Panel understands that Mussleroe Wind Farm in Tasmania is also undertaking trials to explore its ability to provide various FCAS.

- Regulatory interventions may also put an upward pressure on FCAS prices.
  - This includes AEMO's requirement for 35 MW of pre-contingent regulation FCAS procurement from South Australian providers that occurred from late 2015 to October 2018.
  - Tasmania has historically provided low cost global FCAS. However, unplanned outages on the Basslink Interconnector between Tasmania and the mainland (from December 2015 to June 2016 and again from March 2018 to June 2018) reduced global FCAS supply and put upward pressure on global FCAS costs. AEMO also imposed limits on the amount of regulation services Tasmania is permitted to provide to the mainland to better manage system security across the NEM.[64]

79 Despite this trend of increasing FCAS prices, in 2017/18 the costs of regulation FCAS decreased compared to 2016/17. Possible contributing factors to lower FCAS prices included:[65]

- Additional supply from new technologies towards the end of 2017 (the HPR and EnerNOC, the latter through the unbundling of the provision of FCAS to allow it to be provided by load[66]).
- The removal of the South Australian 35 MW FCAS constraint.

Security

80 Power system security is defined in the rules as the safe scheduling, operation and control of the power system in accordance with the power system security principles. These principles include maintaining the power system in a secure operating state and returning the power system to a secure operating state following a contingency event or a significant change in power system conditions, including a major supply disruption.

81 Clause 4.2.6(b)(1) of the rules requires AEMO to take all reasonable actions to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within 30 minutes. The key technical parameters that need to be managed to maintain a secure and satisfactory operating state are power flows, voltage, frequency, the rate at which these quantities change and the ability of the system to withstand faults.[67]

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63 AER, *Wholesale electricity market performance report*, December 2018, p. 16.

64 Ibid.

65 AEMO, *Quarterly Energy Dynamics - Q1 2018,* May 2018, p. 13.

66 On 1 July 2017, commenced the rule made by the AEMC that creates a new type of market participant who can do deals with energy users to offer demand response as a tool to help maintain power system security. The rule provides for a new type of market participant - a market ancillary service provider - to offer customers' loads into the FCAS markets. For more information see: https://www.aemc.gov.au/rule-changes/demand-response-mechanism

67 The NEM is considered to be in a secure operating state if the power system is a satisfactory operating state and will return to a satisfactory operating state following a credible contingency in accordance with the power system security standards. The power system security standards are the standards (other than the reliability standard and the system restart standard) governing power system security and reliability of the power system.

82 Maintaining the system in a secure operating state places tighter restrictions on operation than when it is in a satisfactory state. This is because a secure operating state means that the system will remain in a satisfactory state, even if there is a disturbance such as a contingency event. If the system is not in a secure operating state, the occurrence of a credible contingency event (an event which is reasonably possible) may have more severe consequences than would be generally acceptable. In such cases, a credible contingency event may lead to parts of the system exceeding satisfactory technical design specifications and may lead to some uncontrolled consumer load shedding.

83 The ongoing changes in the generation mix have implications for the security of the NEM. In particular, changes in the ratio of synchronous and asynchronous generation in the NEM may decrease the amount of physical inertia available and can also reduce system strength, both of which are key system security parameters. Reductions in availability of synchronous generation may also affect the ability of AEMO and network service providers to manage voltage and stability limits in the NEM, as synchronous generation traditionally provided this capability as an inherent aspect of operation.

84 These system services, such as the provision of inertia, system strength and voltage control, have traditionally been provided as a by-product of the operation of synchronous generation. As such, these system services have not been separately valued. However, the generation mix is shifting to include more asynchronous generation, which does not automatically produce these kinds of system services as a by product of operation.

85 Existing frameworks may therefore be inadequate to maintain the security of the power system in the future, as they do not recognise or place an explicit value on the provision of these historically unvalued services (aside from minimum levels necessary for a confidence in a secure operating state). They also do not recognise the overlaps and interactions between the various services, such as may exist between the provision of voltage control, system strength and inertia. This leads to the increasing number of instances when AEMO is forced to intervene in the market to direct generators on to provide these services, in order to maintain the system in a secure state.

86 The Panel considers that these system services should be identified and valued, so that they can be provided at least cost. While AEMO has been required to intervene to manage the system, the Panel notes that these interventions come at a significant cost to consumers. To the extent that the necessary system services are clearly identified and valued, the Panel considers that the market would be expected to provide them at a lower cost to consumers.

87 The Panel acknowledges the significant body of work completed and underway to address this issue:

- In September 2017, the AEMC published a final rule to place an obligation on transmission network service providers (TNSPs) to maintain minimum levels of system strength.[68] The rule commenced 1 July 2018. The framework in the final rule clearly allocates responsibility for system strength to the party who is best placed to manage the risks associated with fulfilling that responsibility – that is, the relevant TNSP.

68 For more information, see: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

- In September 2017, the AEMC published a final rule to place an obligation on TNSPs to procure minimum required levels of inertia or alternative frequency control services to meet these minimum levels.[69] The rule commenced 1 July 2018.
- In September 2017, the AEMC made a final rule that clarifies the scope and level of detail of model data that registered participants and connection applicants are required to submit to AEMO and network service providers.[70] By allowing AEMO and network service providers to access accurate model data, the final rule supports parties in fulfilling their obligations for maintaining system strength.
- In November 2017, the Panel has completed the first stage of its *Frequency operating standard* review.[71] This first stage addressed primarily technical issues and market framework changes, including the new category of protected contingency event in the frequency operating standard. The Panel is currently progressing the second stage of the review.
- In July 2018, the AEMC published a final report on the *Frequency control frameworks* review.[72] The report highlights several issues with the existing market and regulatory arrangements for frequency control, and makes recommendations on how they could be addressed.
- In September 2018, the AEMC made a final rule for AEMO to establish a register of distributed energy resources in the NEM, including small scale battery storage systems and residential rooftop PV.[73] The register will give network businesses and AEMO visibility of where distributed energy resources are connected to help in planning and operating the power system as it transforms.
- In September 2018, the AEMC published a rule determination on technical performance standards for generators seeking to connect to the national electricity grid, and the process for negotiating those standards.[74] The rule improves and clarifies the negotiating process to agree levels of technical performance when connecting generators, customers and market network service providers.

88 The Panel also notes the various work programs being progressed by the market bodies that will consider what else needs to be done to maintain system security in a changing power system environment. AEMO's forward work program will involve technical consideration of the various system needs, specifically what services will be required in what timeframes, as well as developing strategies for the management of these issues. The AEMC will also be progressing relevant work, including consideration of how security services may be procured in a coordinated manner by multiple parties as part of an improved access regime for the connection of generators to the power system, through the *Coordination of generation and transmission investment - access and charging review*. The AEMC will also consider the concept of system resilience, now that investigations by AEMO and the AER into 28

69 For more information, see: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque
70 For more information, see: http://www.aemc.gov.au/Rule-Changes/Generating-System-Model-Guidelines#
71 For more information, see: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard
72 For more information, see: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review
73 For more information, see: https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources
74 For more information, see: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

September 2016 South Australian Black System event are largely complete. Further, the AEMC will progress the rule change request expected from AEMO to increase primary frequency services.

89 While the Panel notes this substantial body of work underway, the Panel considers that there are certain areas where particular monitoring is required, to be certain that critical system services will be delivered as and when they are needed. These include:

- frequency performance
- system strength, and
- voltage limits.

The Panel intends to monitor progress and report against these key priority areas in the 2019 AMPR.

Frequency performance

90 A key indicator of the security performance of the NEM is the extent to which system frequency has met the requirements of the frequency operating standard (FOS).

91 Controlling and maintaining a stable system frequency within a narrow range, close to 50Hz, increases the resilience of the system to non-credible contingency events. In the event of a severe non-credible or multiple contingency event, frequency that is already outside the normal frequency operating band may deviate even further from 50Hz, potentially leading to load shedding. The likelihood that the system will recover from the contingency event increases when frequency is within the normal operating band.

92 Frequency performance of the NEM showed mixed performance in 2017/18. During this period, the FOS was only partly met in both the mainland and in Tasmania. The FOS consists of several different measures of frequency performance, only some of which were met.[75]

93 While the mainland frequency remained within the normal operating frequency band more than 99 per cent of the time for each month of the reporting period (as per the requirements of the FOS), there were 50 events where system frequency took longer than allowed in the FOS to be returned to the normal operating frequency band and therefore that did not meet all the requirements of the standard. Further, in 2017/18 the mainland system operated outside the normal operating frequency band for 192,380 seconds. This is an increase from 2016/17 (93,032 seconds) and 2015/16 (25,592 seconds).

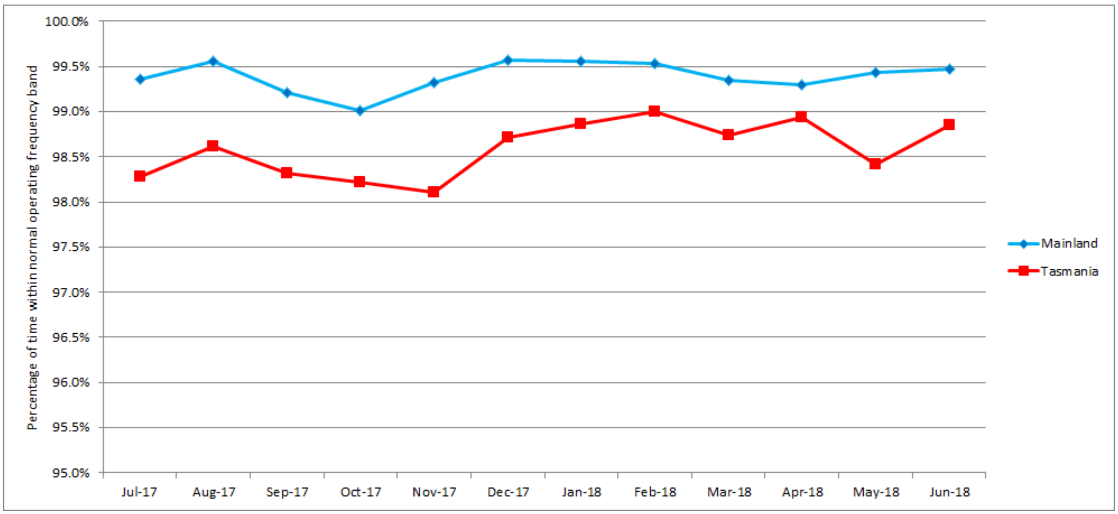
94 In Tasmania, frequency performance did not meet both of these FOS requirements,[76] with system frequency outside of the normal operating frequency band for more than 99 per cent of the time for 11 months in 2017/18 (see Figure 10 below). There were also 295 events

75 The elements of the FOS relevant to normal operation of the power system include: 1) the range of allowable frequencies in bands corresponding to the operating state of the power system (the current requirement is that for 99 per cent of the time, the power system is maintained within the range of 49.85 – 50.15Hz (the normal operating frequency band), over any 30 day period), and 2) times for the stabilisation and recovery of the power system frequency following a frequency deviation (the current requirement is that during normal operation, if the power system frequency deviates outside the normal band, it must be returned to the normal band within five minutes).

76 The current frequency operating standard for the NEM mainland and Tasmania define different frequency boundaries that apply for different types of contingency events. This is due to the specific tolerances of Tasmanian generators to frequency variations and to limit the cost of Frequency control ancillary services (FCAS) procurement.

where frequency took longer than allowed in the FOS to be returned to the normal operating frequency band. Further, in 2017/18 Tasmania operated outside the normal operating frequency band for 446,708 seconds. This is an increase from 2016/17 (338,992 seconds) and from 2015/16 (398,544 seconds).

Figure 10: Percentage of time within normal operating frequency band



Source: AEMO.

95 The frequency performance of the NEM can also be illustrated by reference to a significant system security event that occurred in the NEM on 25 August 2018.[77] The NSW-QLD interconnector (QNI) tripped, separating the Queensland region from the rest of the NEM power system. This resulted in the separation of the South Australia region from the rest of the NEM, and under-frequency load shedding in the Victoria and New South Wales regions.

96 AEMO has identified that while most power system equipment operated within the standards set under the NER, the aggregated response did not meet expectations for power system resilience. AEMO's analysis highlights a decline in frequency control capability and system resilience to events larger than single credible contingencies in the NEM.[78] In particular, AEMO highlighted that the lack of primary frequency control capability played a key role in the poor frequency performance of the NEM during the event.[79]

97 AEMO has provided further analysis of the extent to which primary frequency control capability has reduced in the NEM. Over 2017, AEMO conducted a survey of generators to explore frequency responsiveness of the NEM generating fleet.

77 This event falls outside of the reporting period for this AMPR. However, the Panel has included some high level analysis of it in this report to illustrate the extent of potential supply impacts for consumers following major security events in the power system. The event will be also discussed in more detail in the 2019 AMPR.

78 AEMO, *Queensland and South Australia system separation on 25 August 2018*, final report, January 2019, p. 3.

79 Primary frequency control services provide the initial response to frequency disturbances. They react automatically and almost instantaneously to locally measured changes in system frequency outside predetermined set points. A primary frequency response is an automatic change in active power generated (or consumed) by a generator (or load) in response to a locally measured change in system frequency.

98 For the survey purposes, AEMO categorised settings as follows:

- Continuous frequency support with +/-50 mhz deadband - that is, a continuous response from generators when the frequency was within the range of 49.95Hz - 50.05Hz. [80]
- Continuous frequency support with +/-100 mhz deadband - that is, a continuous response from generators when the frequency was within the range of 49.90Hz - 50.10Hz.
- Wider deadbands, no frequency response, or unknown response characteristics.

99 The survey results are as follows:

Table 1: Generator survey summary

STATE	<=50 MHZ (TOTAL MW REGISTERED CAPACITY)	<=100 MHZ (TOTAL MW REGISTERED CAPACITY)	WIDER OR UNKNOWN (TOTAL MW REGISTERED CAPACITY)
NEM total	9,514	3,632	40,671
Queensland	304	2,575	11,706
New South Wales	5,000	0	13,552
Victoria	3,202	0	8,449
South Australia	713	0	5,115
Tasmania	295	1,057	1,849

Source: AEMO.
Note: Totals may differ slightly to figures elsewhere due to filtering and rounding.

100 This analysis shows that around 13,000 MW of the generation capacity surveyed had deadbands set within the normal operating frequency band, with approximately 40,671 MW of capacity had deadbands set outside of the normal band and would not therefore be considered frequency-responsive within the normal range. A wider deadband means that these generators will not provide an automatic response to a frequency disturbance until frequency has moved a significant distance away from the nominal 50Hz, or at least until the frequency has moved outside of whatever deadband settings the generator has implemented.

101 AEMO also notes that the NEM is increasingly relying upon emergency frequency control schemes to respond to non-credible events, due to reduced primary frequency control from generators. However, there are some challenges to the operation of those schemes. Specifically, as distributed solar PV units are installed in distribution networks, transmission network service providers and AEMO have a limited view of the actual state of load feeders in

80 These deadbands represent the frequency responsiveness of the generator. This means that the generator will only change its active power output in response to power system frequency, when power system frequency is outside the limits of the generator's deadband. The current requirement in the FOS is that, for 99 per cent of the time over any 30-day period, the power system is maintained within the range of 49.85 - 50.15Hz, which is defined as the "normal operating frequency band".

these networks. Emergency frequency control schemes rely on visibilities of loads and generation as that is how these schemes have been designed. Residential rooftop solar PV may blur this visibility substantially. If an emergency frequency control scheme has been activated, not only load but the distributed generation may also be disconnected. That may lead to a further decrease in frequency and as a result the disconnected loads may be considerably higher than intended.

Work underway

102 The Panel notes that the AEMC and AEMO are currently progressing various work programs which are considering measures to improve the frequency control performance of the NEM. Specifically, the AEMC and AEMO are working together to consider the introduction of a suitable interim measure to deliver sufficient primary frequency control in the NEM by Q3 2019. The AEMC and AEMO will also work on a permanent mechanism to secure adequate primary frequency control by mid-2020.

103 AEMO is also progressing work considering how FCAS should be procured across the NEM. The allocation of contingency and regulation FCAS reserves across the NEM does not usually include any need for geographic distribution. In relation to secondary frequency control, AEMO will investigate the opportunity for automation of reconfiguring AEMO's systems after separation and large system events. AEMO will report on options to industry in Q2 2019. AEMO will also investigate whether a minimum regional FCAS requirement is feasible, or whether there may be scope to manage frequency requirements arising from non-credible regional separation under the protected event framework in the NER, after interim primary frequency control outcomes at the end of Q3 2019.

104 AEMO has also advised that the Market Ancillary Services Specification (MASS) has many components that require update and review, particularly to incorporate suitable arrangements for distributed resources and other emerging technologies.[81] As recommended by the AEMC in its *Frequency control frameworks review* final report, AEMO will consult with stakeholders to review the MASS. This will be conducted in stages to allow implementation of urgent updates.

105 In relation to emergency frequency control schemes, AEMO has started a review of NEM under-frequency load shedding schemes starting with South Australia being the most urgent. AEMO is also developing proposals to mitigate the impact of under-frequency load shedding schemes cascading failure.

106 As noted above, as part of its work in developing the next annual market performance review, the Panel will monitor the market bodies' work programs, and consider whether they are likely to effectively address the issue of deteriorating frequency performance in the NEM.

107 The Panel also notes that aside from these work streams being progressed by the AEMC and AEMO, there is evidence that market participants are utilising emerging technologies to provide new frequency control services. Some of these market led projects are discussed in

81 The MASS underlies the provision of market ancillary services (i.e. FCAS) in the NEM. It sets out the detailed specification for each of the market ancillary services and how a market participant's performance is measured and verified when providing these services.

more detail in chapter 4 of this report.

System strength

108 System strength is a property of the power system that resists changes in voltage in response to a change in loading conditions. It is also related to the level of current that can flow into a short circuit at a particular point in the power system, with low system strength conditions corresponding to low levels of available fault current. This availability of fault current affects the ability of system protection systems to operate correctly and the stability and dynamics of generator control systems. The supportive characteristics of synchronous generation, as related to system strength, are not typically provided by power electronic converter-connected, asynchronous generation technologies.

109 It is important to maintain certain levels of system strength. Areas with low system strength levels exhibit deeper voltage dips and slower voltage recovery over a wider area of the network following a fault, switching event, or change in load or generation. Low system strength can also lead to different instability problems or adverse interactions. These range from local connection power instability to wider network issues, potentially impacting a range of power system components including synchronous and asynchronous generators, protection systems, and dynamic reactive devices.

110 Low levels of system strength have been identified as an emerging issue in north Queensland, south-west New South Wales, north-western Victoria, and South Australia.[82] AEMO also identified a Network Support and Control Ancillary Services (NSCAS) gap in South Australia for system strength in the *2016 National transmission network development plan* (NTNDP).[83] To address the issue, ElectraNet[84] determined that the installation of synchronous condensers on the network is the most efficient and least cost option.[85] ElectraNet plans to deliver a solution to improve system strength in South Australia by end 2020.[86]

111 In addition to the directions being issued in South Australia, system strength related issues are emerging in other regions of the NEM. For example, on 17 November 2018, AEMO issued a direction in Victoria to maintain sufficient system strength. To date, AEMO has not declared a shortfall in system strength in any NEM region other than South Australia. However, the recent direction in Victoria may indicate an emerging system strength issue in that region and could potentially be an indication of nascent system strength issues throughout the rest of the NEM.

112 System strength shortfalls can be expected to continue as existing synchronous generators retire and as installation of residential scale solar continues to grow. This is because residential rooftop PV reduces operational demand, which impacts on spot prices and can therefore act to displace synchronous generators in dispatch, reducing the available supply of

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82 AEMO, *Integrated system plan*, July 2018, p. 73.

83 AEMO, *2016 National transmission network development plan*, December 2016, p. 8. AEMO confirmed this gap in subsequent updates in September 2017 and October 2017.

84 ElectraNet is the operator and manager of the South Australia high voltage transmission network.

85 ElectraNet, *Strengthening South Australia's power system*, accessed on 21 November 2018, at: https://www.electranet.com.au/what-we-do/projects/power-system-strength/

86 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 5.

fault current from synchronous generation.

113 Similarly, increased penetration of new large scale asynchronous generation (which usually has lower short run variable costs than traditional forms of synchronous generation) can be expected to exacerbate this displacement effect, increasing the extent of this system strength shortfall.[87]

114 To manage system strength in South Australia in the meantime, AEMO made a number of interventions in the market to ensure that the system remains in a secure operating state. In doing so, AEMO has made use of constraints and directions.

- Constraints involve changing what generators are dispatched, and can impose costs on consumers by changing the wholesale market price.
- Directions involve telling specific generators that they must run, even if it is not economic for them to do so, which can impose costs on consumers through the compensation that these generators are then allowed to claim.

115 AEMO often applies these tools when high levels of asynchronous generation output coincide with periods of low to moderate demand, resulting in low spot prices and synchronous generators bidding unavailable for commercial reasons.

Constraints

116 AEMO continuously selects resources to achieve security-constrained economic dispatch. This means that at all times, AEMO operates the system to balance supply and demand for power using the most economic resources available, consistent with maintaining a secure and reliable system. [88]

117 For the purposes of managing the security of the system and accounting for system strength requirements, AEMO intervenes in the market by using constraints in South Australia to restrict the dispatch of some asynchronous generation to levels typically between 1,295 MW and 1,460 MW. This allows for a minimum number of synchronous generators being online for system strength requirements. Figure 11 demonstrates the levels of asynchronous generation curtailment[89] in South Australia from Q2 2017 to Q2 2018.

118 The Panel recognises that the imposition of these constraints can create material costs for consumers. This is because the application of these constraints to keep the system in a secure operating state can also have the effect of increasing wholesale market prices. By restricting output from asynchronous generators, which traditionally bid into the market at low prices, wholesale market prices are likely to be higher, due to the fact that synchronous generators with higher marginal costs will remain online during periods of low demand.

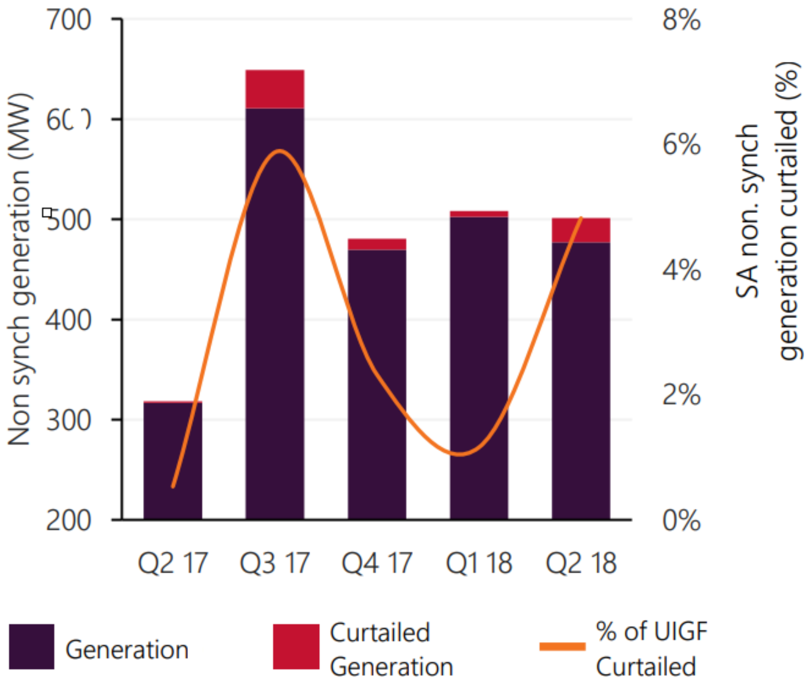
87 However, it should also be noted that the connection of these generators themselves should not directly impact the size of a system strength shortfall, given the 'do no harm' obligation introduced by the AEMC as part of the *Managing power system fault levels* rule change. The 'do no harm' obligation introduced by the AEMC is discussed further in this report.

88 AEMO, *Advice to Commonwealth government on dispatchable capability*, September 2017, p. 2.

89 This figure is based on AEMO's unconstrained intermittent generation forecast (UIGF). AEMO is required to prepare forecasts of the available capacity of semi-scheduled generators, in order to schedule sufficient generation in the dispatch process. This is known as the UIGF. AEMO estimates UIGF based on the outputs of the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting

According to AEMO, in the 2017 calendar year the total cumulative marginal value[90] of system strength constraints in South Australia was $4.75 million.[91]

Figure 11: Curtailment of asynchronous generation



Source: AEMO, *Quarterly Energy Dynamics*, Q2 2018.
Note: This figure is based on AEMO's unconstrained intermittent generation forecast (UIGF). AEMO is required to prepare forecasts of the available capacity of semi-scheduled generators, in order to schedule sufficient generation in the dispatch process. This is known as the UIGF. AEMO estimates UIGF based on the outputs of the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting

Directions

119 In addition to applying constraints, AEMO also issues directions. A direction may include instructions such as requiring a specific generator to commence operation and run at a given level of output for a specified amount of time.

120 The number of direction events in 2017/18 was the highest of the past ten years (see Figure 12). The number of direction events was four times higher than in the past financial year (32 in 2017/18 compared to eight in 2016/17).

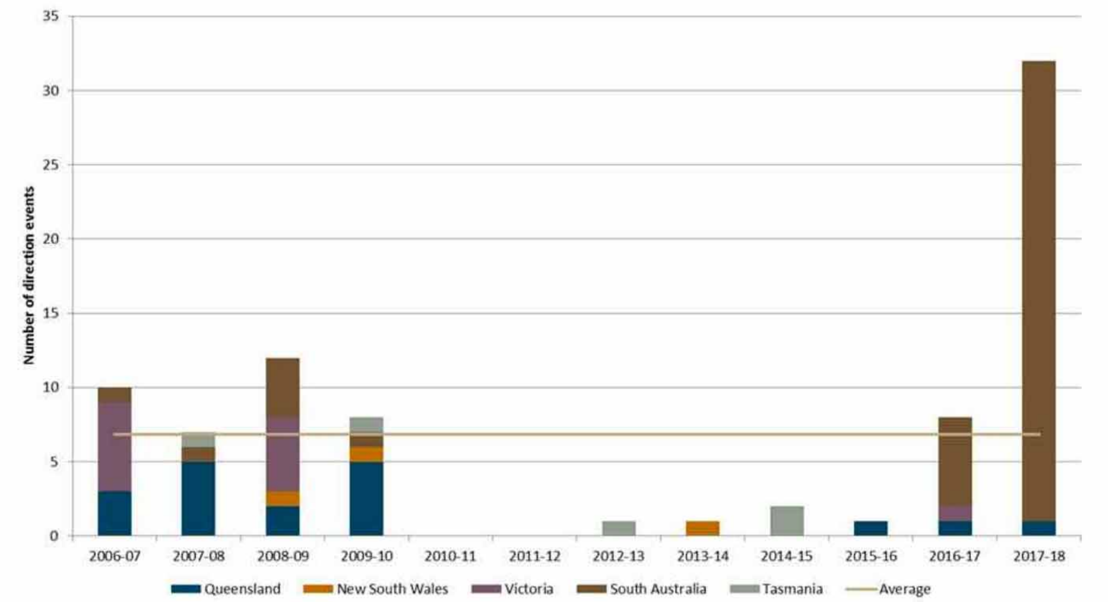
121 AEMO notified the Panel that in 2017/18, it issued a total of 101 individual power system security directions. Most of the directions that have occurred to date, and that account for

90 The marginal value of a constraint is the effect on total dispatch costs of alleviating that constraint by 1 megawatt (MW). The cumulative marginal value is the sum of these values over a given time period. It is important to note that the marginal value of a constraint is only a partial representation of the total costs of a constraint. That is, it does not follow that relaxing a constraint by more than the marginal megawatt will automatically result in the same degree of value for the subsequent megawatts.

91 AEMO, *NEM Constraint report 2017 summary data*, July 2018.

the increased number of directions in this period, were to ensure adequate system strength for secure operation of the South Australian power system. In South Australia, directions are used to meet the security limits by ensuring that certain combinations of synchronous generators are in service at all times to maintain sufficient levels of system strength.

Figure 12: Direction events in the NEM



Source: AEMO.

122 The Panel notes that a direction event may include multiple individual directions to different generators.[92] For instance, between 23 April and 14 May 2018 (21 days) a single direction event occurred in South Australia. Within this single direction event, 27 individual directions were issued to market participants to maintain power system security.

123 The proportion of time in which directions have been in place in the NEM has also risen noticeably over the last year. For 2017/18, a direction was in force in the NEM on average approximately 20 per cent of the time, up from one per cent in 2016/17.

124 These interventions impose material costs on consumers. According to AEMO, the cost[93] of the system strength directions was \$7.05 million in Q2 2018 and \$7.4 million[94] in Q3 2018.[95] ElectraNet also stated that ongoing direction compensation costs are currently estimated to be approximately \$34 million per annum in net terms (equivalent to around \$3 million per

92 The Panel notes that there is no prescribed method by which to determine the appropriate length of AEMO direction events. These can range from a few hours to, in one case, 21 days (in April-May 2018).

93 Based on Compensation Recovery Amount (provisional amount). Compensation Recovery Amount is recovered from the NEM for a direction. It is equal to the sum of compensation amount paid by AEMO, independent expert fee and interest amount. Interest is determined at the average bank bill rate between the settlement date corresponding to the direction date and the settlement date of the final determination week. AEMO, *NEM direction compensation recovery*, January 2015.

94 Compensation costs in respect of directions are funded by market customers (and thus end consumers), having regard for the relative benefit each region receives as a result of the direction and the market share of each market customer.

95 AEMO, *Quarterly Energy Dynamics*, Q3 2018, p. 7.

month).[96] This excludes the broader impact of intervention pricing[97] on wholesale market prices through AEMO's direction process, which represents an additional cost ultimately borne by customers. In its *Addressing the system strength gap in SA* report, ElectraNet stated that the cost impact of intervention pricing on wholesale market outcomes as a result of issuing directions for system strength as at September 2018[98] exceeds $270 million.[99] This is additional to the impacts of constraining wind generation.[100]

125 The issue of declining system strength has been addressed with the new framework established by the AEMC's *Managing power system fault levels* rule. The new framework commenced on 1 July 2018. Under this rule:[101]

- Transmission Network Service Providers (TNSP) are required to procure the minimum levels of system strength to maintain the system in a secure operating state. In accordance with this obligation, ElectraNet plans to install synchronous condensers on the network to improve system strength in South Australia by 2020.[102]
- New connecting generators are required to 'do no harm' to the level of system strength necessary to maintain the security of the power system. Across the NEM, new connecting generators are currently complying with this new process.

Work underway

126 The AEMC has commenced work on the *Investigation into interventions mechanisms and system strength* project, which will evaluate the effectiveness of the interventions framework in light of the increasing use of directions by AEMO to manage system security. This review will also assess the effectiveness of the frameworks introduced by the AEMC's *Managing*

96 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 20. The cost of $34 million does not represent the total cost of directing generators in South Australia to ensure adequate system strength. It is also appropriate to take into account trading amounts that would otherwise be paid to those generators and wider impacts on wholesale market prices. This is discussed in more detail in Chapter 7 of the consultation paper for the AEMC's *Investigation into intervention mechanisms and system strength in the NEM*. Source: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

97 Where a direction has been issued, AEMO will apply intervention pricing in accordance with its Intervention Pricing Methodology. Intervention pricing is triggered when AEMO intervenes in the market by activating the RERT or issuing a direction. Intervention pricing determines the price at which the market clears during an AEMO intervention event, while compensation is a separate process and is paid only to certain parties – those who are directed to provide services and those who are affected (i.e. dispatched differently) due to the direction. Compensation is payable regardless of whether intervention pricing is implemented.

98 While the basis on which this figure is calculated is not set out in the report, the Panel understands that it reflects the difference between spot prices as set by the intervention pricing run and prices produced by the dispatch run, averaged over the period April 2017 to September 2018.

99 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 21. While the basis of this $270 million figure is not set out in the ElectraNet report, the Panel surmises that it reflects the difference between spot prices as set by the "intervention pricing run" and prices produced by the "dispatch run" when system strength directions are in effect, averaged over the period from April 2017 to September 2018. If this is the case, it is likely that this figure represents an upper limit of the impact of intervention pricing on wholesale energy prices. This is because the market could be expected to self-correct at least to some degree if intervention pricing was not applied and prices were allowed to fall in response to additional generation coming online in response to a system strength direction. For example, in South Australia, removing intervention pricing and allowing the spot price to fall to reflect the supply demand balance that follows from the direction could be expected to prompt generators to rebid or withdraw from the market rather than pay to generate when prices fall to strongly negative levels. Secondly, higher spot prices typically do not translate immediately or directly into higher prices for consumers. This is because most retailers have hedge contracts with generators in order to manage wholesale price volatility. However, contract prices are negotiated having regard for expectations about future spot prices. As such, higher spot prices can be expected to put upward pressure on contract prices and thus wholesale energy costs. For more information, see: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

100 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 21.

101 See: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

102 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 5.

power system fault levels rule which commenced on 1 July 2018.[103]

127 Further, the AEMC has received four rule change requests that seek to improve processes related to AEMO's interventions in the market, for example the way generators and demand response providers are compensated after a direction from AEMO to help maintain system security or reliability.[104]

128 The AEMC also considers that the current access regime needs to evolve to allow the risk and cost of generation investment to evolve to better complement planning and investment in transmission. This is being progressed through the *Coordination of generation and transmission investment – access and charging review*. The purpose of the reforms is to improve the coordination between the generation and transmission sector. This includes considering how these reforms will better allow generators to coordinate on their connections, including the provision of certain services such as system strength.

129 In relation to system strength, AEMO will review the current management of system strength in order to identify other possible solutions. This may include: re-engineering existing assets such as synchronous generators to operate as synchronous condensers when not required for energy or/and encouraging system strength levels above the minimum requirement, to provide other system benefits.

130 AEMO will also undertake the following measures to improve system strength:

- complete the development of suitable simulation models for system strength studies
- determine minimum requirements for system strength in each region, and likelihood of shortfalls
- conduct technical analysis to determine the need for any new types of security services, including grid formation and system restart and restoration
- review the Emergency APD Portland Tripping scheme to identify improvements by 1 July 2019; review other existing AC interconnector schemes with TNSPs, to determine whether their performance remains fit for purpose in the changing environment and are properly co-ordinated, by Q1 2020.

131 The Panel will further monitor whether the AEMC's and AEMO's work programs outlined above address the system strength issues identified in this report.

Voltage limits

132 The voltage of the power system must be maintained within defined limits, to ensure that power can be effectively transferred from generation sources to loads. System voltages are controlled through the injection and absorption of reactive power.[105]

103 For more information, see: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

104 For more information, see: https://www.aemc.gov.au/sites/default/files/2019-02/System%20security%20and%20reliability%20action%20plan.pdf

105 Power in alternating current networks comes in two different types; active power and reactive power. Active power accomplishes useful work at the point of end use through the delivery of energy services (heat, lighting, motion). Reactive power, on the other hand, does not directly deliver energy services to network users. Instead, reactive power is necessary to support the movement of active power through electricity networks. Reactive power capability, and its effective control, is necessary to support the control of voltage levels on the power system. Voltage therefore reflects the dynamic balance between injection and absorption of reactive power in the local area of the power system. Shortfalls in reactive power capability can therefore lead to voltage instability or collapse.

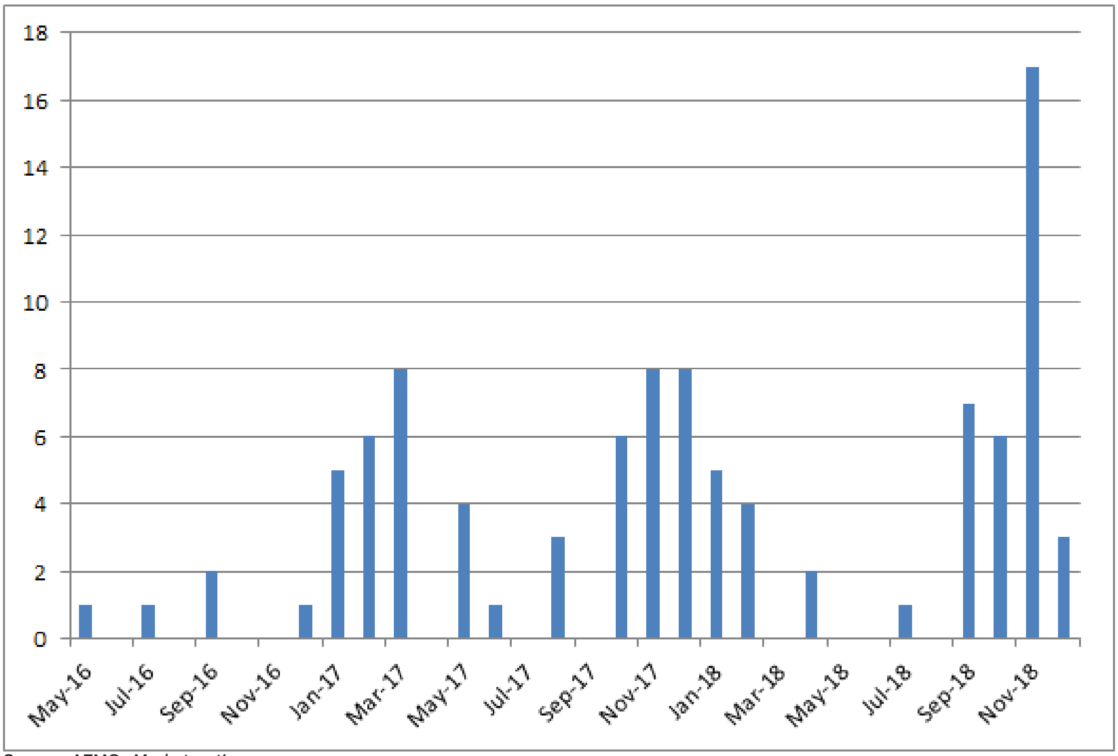
133 In certain states a need has been identified for additional reactive support[106] to maintain transmission system voltages within operational limits during minimum demand periods. AEMO has noted that voltage regulation becomes more challenging with increased penetration of residential rooftop PV systems.

134 In Victoria and South Australia, material over voltage issues have been identified that have required AEMO to manually intervene in the market to maintain system security. AEMO is currently managing over voltages with short term de-energisation of high voltage lines and/or issuing a direction to a generator to return or remain in service to absorb reactive power and assist with voltage control. In Victoria, between March 2017 and May 2018, the de-energisation of 500 kV lines was implemented more than 40 times during light load periods to manage high voltage, and de-energisation of two 500 kV lines was required five times during very light load periods.[107] Figure 13 shows the number of times de-energisation of lines was implemented in Victoria between May 2016 and December 2018. The figure demonstrates that the number of times 500 kV transmission lines were de-energised increased significantly in November 2018.

106 Lightly loaded transmission lines produce reactive power. The higher the transmission line operating voltage, and the longer the line, the higher the amount of reactive power that could be discharged into the power system. Excessive generation of reactive power can create unacceptable over-voltages. Synchronous generators have the ability to both generate and absorb reactive power.

107 AEMO, *Victorian reactive power support: project specification consultation report,* May 2018, p. 7.

Figure 13: **Number of times 500 kV transmission lines were de-energised to manage voltage in Victoria**



Source: AEMO, *Market notices*.

135 In November 2018, a particularly significant voltage control incident occurred in Victoria. This incident, which required the de-energisation of three 500 kV lines for the first time in the NEM, provides an illustration of these emerging voltage control issues.[108] In response to this event, in December 2018 AEMO declared an NSCAS gap for voltage control in Victoria. AEMO, in its Victorian planning role, entered into contractual arrangements with synchronous generators for voltage support.[109]

136 While line de-energisation can provide a temporary solution to overvoltages, it can also reduce the overall reliability and stability of the system, by reducing the number of flow paths available for the transmission of power.

Work underway

137 In May 2018, AEMO commenced a Regulatory Investment Test for Transmission (RIT-T) for increasing reactive power support in Victoria to help manage voltage at times of low grid

108 As this event falls outside the 2018 AMPR review period, the Panel will discuss it in greater detail in the 2019 AMPR.

109 AEMO, *2018 National transmission network development plan*, December 2018, p. 21.

demand.[110] In July 2018, AEMO published a request for information seeking non-network options to relieve the high voltages in the Victorian transmission network during low demand periods. The next step of the RIT-T process is the full options analysis and publication of the Project Assessment Draft Report.

138 The Panel notes that AEMO recognises the need for more options to manage high voltages in the transmission network, caused by reduction in operational demand during light load conditions and displacement or retirement of synchronous generators together with their reactive power capabilities to regulate voltage. AEMO has developed a work program to address challenges related to voltage control. The work program, among other things, includes:

- Collaboration with TNSPs to explore and implement short term operational measures to manage system voltages during light load conditions. This has a particular focus in Victoria at present.
- Implementation of short term non-market ancillary service contracts in Victoria, while regulatory processes continue in parallel to deliver permanent network solutions.
- Coordination of a program of work with TNSPs to collaboratively conduct system studies to identify emerging voltage control and reactive power requirements over the next 1-10 years.
- Development of a NEM-wide strategy for voltage management by the end of 2019.

139 The Panel will consider monitoring whether the measures outlined above are adequate to address identified voltage control issues.

Instances when the power system was outside secure limits for more than 30 minutes

140 In relation to the security of the power system, the Panel also reports on the instances when the power system was outside secure limits for more than 30 minutes.

141 There was one event of the power system being operated outside its secure limits for greater than 30 minutes (see Figure 14). The event occurred on 18 January 2018 in Victoria and followed switching actions taken to manage contingency overloads indicated after a transformer failure.[111]

142 The figure below demonstrates that in 2017/18 there was a decrease in the number of times secure operating limits were exceeded for greater than 30 minutes.[112]

143 AEMO notes that there is no trend or pattern in the number of these events. The power system can become insecure for many reasons, which may or may not combine with other pre-existing or subsequently arising conditions or actions. According to AEMO, in the majority of cases where historically recovery has exceeded 30 minutes, AEMO could not have done anything differently to reduce the recovery time because of the particular combination of

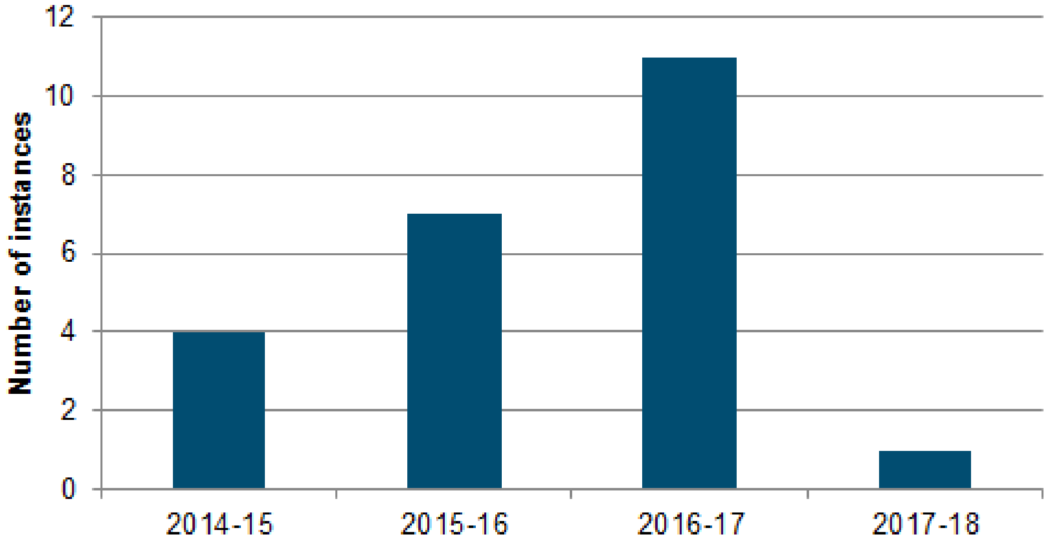
110 AEMO, *Victorian reactive power support: project specification consultation report*, May 2018. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission

111 The event is discussed in more detail in chapter 5.

112 There were 11 such instances in 2016/17.

events that coincided. It is expected that the number of these events will continue to vary considerably over the years. The Panel considers that any apparent trends identified in the information set out in the figure below should be viewed in light of AEMO's comment.

Figure 14: Number of times the operating system was not in a secure operating state for greater than 30 minutes



Source: AEMO.

Reliability

144 At a wholesale level, reliability is about having sufficient generation, demand side response, and interconnector capacity in the system to generate and transport electricity to meet consumer demand.

145 During the reporting period, there was no unserved energy in the NEM.

146 However, as with security related issues, the Panel notes that AEMO manually intervened in the market to maintain reliability during the reporting period. The Reliability and Emergency Reserve Trader (RERT) was activated on two occasions to maintain the power system in a reliable operating state. Prior to 2017/18, the RERT had only been procured three times and had never been activated. Consumers bore a cost of $51.99 million in 2017/18 for the activation of the RERT.[113]

147 The Panel acknowledges that there has been a significant body of work completed in 2017/18 to address reliability issues. The progress against the full list of *Finkel Review*[114] recommendations is reflected in the appendix to the ESB's *Health of the NEM* report.[115] The

113 AEMO, *RERT 2017-18 cost update*, 2018, p. 1. Available at: http:// https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/RERT-Update—-cost-of-RERT-2017-18.pdf

114 Commonwealth of Australia, *Independent review into the future security of the National Electricity Market - Blueprint for the Future*, June 2017.

AEMC's work program is set out in appendix M.

148 The Panel notes the significant volume of work underway that is continuing to consider how to improve reliability of the electricity supply in the NEM. This includes:

- the ESB's *Retailer reliability obligation*, which aims to incentivise retailers, and other large users, to invest in dispatchable electricity generation in the NEM regions, where it is expected there will be a gap between generation and forecast peak demand.
- the AEMC's *Enhancement to the reliability and emergency reserve trader* rule change, which seeks broad changes to the NEM's emergency reserve.
- the AEMC's *Wholesale demand response mechanism* rule change, which seeks to introduce a new mechanism, register or separate market to enable more wholesale demand response in the NEM.
- *AEMC/AEMO/AER virtual power plant (VPP) trial*, which will inform changes to regulatory frameworks and operational processes so VPPs can play a bigger role in the energy market.
- The AEMC's *Short term forward market* rule change, which will consider providing an AEMO-operated platform to enable market participants to contract for electricity in the week leading up to dispatch, to help enable more demand response.

149 There have also been a number of recent relevant government initiatives, which are discussed in chapter 4.

150 The Panel notes the following key reliability trends and outcomes during 2017/18.

Supply interruptions

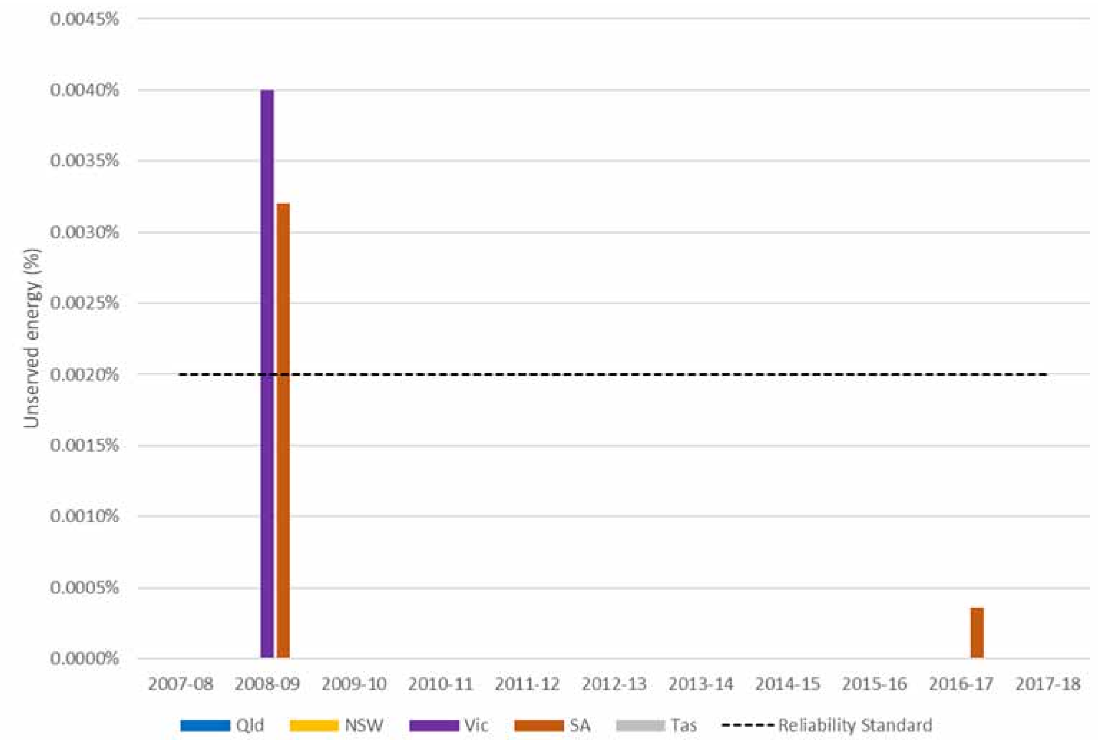
151 In 2017/18, there was no unserved energy in the NEM from generation or interconnection inadequacy.

152 The chart below shows that, in the past decade, there have been three occasions where there was unserved energy: in Victoria and South Australia in 2008/09, and in South Australia in 2016/17 (see the figure below).[116]

115 For more information, see: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/the%20health%20of%20the%20national%20electricity%20market%20-%202018.pdf

116 The Panel acknowledges the load shedding events that occurred in Victoria on 24 and 25 January 2019. Analysis of this event has not yet been completed and so the Panel is not able to comment in detail on these events in this AMPR. The Panel intends to cover these load shedding events in detail in the 2019 AMPR, once AEMO has undertaken all its analysis and reporting functions.

Figure 15: Unserved energy in the NEM



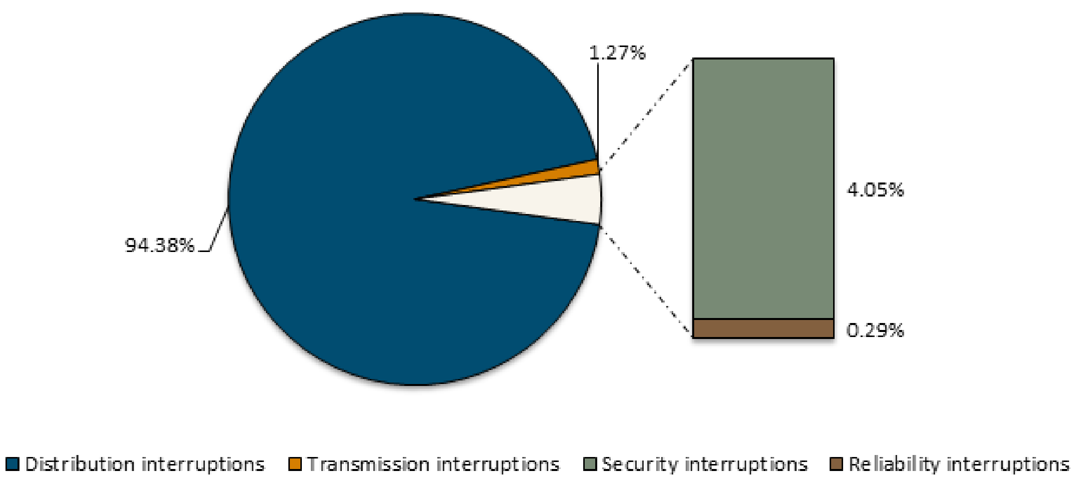
Source: AEMO.

153 The figure below shows the interruptions of supply arising from incidents involving reliability, security, transmission networks and distribution networks from 2007/08 to 2017/18. The Panel notes that interruptions to consumer supply relating to the reliability of generators and interconnectors have historically represented a very small amount of all supply interruptions experienced by customers.

154 Over the period, only about 0.29 per cent of total supply interruptions (in terms of GWh) were the result of reliability events (brown area of the chart). Security events also represented a small portion (grey area) of all supply interruptions, at 4.05 per cent.

155 Estimates show that the events on distribution networks are responsible for about 94.38 per cent of supply interruptions (blue area of chart). The distribution network represents the largest set of infrastructure in the electricity supply chain, with many possible points of failure. Standards relating to distribution networks are set by jurisdictions. Distribution and transmission outages tend to be spread over the year (though higher rates of outages occur at times of peak demand), whereas wholesale reliability issues almost always occur at times of peak stress on the system when demand is high due to extreme weather.

Figure 16: Sources of supply interruptions in the NEM from 2007/08 to 2017/18



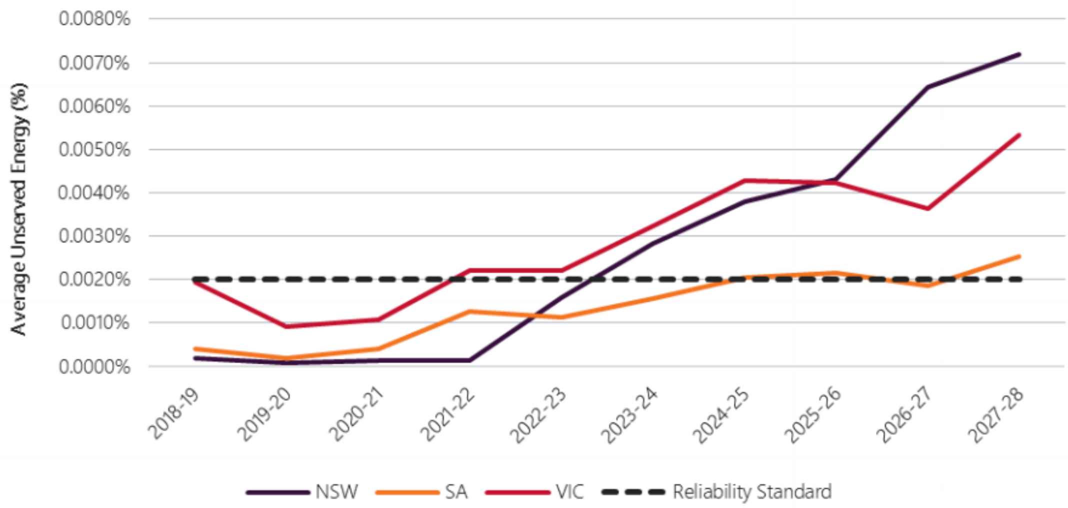
Source: AEMC analysis and estimates based on publicly available information from AEMO's incident reports and the AER's RIN economic benchmarking spreadsheets.

Note: With regard to outages on the distribution network in 2017/18, a number of distribution network service providers (DNSPs) have reported unsupplied energy data on a calendar year rather than financial year basis via the RINs. For these DNSPs, the data for the 2017 calendar year was treated as 2017/18 financial year data. The DNSPs reporting unsupplied energy data on a calendar year basis are: ActewAGL, Endeavour Energy, Energex, Ergon, SA Power Networks and TasNetworks.

Projections of unserved energy

156 The Panel has considered the AEMO's projections of unserved energy (USE) at a wholesale level. The figure below shows forecast USE in the next ten years in Victoria, New South Wales, and South Australia. The Panel notes this forecast assumes no generation projects being developed beyond those currently committed.

Figure 17: Forecast USE outcomes



Source: AEMO, *2018 Electricity statement of opportunities,* August 2018.

157 Key insights highlighted by AEMO in the *2018 ESOO* include:

- Without RERT, there was a heightened risk of USE exceeding the reliability standard in Victoria during 2018/19 summer, with projected USE only marginally below the reliability standard. The key drivers of the heightened USE risk assessment in the short term was:
  - An increase in the projected likelihood of unplanned and forced generation outages
  - An increase in expected peak demand across Victoria and South Australia
  - A reduction in the export capacity of Basslink.[117]
- After 2018/19 summer, the risk of USE in Victoria is forecast to reduce in the short term, due to a slight reduction in forecast peak demand and the introduction of additional renewable generation.
- As the forecast peak demand begins to grow, and Torrens Island A and Liddell power stations retire in 2019/21 and 2022 respectively, USE is projected to begin rising. Forecast USE is above the reliability standard in Victoria by 2021/22, in New South Wales by 2023/24, and in South Australia by 2024/25.
- There is no USE forecast in either Tasmania or Queensland over the ten-year modelling horizon.

158 According to AEMO, the following is required to address the reliability gap:[118]

117 *2018 ESOO* modelling assumed the Basslink interconnector operation with a 478 MW limit in both directions based on forward-looking transfer capabilities supplied in the MT PASA. This represents a reduction in transfer capacity from Tasmania to Victoria of 116 MW compared to the *2017 ESOO.*

118 AEMO, *2018 Electricity statement of opportunities,* August 2018, pp. 54-55.

- After the closure of Liddell Power Station, the equivalent of 350 MW of dispatchable capacity[119] (beyond that already operating or committed) would be required by 2023/24 across Victoria, New South Wales, and South Australia, rising to 1,160 MW by 2027/28.
- Transmission augmentations and new lines would reduce the need for more dispatchable capacity by alleviating transmission congestion, leveraging resource diversity, and maximising the value of the existing generation fleet.

Interventions

159 The reliability framework establishes that, if AEMO projects that the market is likely to not meet the reliability standard, and the market has not responded to AEMO's requests for additional capacity, then, to meet the reliability standard and so deliver an acceptable level of reliability, AEMO may make a decision to intervene in the wholesale market.

160 Intervention mechanisms are 'last resort' powers. Under the NER, there are three key intervention mechanisms related to reliability: the RERT, directions and instructions.[120]

161 The RERT was activated twice in 2017/18 to maintain the power system in a reliable operating state. The RERT was activated for the first time in the history of the NEM on 30 November 2017, following a forecast LOR2 in Victoria. AEMO also entered into reserve contracts in January 2018 and activated the RERT in Victoria and South Australia. AEMO has noted that both short- and long-notice RERT providers were used.

162 The volume of energy dispatched by AEMO via the RERT during the two activations was 107 MWh for the 30 November 2017 activation and 390 MWh for the 19 January 2018 activation.

163 According to AEMO, total RERT costs for 2017/18 were $52 million.[121] This includes: availability payments of $27.03 million, pre-activation costs of $21.56 million, activation costs of $3.23 million and other costs of $0.17 million. The total cost has been recovered on a regional basis as follows: Victoria - $50.7 million, South Australia - $1.2 million.

164 During 2017/18 no directions or instructions to market participants were issued to maintain the system in a reliable operating state.

Lack of reserve notices

165 Market reserve levels refer to the amount of spare capacity available given amounts of generation, forecast demand and demand response, and scheduled market network service provider capability at any point in time.[122] In simple terms, market reserves can be thought of as the "buffer" that is made available by the market as part of the usual operation of the power system.

166 In the short term (from real time to seven days ahead of real time), AEMO informs the market of 'lack of reserve' (LOR) conditions to encourage a response from market

119 This includes flexible thermal generation, demand response and renewable generation with storage.

120 An instruction differs from a direction in the types of market participants AEMO can require taking action, and the nature of the action taken. AEMO issues directions to generators to increase (or decrease) their output or a scheduled load to decrease (or increase) consumption. Instructions generally involve AEMO requiring a network service provider or a large energy user to shed load.

121 AEMO, *RERT 2017-18 cost update*, 2018, p. 1.

122 Reserves are defined in Chapter 10 of the rules.

participants to provide more capacity into the market: generators may offer in more supply, or consumers can reduce their demand. Both responses have the effect of improving market reserve margins, and maintaining power system reliability.

167 Prior to February 2018, AEMO calculated the LOR levels as follows:

- Lack of reserve level 1 (LOR1): when the consecutive occurrence of both the largest and the second largest relevant credible contingency events would result in load shedding occuring as a result of a shortfall of available capacity reserves.
- Lack of reserve level 2 (LOR2): when the occurrence of the largest relevant credible contingency event would result in load shedding as a result of a shortfall of available capacity reserves.
- Lack of reserve level 3 (LOR3): when load shedding is occurring or about to occur as a result of a shortfall of available capacity reserves.

  Until December 2017, when the AEMC made *Declaration of Lack of Reserve conditions* rule, LOR1 and LOR2 levels were determined solely on the basis of the largest credible contingencies in a region, as described above.[123] This approach had limited ability to take into account risks of unexpected reductions in reserves due to factors that exist now in the changing power system, such as a sudden decrease in demand or a decrease in scheduled or intermittent generation.

  After the rule change was made, a new process developed by AEMO introduced a probabilistic element into the determination of LOR levels, which allows for the impact of estimated reserve forecasting uncertainty in the prevailing conditions, known as the forecasting uncertainty measure (FUM), to be accounted for when calculating the LOR levels. These estimates are made on the basis of modelling past reserve forecasting performance for demand, output of intermittent generation and availability of scheduled generation.

  As a result, LOR levels are now calculated as follows:[124]

  - LOR1 is still at least the size of the two largest credible contingency events as a minimum, except when the FUM is larger than these, at which point LOR1 is set by the FUM.
  - LOR2 is still at least the size of the largest credible contingency event, except when the FUM is larger than this, at which point LOR2 is set by the FUM.
  - LOR3 is unchanged.

168 Given that the new LOR framework was introduced in February 2018, 2017/18 LOR notices include notices declared under the old framework as well as the new framework.

169 The figure below shows the number of LOR notices issued in the NEM since 2008/09. In 2017/18, there were 21 LOR notices issued, which is a slight decrease from 22 notices issued in 2016/17. Further, in 2017/18 there were no LOR3 notices issued.[125] However, the number

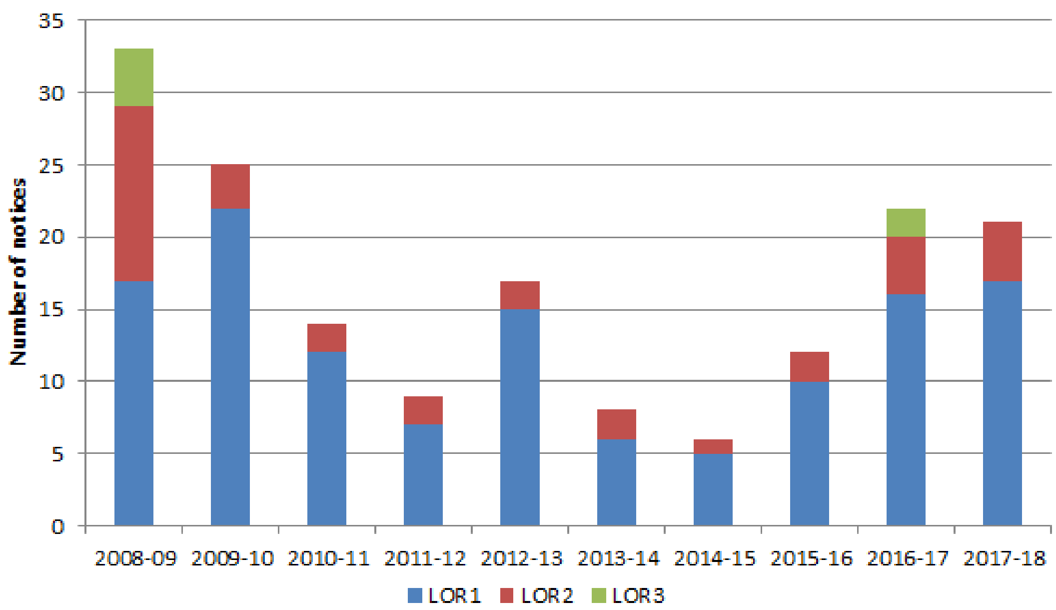
123 For more information see: https://www.aemc.gov.au/rule-changes/declaration-of-lack-of-reserve-conditions

124 The three conditions are defined in AEMO's *Reserve Level Declaration Guidelines,* which were introduced in January 2018.

125 In 2016/17, LOR3 notices were issued on 8 February 2017 in South Australia and 10 February 2017 in New South Wales.

of LOR notices issued in the past two years has been higher than previous periods, which may indicate that the supply-demand balance has become tighter.

Figure 18: LOR notices issued in the NEM



Source: AEMO.

Supply side variability and reliability

170 Changes in the generation mix may have a number of implications for the reliability of the NEM. In particular, there is a number of reliability implications associated with the potential coincident unplanned or planned outages of thermal generation.[126] The variability of supply from intermittent renewable generation may also impact on both the reliability and security of the power system.

Thermal generation availability

171 Many thermal coal generating systems in the NEM have overall capacities well over 1,000 MW, with individual units within those generating system being as large as 744 MW.[127] The unexpected trip of just a few of these large units can immediately place stress on the system, especially at times of high demand.

172 Furthermore, a number of the NEM's thermal generators have been in service for over 40 years. The age of these units may make them more prone to forced outages (due to plant breakdown), or to increase the frequency and length of planned outages (due to necessary maintenance and repair works). This will become particularly prevalent amongst those

126 An outage is considered 'unplanned' if the outage cannot reasonably be delayed beyond 48 hours.

127 The capacity of the Kogan Creek Power Station is 744 MW.

generators that are past their technical operating lifespan.

173 A complicating factor is that any increases in the number of periods of tight supply-demand balance in the market may result in limited flexibility as to when planned outages for maintenance of these older units can occur, while time to recall a generator outage can be long. Furthermore, there are emerging challenges in some states where generation maintenance needs to be rescheduled to maintain system strength during periods of low demand. This is typically during shoulder months, when maintenance is traditionally scheduled in preparation for higher demands in winter and summer.[128]

174 Given the limited window in which maintenance can be scheduled, there are increasing operational risks associated with maintaining reliability and system security when maintenance does proceed. Equally, however, if preventative maintenance cannot occur in a timely manner due to power system security concerns, there is higher risk of plant failure and impacts on overall reliability during high demand periods.[129]

175 In its *2018 Electricity Statement of Opportunities* (ESOO), AEMO found that because the existing thermal generation fleet is ageing, it appears likely that the aggregate reliability of thermal plant may be reducing. This is most evident over the past three years.[130] This is evidenced through the change in generator outage data that AEMO collected from participants and then used in the *2018 ESOO*.

176 The Panel notes that the forced full outage rates[131] increased in 2018 projections for all generator aggregation, with the most significant increase for black coal generators in New South Wales before 2022.[132]

Table 2: Forced outage assumptions in 2018 ESOO

GENERATOR AGGREGATION	FULL OUTAGE RATE – *2018 ESOO*	FULL OUTAGE RATE – *2017 ESOO*
Brown coal	5.34%	4.10%
Black coal QLD	2.42%	2.05%
Black coal NSW – until 2022	6.56%	2.05%
Black coal NSW – after 2022	3.88%	2.05%
CCGT	1.33%	0.62%
OCGT	3.56%	0.66%

128 AEMO, *Electricity statement of opportunities*, August 2018, p. 63.

129 Ibid.

130 Market participants provide AEMO, via an annual survey process, details of the timing and size of historical unplanned generator outages. This data was used by AEMO to calculate the probability of forced outages, which were then applied randomly to each unit in the ESOO modelling. To protect the confidentiality of this data, AEMO calculated outage parameters for a number of technology aggregations. AEMO, *Electricity statement of opportunities*, August 2018, p. 48.

131 Forced outage rates depict the probability of different types of generators experiencing an unplanned full outage.

132 In the *2018 ESOO*, a number of methodological changes have been made compared to the *2017 ESOO* with regard to outage modelling. For a number of technology aggregations, there has been a clear deterioration in reliability over the period where data is available. To reflect more realistic expectations of generator performance, among other things, AEMO has used only the most recent three years of outage data for brown coal, black coal, and gas-fired steam turbines. The Panel acknowledges that this change in methodology may contribute to the increased outage rates.

GENERATOR AGGREGATION	FULL OUTAGE RATE – *2018 ESOO*	FULL OUTAGE RATE – *2017 ESOO*
Steam Turbine	4.58%	1.73%
Hydro	1.58%	0.82%

Source: AEMO, *2018 Electricity Statement of Opportunities*, August 2018.

177 In regard to summer 2018/19, the Panel notes that total brown coal-fired generation during Q4 2018 was 8,227 GWh, representing the lowest quarterly average since market inception. This was a function of extended outages at Yallourn and Loy Yang A power stations. Black coal-fired generation in New South Wales was three per cent higher than in Q3 2018 despite lower electricity demand, driven by higher wholesale electricity prices and increased availability. Output from Queensland's black coal-fired generation was consistent with Q3 2018 results, with higher wholesale prices balancing the impact of lower availability. There was also a relatively high number of sudden generator trips when compared to recent quarters, particularly in Queensland and New South Wales. At this stage, however, Q4 2018 results are not indicative of a longer-term trend, with the number of sudden unit trips in 2018 consistent with results in recent years.[133]

Renewable generation availability

178 Due to the variable nature of wind and solar, there is potential for material variations in energy availability from these generators, which may have reliability implications for the system. Further, there is also always a possibility of unusual weather conditions that may impact energy generation, as was the case in June 2017 when the lowest levels of wind were observed over the last five years. Although these kinds of changes would not be expected to occur on a regular basis, they can pose challenges to the secure and reliable operation of the power system, particularly if they occur at times of very high demand.

179 The accuracy of forecasting is therefore a key factor in the effective integration of variable renewable generation into the NEM.[134] On this basis, forecasting systems will be an increasingly important tool for promoting efficiencies in NEM dispatch, pricing, system reliability and security, as renewable generation continues to make up a larger share of the generation mix.

180 AEMC analysis of historic forecasting accuracy also shows that the level of deviation between actuals and forecasts has generally remained steady over time. However, accurate forecasting has become more complex due to greater volumes of variable renewable energy generation entering the NEM.[135] Further, forecasting of variable renewable generation beyond seven-day time horizon is hard and, as could be expected, there is a significant degree of difference that can occur between forecast and actual variable renewable generation output. The Panel's assessment of AEMO's forecasting accuracy is outlined in appendix E.

133 AEMO, *Quarterly energy dynamics - Q4 2018*, February 2019, p. 11.
134 The Panel acknowledges that demand forecasting accuracy will also play a key role in this process.
135 AEMC, *Reliability frameworks review,* final report, July 2018, p. 31.

181 The Panel notes that AEMO and ARENA have started the *Market Participant 5-Minute forecast* project to enable self-forecasting by utility-scale wind and solar projects, on a voluntary basis. As a part of this project, wind and solar farms will be able to submit their own forecasts to AEMO. This will allow local measurements to be combined with AEMO's modelling to improve the overall accuracy. Self-forecasting for a longer horizon, such as a few hours or even a day ahead, could provide a tangible reliability benefit by better informing AEMO and the market of the likely future output of wind and solar generators. In doing so, it would make wind and solar generators operate more similarly to scheduled generators who offer into the market.[136]

Safety

182 In accordance with the terms of reference issued by the AEMC, for the purposes of the safety assessment the Panel has considered the maintenance of power system security within the relevant standards and technical limits. In the technical safety sense, safety of the national electricity system can be understood to mean that the transmission and distribution systems, and the generation and other facilities connected to them are safe from damage.

183 Following a review of AEMO's power system incident reports and consultation with AEMO, the Panel is not aware of any incidents where AEMO's management of power system security has resulted in a safety issue with respect to maintaining the system within relevant standards and technical limits.

Conclusions

184 There were a number of significant changes in 2017/18, which reflected various ongoing trends in the NEM.

185 One such change was the significant new entry of variable, asynchrounous generation. In 2017/18, 1.2 GW of new generation was commissioned and 5.5 GW was committed. This commissioned and committed generation was mostly comprised of large scale solar and wind projects. On the consumer side of the meter, there has also been a continued uptake of distributed energy resources, with continued strong growth of residential rooftop PV.

186 These changes have a number of implications for the ongoing security and reliability of the NEM.

187 In addition to providing energy production and dispatchable power, thermal generators have also traditionally been relied on to provide essential grid security services, such as inertia, system strength, and frequency control. Existing frameworks, as they are currently applied, may be inadequate in addressing the future needs of the power system, as they do not place an explicit value on the provision of some of these services and do not coordinate with the provision of other system services, such as system strength. This leads to the increasing number of instances when AEMO intervenes the market to maintain the system in a secure state. The forecast retirement of conventional generation fleet and challenges associated with it demonstrate the ongoing importance of maintaining system security in a changing

136 For more information, see: https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Market-Participant-5-Minute-Self-Forecast and https://arena.gov.au/funding/programs/advancing-renewables-program/short-term-forecasting/

environment.

188 While the NEM has had very little unserved energy over the past ten years, AEMO projections suggest that, in the absence of sufficient market response, there may not be enough dispatchable generation to meet demand in the medium term. This projected shortfall highlights the need for efficient supply side and/or demand side investment so that consumer demand for energy continues to be met.

189 Finally, the Panel notes the rapid growth in uptake of distributed energy resources, such as residential rooftop solar PV and behind the meter battery storage systems. The increased penetration of these technologies has the potential to both create new challenges for the power system, as well as new opportunities to deliver services to support security and reliability.

190 In the context of all of these challenges, the Panel acknowledges the significant body of work underway that is considering how to maintain the ongoing security and reliability of the NEM.

191 The Panel intends to monitor and review how these processes progress over the coming year, with a view to recommending whether any further work remains to be done, or key issues that need to be addressed, in the 2019 AMPR.

192 The body and appendices of this report provide more detail on the issues covered in this concise report.

CONTENTS

APPENDICES

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FIGURES

1 INTRODUCTION

This report has been prepared as part of the Reliability Panel's (Panel) *Annual market performance review* (AMPR) of the National Electricity Market (NEM). It covers the 2017/18 financial year. The review is a requirement of the National Electricity Rules (rules or NER).

1.1 Background

The functions of the Panel are set out in clause 8.8.1 of the rules. Among other things, the Panel is required to:

- monitor, review and report on the performance of the market in terms of reliability of the power system[137]
- report to the Australian Energy Market Commission (AEMC) and participating jurisdictions on overall power system reliability matters, power system security and reliability standards and the Australian Energy Market Operator's (AEMO) power to issue directions in connection with maintaining or re-establishing the power system in a reliable operating state.

Consistent with these functions, clause 8.8.3(b) of the rules requires the Panel to conduct a review of the performance of certain aspects of the market, at least once every financial year and at other such times as the AEMC may request. The Panel must conclude each annual review under this clause by the end of the financial year following the financial year to which the review relates. The Panel must conduct its annual review in terms of:

- reliability of the power system
- the power system security[138] and reliability standards
- the system restart standard
- the guidelines referred to in clause 8.8.1(a)(3) of the rules[139]
- the policies and guidelines referred to in clause 8.8.1(a)(4) of the rules[140]
- the guidelines referred to in clause 8.8.1(a)(9) of the rules.[141]

1.2 Purpose of the report

The purpose of this report is to set out the Panel's findings for its annual market performance review for 2017/18. In conducting this review, the Panel has only considered publicly

137 In performing this function, clause 8.8.1(b) of the rules prohibits the Panel from monitoring, reviewing or reporting on the performance of the market in terms of reliability of distribution networks. However, the Panel may collate, consider and report information in relation to the reliability of distribution networks as measured against the relevant standards of each participating jurisdiction, in so far as the reliability of those networks impacts on overall power system reliability.

138 Standards and guidelines relevant for security are discussed in more detail in section 2.4.

139 The guidelines referred to in clause 8.8.1(a)(3) of the rules govern how AEMO exercises its power to issue directions in connection with maintaining or re-establishing the power system in a reliable operating state.

140 The policies and guidelines referred to in clause 8.8.1(a)(4) of the rules govern how AEMO exercises its power to enter into contracts for the provision of reserves.

141 The guidelines referred to in clause 8.8.1(a)(9) of the rules identify, or provide for the identification of, operating incidents and other incidents that are of significance for the purposes of the definition of 'reviewable operating incident' in clause 4.8.15 of the rules.

available information as well as information obtained directly from relevant stakeholders and market participants.[142]

The Panel's findings include observations and commentary on the reliability, security and safety performance of the power system. The review also provides an opportunity for the Panel to consolidate key information related to the performance of the power system in a single publication for the purpose of informing stakeholders. Among other things, this may assist governments, policy-makers and market institutions to monitor the performance of the power system, and to identify the likely need for improvements to the various measures available for delivering reliability, security and safety.

1.3 Scope of the review

The Panel is undertaking this review in accordance with the requirements in the rules and the terms of reference issued by the AEMC.[143]

The AEMC requests that the Panel review the performance of the market in terms of reliability, security and safety of the power system in 2017/18. The Panel has had regard to the following matters when conducting its review:

- **Overall power system performance:** A comprehensive overview of the performance of the power system is provided. The Panel has considered:
    - Performance in terms of reliability and security from the perspective of the generation bulk transmission sectors and impacts on end-use customers where relevant information is available.
    - Significant power system incidents (including but not necessarily limited to 'reviewable operating incidents') that have occurred in the financial year 2017/18 including the cause of the incident (a reliability or security event), the impact of the incident (on reliability or security, and in terms of the costs to consumers) and the sector of origin (generation, transmission or distribution).[144]
    - In particular, the Panel has considered incidents, when the power system was not in a secure state for more than 30 minutes. In 2017/18, there was one such instance.
    - Another major incident, Queensland and South Australia network separation on 25 August 2018, did not occur within the reporting period for this annual market performance review. Accordingly, a short summary of this event is provided in chapter 5 of this AMPR. A more detailed consideration of Queensland and South Australia

142 The data and information gathered has been provided by a number of organisations including AEMO, network service providers, the Australian Energy Regulator (AER) and jurisdictional government departments and regulators. This data and information provided by other parties has not been verified for accuracy or completeness by the Panel. It has been assumed that those organisations have undertaken their own quality assurance processes to validate the data and information provided.

143 The terms of reference for this review are available on the AEMC Reliability Panel website.

144 A reviewable operating incident is a term defined in clause 4.8.15 of the NER. It refers to, among other things, a non-credible contingency event or multiple contingency events on the transmission system; or a black system condition; or an event where the frequency of the power system is outside limits specified in the power system security standards; or an event where the power system is not in a secure operating state for more than 30 minutes; or an event where AEMO issues an instruction under clause 4.8.9 of the rules for load shedding - an incident where AEMO has been responsible for the disconnection of facilities of a Registered Participant under the circumstances described in clause 5.9.5 of the rules; or any other operating incident identified, in accordance with guidelines determined by the Reliability Panel under rule 8.8, to be of significance to the operation of the power system or a significant deviation from normal operating conditions.

network separation will be provided in AMPR 2019, which will cover the financial year 2018/19.

- **Reliability performance of the power system:** The Panel has reviewed reliability performance of generation and bulk transmission (i.e. interconnection). In doing so, it has considered:
  - actual levels of unserved energy in 2017/18
  - actual and forecast supply and demand conditions (including an assessment of lack of reserve notices) in order to form a view on whether any underlying changes to reliability performance have occurred, or are expected to occur
  - AEMO's use of the reliability safety net mechanisms in 2017/18, including incidents of, and reasons for, the use of directions and instructions, and the Reliability and Emergency Reserve Trader (RERT) mechanism.
- **Security performance of the power system:** The Panel has reviewed performance of the power system against the relevant technical standards. In particular, the Panel has had regard to: frequency operating standards, voltage limits, interconnector secure limits and system stability.
- **Safety performance of the power system:** The Panel does not have an obligation under the National Electricity Law or Rules to review, report and monitor the safety of the national electricity system.[145] However, in addition to its functions under the Rules the Panel has the function of advising in relation to the safety, security and reliability of the national electricity system at the request of the AEMC.[146] The terms of reference for the *2018 Annual market performance review*, as they relate to safety, were considered by the Panel as a request for advice.[147] In accordance with the terms of reference issued by the AEMC, for the purposes of the safety assessment the Panel has considered the maintenance of power system security within the relevant standards and technical limits.[148]

1.4 Review process

The Panel is carrying out this review in accordance with the process set out in the rules and reflected in the AEMC's terms of reference. The following table outlines the planned timetable for delivery of the Panel's final report to the AEMC.

145 Instead, the functions of the Reliability Panel under clause 8.8.1 of the Rules provide that the functions of the Panel is to, among other things, monitor, review and report on the performance of the market in terms of reliability of the power system, report to the AEMC and jurisdictions on overall power system reliability matters and undertake a number of functions relating to the security of the power system. The reliability and security focus of the Panel under the Rules is reflected in the scope of the annual market performance review that the Panel is required to undertake under clause 8.8.3(b) of the Rules.

146 If the AEMC requests such advice, the Panel is required to provide it (section 38(4) of the NEL).

147 Under section 38(2)(b) of the NEL.

148 More information on safety concept is provided in chapter 2. Safety of jurisdictional power systems is primarily administered by individual jurisdictions. Additional information on individual jurisdictional considerations of safety is provided in appendix I.

Table 1.1: Review process

MILESTONE	DATE
Project initiated	6 September 2018
Comments on the approach were due	18 October 2018
Publication of final report	04 April 2019

The Panel did not receive any comments on the approach and issues to be considered in this review.

1.5 Structure of this report

This report has been structured in order to assist readers seeking different levels of information and detail. The concise report provides a high level overview of the Panel's key findings, while this main body of the report provides a greater level of detail on key market trends and issues. Further and more specific detail, including tables of results and other technical information, is provided in relevant appendices.

The remainder of the document is set out as follows:

- **Chapter 2 - Key concepts and relevant standards and guidelines:** an explanation of key areas addressed by AMPR, including an overview of the standards and guidelines published by the Panel and the operational guidelines that AEMO uses to manage the power system.
- **Chapter 3 - Market trends:** an overview of trends in the NEM for 2017/18.
- **Chapter 4 - Reliability review:** an overview of the reliability performance of the NEM in 2017/18, historical performance, major system events, assessment of emerging trends and work underway focussing on reliability.
- **Chapter 5 - Security review:** an overview of security related issues and major events that occurred during 2017/18, as well as work underway addressing these issues.
- **Chapter 6 - Safety review:** a high level summary of what power system safety is, and the performance of the power system from a safety perspective.
- **Appendices:** detailed background information on various aspects of NEM power system management and performance.
  - Appendix A – Generation capacity changes
  - Appendix B – Network performance
  - Appendix C – The contract market
  - Appendix D – Reliability assessment
  - Appendix E – Forecasts
  - Appendix F – Weather summary
  - Appendix G – Security performance
  - Appendix H – Reviewable operating incidents during 2017/18
  - Appendix I – Safety framework

- Appendix J – Pricing review
- Appendix K – Market price cap and cumulative price threshold
- Appendix L – Environmental and renewable energy policies
- Appendix M – AEMC's security and reliability work program
- Appendix N – Glossary

2 KEY CONCEPTS AND RELEVANT STANDARDS AND GUIDELINES

This review examines the performance of the NEM in terms of reliability, safety and security. These concepts are discussed below, with an explanation of the relevant standards and guidelines.

In this report the Panel considers reliability and security separately and has structured the report accordingly. This reflects the differences between security and reliability. A secure system is one that is able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. A reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence.

The two concepts are closely related operationally and it is not always simple to separate them. A reliable power system will also be a secure power system. However, the converse is not necessarily true; a power system can be secure even when it is not reliable. One of the ways in which AEMO can do this is to undertake involuntary load shedding, potentially compromising reliability, in order to return the power system to a secure operating state.

Under current market and regulatory frameworks, separating these two aspects of the supply of power is important, as reliability and security are managed through the use of different tools and regulatory frameworks.

The Panel acknowledges that for consumers, the final result of either a reliability event or a security event may be indistinguishable - the lights may go out either way.

However, the Panel also considers it important to clearly describe and identify how these two aspects of power supply work, and the extent to which each is responsible for final interruptions to consumers. This is helpful in that it allows for identification of where further actions may be needed, in order to improve outcomes for consumers in the future.

2.1 Reliability

The reliability of the power system is about having sufficient generation, demand side response, and interconnector capacity in the system to generate and transport electricity to meet consumer demand.[149] A reliable power system requires the following:

- efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of capacity to meet demand, plus a sufficient level of reserves
- a reliable transmission network
- a reliable distribution network, and

149 Reliability is an economic construct to the extent that it must be cost-effective for generators and networks to have enough capacity to meet demand; whereas security is a technical concept as discussed in section 2.2.

- the system being in a secure operating state, that is, one where the power system is in, or will return to, the NER requirement of a satisfactory operating state within 30 minutes.[150]

Figure 2.1 provides the summary of the existing reliability framework, including the reliability standard, the reliability settings and AEMO's intervention mechanisms. The regulatory framework for reliability in the NEM is primarily market based.

Figure 2.1: Reliability framework

Source: AEMC, *Reliability frameworks review*, July 2018, Sydney.

2.1.1 Market incentives

The buying and selling of electricity through a wholesale spot market, as well as associated financial products such as exchange traded derivatives and bilateral contracting, is the main mechanism through which reliability is delivered in the NEM. Market participants make investment and operational decisions based on these market signals. Prices in the spot and contract markets provide signals for adequate generation and demand-side resources to be built and dispatched, as well as information about the balance of supply and demand across different places and times.

The core objective of the existing reliability framework in the NEM is to deliver efficient reliability outcomes through market mechanisms to the largest extent possible. As the expected supply/demand balance tightens, spot and contract prices will rise - within the price envelope - which will inform operational decisions and provide an incentive for entry and increased production, addressing any potential reliability problems as or before they arise.

150 The "satisfactory operating state" is a defined term under the NER, which is set out in clause 4.2.2.

2.1.2 Market settings

Reliability standard

Reliability is measured in terms of unserved energy, which refers to the amount of energy that is required (or demanded) by consumers but which is not supplied due to a shortage of generation or interconnection capacity.

The current reliability standard is focussed on the wholesale market and is expressed in terms of the maximum expected unserved energy, or the maximum amount of electricity expected to be at risk of not being supplied to consumers in a region of the NEM, per financial year.[151]

Crucially, this is not set at zero per cent. The current reliability standard is 0.002 per cent expected unserved energy. In simple terms, the reliability standard requires there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of forecast annual demand for electricity is expected to be supplied. When the reliability standard is set, it involves a trade-off between the prices paid for electricity and the cost of not having energy when it is needed - increasing levels of reliability involves increased costs.

A key role of the reliability standard is to guide various decisions made by AEMO in its role as the system operator, with these decisions then provided as information to the market and so in turn informing market participant decisions. It is AEMO's responsibility to incorporate the reliability standard within its day-to-day operation of the market, and to inform the market of any projection that the reliability standard will not be met. If market participants do not respond to an expectation from AEMO that the reliability standard will not be met, then AEMO may intervene through either using the RERT mechanism or instructions/directions issued under clause 4.8.9 of the rules.

In relation to the Panel's review, reliability performance is considered in terms of actual observed levels of unserved energy at the wholesale level for the most recent financial year. The reliability of the NEM is reviewed by AEMO each year to examine any incidents that have resulted in unserved energy at the wholesale level.

Reliability settings

The reliability settings are closely linked to, and derived directly from, the reliability standard. Their purposes are to:

- Maintain the overall integrity of the market, by protecting market participants and consumers from excessively high prices and thereby preventing systemic financial collapse within the energy sector.[152]
- Allow for sufficient investment to provide electricity to the agreed reliability standard.

151 In this context, the wholesale market refers to the supply of energy from generation (or demand side response), and transported by inter-regional transmission infrastructure. There are other parts of the supply chain, outside the wholesale market, that also play a role in delivering energy to consumers, including intra-regional transmission and distribution networks.

152 Large consumers who buy wholesale are directly protected by the settings. The market settings indirectly protect consumers assuming that retailers will pass through the impact of the price caps in a competitive market.

These form an envelope for spot prices:[153]

- Market price cap - The maximum price that a generator may bid during a dispatch interval is currently $14,500/MWh.[154]
- Market floor price - The minimum price that a generator may bid during a dispatch interval is -$1,000/MWh.
- Cumulative price threshold - This limits market participants' financial exposure to prolonged high prices, by capping the market price (currently at $212,800/MWh) that can occur over seven consecutive days.
- Administered price cap - This $300/MWh cap applies when an administered pricing period is declared by AEMO whenever the sum of the spot price in the previous 336 consecutive trading intervals (that is, seven days) exceeds the cumulative price threshold.[155]

Supplementary information

AEMO is required by the NER to publish various materials which provide information to market participants and any other interested parties on matters pertaining to the reliability standard. This information is an important part of the existing reliability framework that helps guide and inform market participants' expectations of the future, enabling more efficient investment and operational decisions.

Intervention mechanisms

AEMO's 'last resort' intervention powers enable it to deal with actual or potential shortages of varying degrees of severity. In each instance, the power in question is designed to be implemented in a way that results in the smallest disruption possible to the ongoing operation of the market. These intervention mechanisms include:[156]

- The RERT allows AEMO to contract for additional, emergency reserves such as generation or demand response that are not otherwise available in the market. They are additional reserves because they are in addition to the "buffer" that is made available by the market as part of the usual operation of the power system.
- In addition, if there is a risk to the secure or reliable operation of the power system, AEMO can use directions or instructions under NER clause 4.8.9 to:
  - direct a generator to increase its output or to connect to the power system and synchronise, if this is possible and can be done safely
  - instruct a large energy user, such as an aluminium smelter, to temporarily disconnect its load or reduce demand.

If there continues to be a shortfall in supply, even after these measures have been implemented, AEMO may require involuntary load shedding as a last resort to avoid the risk of a wider system blackout, or damage to generation or network assets. It does this by

153 Market performance in terms of market price cap and cumulative price threshold is discussed in more detail in appendix K.
154 This is indexed annually by the consumer price index (CPI) by the AEMC.
155 This is indexed annually by CPI by the AEMC.
156 AEMO's intervention mechanisms are discussed in more detail in section 4.

instructing a transmission network service provider to arrange for the interruption of consumer load under clause 4.8.9 of the NER. The order and location of the interruptions are based on a schedule set by each jurisdiction. Essential services such as hospitals and other sensitive consumers (such as businesses in the CBD or critical industries) are typically prioritised to have supply maintained.

These intervention mechanisms provide an important ultimate safety net when there is insufficient generation capacity to maintain adequate reserves above demand, to minimise the adverse impacts on customers of involuntary load shedding. Although AEMO would be expected to do all in its power to avoid load shedding using the above intervention mechanisms, there will be times when involuntary load shedding will be unavoidable because the level of investment and operational decisions are being driven by a reliability standard that is non-zero.

The rules do not give specific direction to AEMO on how to implement the reliability standard, but they do require AEMO to perform the following functions in accordance with the reliability standard implementation guidelines:[157]

- In the medium-term, through the medium-term projected assessment of system adequacy (PASA), identify and quantify any projected failure to meet the reliability standard.[158]
- In the short term, through the short term PASA identify and quantify any projected failure to meet the reliability standard.
- To keep the system in a ''reliable operating state" in real time, assess whether the power system meets, and is projected to meet, the reliability standard.[159]

In addition to monitoring the system using the information processes mentioned above, AEMO may declare:

- a low reserve condition when it considers that the balance of generation capacity and demand for the period being assessed does not meet the reliability standard as assessed in accordance with the reliability standard implementation guidelines; or
- a lack of reserve condition to advise market participants whenever it determines that the probability of involuntary load shedding (other than the reduction or disconnection of interruptible load) is, or is forecast to be, more than remote.

To assess the reliability performance of the NEM, the 'bulk transmission' capacity of the NEM is taken to equate to interconnector capability.[160] Consequently, only constraints in the

157 The reliability standard implementation guidelines are available on AEMO's website at: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Reliability-Standard-Implementation-Guidelines. The rules also oblige AEMO to publish the *Electricity statement of opportunities* (ESOO) by 31 August each year. The ESOO is an information tool providing information that can help stakeholders plan their operations over a ten-year outlook period, including information about the future supply demand balance. The intention of the ESOO is not a definitive guide to assess how much reserves should be procured, nor to inform governments about what actual outcomes in the market will be. Instead, the purpose is solely as a market information tool: signalling to the market ahead of time when there might be potential shortfalls to elicit a response from market participants.

158 PASA is a programme of information collection, analysis and disclosure of power system security and reliability of supply prospects.

159 Defined in clause 4.2.7 of the rules.

160 The reason for this is that the reliability standard is measured on a regional basis, and the standard is met when sufficient generation capacity is available in a region. This capacity is calculated as the sum of local generation available within the region itself and of interstate generation available via an interconnector.

transmission network that affect interconnector capability are considered when assessing the availability of reserves in a region.[161]

Measurement of the reliability performance of the NEM does not take into account interruptions to consumer supply that are caused by outages of local transmission or distribution elements that do not significantly impact the ability to transfer power into the region. Interruption to supply caused by these kinds of events do not count towards measurements of unserved energy.

However, the performance of distribution and transmission networks do influence the supply outcomes experienced by electricity consumers. Therefore, consistent with the AEMC's terms of reference, the Panel has also included information on the performance of the non-bulk transfer transmission and distribution networks.

Measurement of the reliability performance of the NEM also does not consider any interruptions to supply that are the result of non-credible (or multiple) contingency events.[162] Interruption of consumer load in these circumstances may be due to an automatic controlled load shedding response that is initiated following a sudden change in frequency in order to prevent power system collapse, rather than the result of insufficient generation or bulk transmission capacity being made available. The consequences of these non-credible contingency events are formally classified as power system security issues and are addressed separately in this report.

The reliability standard also does not include any interruptions to supply due to a black system event, such as the event that occurred in South Australia on 28 September 2016. A black system can occur when non-credible contingency events cause a cascading failure of the power system, resulting in large portions of the system collapsing to a state of zero voltage and energy. As such, the interruption to supply is not due to a lack of generation capacity or bulk transfer capability.

2.2 Security

While reliability measures whether there is sufficient capacity to meet demand, security of the power system refers to maintenance of the power system within specific technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Security events are mostly caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits, such as voltage and frequency.

161 In the *Comprehensive reliability review*, the Panel clarified the definition of "bulk transmission". See AEMC Reliability Panel, *Comprehensive Reliability Review*, final report, 2007, pp. 32-33.

162 Contingency events are the basis of the way in which AEMO operates the power system. The rules require AEMO to undertake various actions so that the power system will be in a given frequency condition following different contingency events. A credible contingency event is an event that AEMO considers to be reasonably possible in the surrounding circumstances. For these events, AEMO is required to maintain the frequency within given limits and achieves this through procuring FCAS and constraining generation dispatch. A non-credible contingency event is a contingency event other than a credible contingency event. This includes, but is not limited to, events such as the simultaneous failure of multiple generating units or a double circuit transmission line failure. For these events, AEMO is required to maintain the frequency and achieves this through controlled automatic load shedding.

'Secure' has a particular meaning under the NER. Specifically, clause 4.2.4 of the NER states that the power system is defined to be in a secure operating state if, in AEMO's reasonable opinion, taking into consideration the appropriate power system security principles described in clause 4.2.6 of the NER:

- the power system is in a ''satisfactory operating state", defined under the NER[163]
- the power system will return to a satisfactory operating state following the occurrence of any credible contingency event or protected event in accordance with the power system security standards.

Secure operation depends on the combined effect of controllable plant, ancillary services, and the underlying technical characteristics of the power system plant and equipment.

System security is managed directly by AEMO and network operators in accordance with applicable technical standards. Maintaining the security of the power system is one of AEMO's key functions. Following a contingency event or significant change in power system conditions, AEMO must take all reasonable actions to return the power system to a secure operating state within 30 minutes.[164] AEMO may authorise a person to do any of the things contemplated by section 116 of the NEL if AEMO is satisfied that it is necessary to do so for reasons of public safety or the security of the electricity system.

The practices adopted by AEMO to manage power system security are defined in its operating procedures and guidelines, which have been developed from overarching guidelines defined by the Panel and obligations under the rules. AEMO is required to operate the power system within the frequency operating standards. These standards specify the frequency bands that the power system must be operated within under specific circumstances. The frequency operating standards are developed by the Panel and are published on the AEMC's website.[165]

Operations consistent with those guidelines are intended to maintain system quantities such as voltage and frequency within acceptable performance standards, as well as providing that certain equipment ratings are not exceeded following credible contingencies.

A principal tool used by AEMO to maintain power system security is the constraint equations used in the market dispatch systems. Violations of constraint equations may indicate, among other things, periods where the power system is not in a secure operating state.

The Panel has reviewed power system security performance by considering the following matters:

- whether the power system has been operated consistent with AEMO's published procedures and guidelines
- whether system parameters have been maintained within the range specified in the relevant standards

163 Satisfactory operating state is defined in the clause 4.2.2 of the NER.

164 Clause 4.2.6(b) of the NER.

165 The Frequency operating standard has recently been reviewed by the Panel. For more information see the *Frequency operating standards review* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard

- whether the system was returned by AEMO to a secure operating state as soon as it was practical to do so, and, in any event, within 30 minutes, as clause 4.2.6(b)(1) of the NER requires
- the frequency and extent of any violation of constraint equations
- the frequency and extent of any violations of equipment ratings.

2.3 Safety

The Panel does not have an obligation under the Law or Rules to review, report and monitor the safety of the national electricity system.[166] However, the Panel has the function of advising in relation to the safety, security and reliability of the national electricity system at the request of the AEMC.[167] The terms of reference for the *2018 Annual Market Performance Review*, as they relate to safety, were considered by the Panel as a request for advice.[168] In accordance with the terms of reference issued by the AEMC, for the purposes of the safety assessment the Panel has considered the maintenance of power system security within the relevant standards and technical limits.[169]

While the terms of reference clearly direct the Panel to focus on technical safety, the *safety of the national electricity system* concept is broader. The safety of the national electricity system can be understood to mean that:

- the transmission and distribution systems and the generation and other facilities connected to them are safe from damage (safety in the technical safety sense); or
- the transmission and distribution systems and the generation and other facilities connected to them are not a source of injury and danger (safety in the public safety sense).

The safety of the national electricity system is the focus of Part 8 of the NEL. This part deals with both power system security matters (technical safety) and matters such as load shedding for sensitive loads (which is directed to public safety). This interpretation is reinforced under section 116 of the NEL that states that AEMO may exercise its power of direction under section 116 of the NEL if it considers it necessary to maintain power system security (technical safety) or for reasons of public safety.

It is open to the AEMC to request advice from the Panel on either or both technical safety of the national electricity system (power system security) or public safety issues relating to the national electricity system or specific aspects of those types of safety as it considers appropriate. The terms of reference clearly direct the Panel to focus on technical safety (power system security) rather than public safety.

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166 Instead, the functions of the Reliability Panel under clause 8.8.1 of the Rules provide that the functions of the Panel is to, among other things, monitor, review and report on the performance of the market in terms of reliability of the power system, report to the AEMC and jurisdictions on overall power system reliability matters and undertake a number of functions relating to the security of the power system. The reliability and security focus of the Panel under the Rules is reflected in the scope of the annual market performance review that the Panel is required to undertake under clause 8.8.3(b) of the Rules.

167 If the AEMC requests such advice the Reliability Panel is required to provide it (section 38(4) of the NEL).

168 Under section 38(2)(b) of the NEL.

169 Safety of jurisdictional power systems is primarily administered by individual jurisdictions. Additional information on individual jurisdictional considerations of safety is provided in appendix I.

The Panel notes that while the general safety of the NEM, and associated equipment, power system personnel and the public is an important consideration under the NEL, in general terms, there is no national safety regulator for electricity. Instead, jurisdictions have specific provisions that explicitly refer to safety duties of transmission and distribution systems, as well as other aspects of electricity systems such as metering and batteries.[170]

These arrangements led to each NEM region being subject to different safety requirements as set out in the relevant jurisdictional legislation. Across the states, different authorities are responsible for supporting electrical safety. They also have different obligations, responsibilities and reporting arrangements in place. Authorities responsible for maintaining electrical safety are: Electrical Safety Office in Queensland, Independent Pricing and Regulatory Tribunal of New South Wales (IPART) in New South Wales, Energy Safe Victoria in Victoria, Office of the Technical Regulator in South Australia and Work Safe Tasmania in Tasmania.

2.4 Standards and guidelines relevant for security

The performance of the power system is measured against various standards and guidelines that form the technical standards framework. This framework is designed to maintain the security and integrity of the power system by establishing clearly defined standards for the performance of the system overall. The framework comprises a hierarchy of standards:[171]

- **Power system security standards:** define the performance of the power system, the nature of the electrical network and the quality of power. These also establish the target performance of the overall power system. AEMO's obligations to manage the power system are included in Chapter 4 of the rules and in the frequency operating standards developed by the Panel. The system standards that apply to the operation of transmission networks are set out in Chapter 5 of the rules.
- **Access standards:** specify the quantified performance levels that a plant or equipment (consumer, network or generator) must achieve to allow it to connect to the power system. Access standards define the range within which parties may negotiate with network service providers, in consultation with AEMO, for access to the network. AEMO and the relevant network service providers need to be satisfied that any access granted to the power system will not negatively affect the ability of the network to meet the relevant system standards, negatively impact system security, or impact on other network users. The access standards have recently been reviewed through the AEMC's *Generator technical performance standards* rule change.[172]
- **Plant standards:** set out the technology specific standards that, if met by particular facilities, allow compliance with the access standards. Plant standards can be used for new or emerging technologies where they are not covered by access standards. The

170 See section 2D(1)(a) of the NEL.

171 In South Australia, The Essential Services Commission of South Australia also applies additional technical license conditions for all generators connecting in South Australia.

172 For more information, see the *Generator technical performance standards* project page: http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards

standard allows a class of plant to be connected to the network if that plant meets some specific standard such as an international standard. To date, the Panel has not been approached to consider a plant standard.

The actual performance of all generating plant must also be registered with AEMO, and becomes known as a performance standard.[173] Registered performance standards represent binding obligations on a generator and are part of the connection agreement between the generator and the network service provider.[174] For a generating plant to meet its registered performance standards on an ongoing basis, participants are also required to set up compliance monitoring programs. These programs must be lodged with the AER. It is a breach of the rules if the generating plant does not continue to meet its registered performance standards and compliance program obligations.[175]

173 Generators with capacities smaller than 5 MW are exempt from registering with AEMO. For more information refer to AEMO's generator registration guidelines. In Victoria AEMO is the planner for the Declared Shared Network (transmission network) and undertakes the role of network service provider in negotiating performance standards.

174 This is required under clause 5.3.7(b) of the rules.

175 The Panel developed a template in 2009 to assist generators in designing their compliance programs. This template was most recently updated by the Panel on 18 June 2015.

3 MARKET TRENDS

This chapter examines some key market trends in the generation mix and bulk transfer capability (i.e. interconnectors) in the NEM, including new generation entry and withdrawals, as well as changes in interconnector capability. It examines trends in distributed energy resources as well as forecast trends in energy consumption and demand levels. It also provides some high level information on wholesale market price outcomes.

The trends in generation, bulk transfer, distributed energy resources and demand play a key role in determining the present and future reliability of the NEM, as reliability is determined to be the ability of generation capacity and bulk transfer to meet demand.[176] These trends also have consequential impacts on the security of the NEM such as the reduction in physical inertia[177] inherent in the system and resultant changes to the rate at which frequency may change following a disturbance.[178]

For the period 2017/18, the Panel notes the following key trends and outcomes:

- **Forecast consumption:** The consumption of NEM grid-supplied energy has remained relatively unchanged in 2017/18 and is forecast to remain relatively flat over the next 10 years.[179]
- **Maximum and minimum demand:** Maximum demand levels are forecast to be relatively stable in most regions over the next five years. However, patterns of when maximum demand is likely to occur during the day are expected to change, with maximum demand more likely to occur later in the day, primarily due to growth in installed rooftop PV. Regional minimum demand levels are forecast to decline rapidly (i.e. become smaller) over the next five years, due to the high rooftop PV uptake. Further, for all regions minimum demand is expected to shift from overnight or early morning to midday, within the next two years.[180] New South Wales, Victoria and Queensland are expected to experience a midday minimum as early as 2019.[181]
- **Generation withdrawals:** In 2017/18, no generation capacity was withdrawn from the NEM. However, market participants have announced retirement of over 2,300 MW of synchronous generation within the next 10 years.
- **New generation:** Between 19 May 2017 and 1 July 2018[182], 1,178 MW of new generation was commissioned and 5,538 MW was committed. This commissioned and

176 The reliability implications of these trends are explored in chapter 4.

177 Inertia is a measure of the ability of the system to resist changes in frequency due to sudden changes in supply and demand. It is naturally provided by synchronous generators such as coal, hydro and gas-fired power stations.

178 The security implications of these trends are explored in chapter 5.

179 Consumption refers to electricity used over a period of time and is referred to in terms of energy measured in megawatt hours (MWh). Demand describes electricity usage at a particular point in time and is typically referred to in terms of power or demand measured in megawatts (MW). For more information see: http://www.aemc.com.au.

180 This is excluding South Australia, which has been experiencing day minima since 2012, and Tasmania, which experienced minimum demand at midday in 2017/18.

181 AEMO, *2018 Electricity statement of opportunities*, August 2018.

182 The analysis provided is not strictly aligned with the 2017/18 financial year. This is because data was derived from the AEMO's regional generation information pages that were published as at 19 May 2017, 22 December 2017, 16 March 2018 and 1 July 2018.

committed generation was mostly comprised of large scale solar and wind projects. Almost all of this generation was asynchronous.[183] Residential rooftop PV systems continue to be installed at a very high rate, with 2017/18 being the highest period of growth in the sector since installations were first recorded. In 2017/18, about 1,300 MW of new rooftop PV capacity was installed, bringing the total rooftop PV capacity in the NEM to about 6,500 MW.[184]

- **Bulk transfer:** In 2017/18, some significant changes occurred in the direction of interconnector flows.[185] Notably, Victoria's exports decreased significantly in comparison with the last three years, while South Australia became a net exporter for the first time since 2008/09.[186]
- **Reviewable operating incidents:** There were 24 incidents reviewed by AEMO in 2017/18, which is five fewer than in 2016/17.[187]
- **Wholesale prices:** In 2017/18, wholesale annual volume weighted average prices eased in most states but remained close to record levels. The annual average price in South Australia remained the highest in the NEM. Victoria held the second highest average price, after increasing for the third year in a row. The annual average price in Queensland fell to the lowest in the NEM.[188] Wholesale average prices are expected to decrease in South East Queensland, Victoria, South Australia and Tasmania in the period from 2017/18 to 2020/21, primarily due to new generation and battery storage entering the NEM.[189]

The scale of many of these trends represent a fundamental shift in how the power system is structured and functions. As will be discussed in subsequent sections, these trends are having material impacts for both the reliability and the security of the NEM.

3.1 Demand and consumption forecasts

Energy use can be considered in terms of the total amount of energy consumed over a time period (described here as energy consumption) or in terms of the rate at which energy is used at a single point in time (described here as demand).

Each of these measures are relevant to market outcomes in the NEM. For example, growth in total energy consumption is relevant to how much bulk energy supply is needed in the NEM.

183 Synchronous generators are large spinning units that have turbines that spin at the same speed as the frequency of the power system. This characteristic of these types of generators means that they are electromechanically linked to the power system frequency, and can contribute to specific system qualities such as provision of physical inertia and support of system strength. Asynchronous generators are linked to the power system through power system electronics and do not provide the same kind of inertia (though they may provide synthetic inertia, or fast frequency response services), or support for system strength. One small synchronous unit was commissioned in 2017/18 - Lake Somerset (4.3 MW). Tableland Mill (24 MW) and Barker Inlet Power Station (210 MW) were committed in 2017/18. Synchronous generation typically provides physical inertia and fault currents.

184 AEMO, *2018 Electricity statement of opportunities*, August 2018.

185 Power can flow in both directions across an interconnector. Usually, the direction of this flow reflects the price differential between two regions, flowing from the lower priced region to the higher priced region.

186 AER, *Wholesale statistics*.

187 Reviewable operating incidents are defined in the rules, under clause 4.8.15 of the rules.

188 AER, *Wholesale electricity market performance report*, December 2018.

189 AEMC, *Residential electricity price trends 2018,* December 2018.

Changes in patterns of maximum or minimum demand are relevant to the specific *kinds* of generation that are needed in the NEM, and how those generators and loads behave.

More generally speaking, changes in the level of demand and consumption of energy are relevant to both the reliability and security of the NEM. This section identifies several of the key trends in demand and consumption.[190]

3.1.1 Key trends

The key trends in electricity demand and consumption include:[191]

- **Residential consumption:** Total residential consumption is expected to rise from 2017/18 to 2022/23 due to:
  - an increase in new connections, driven by population growth
  - an increase in the number of appliances
  - gas to electric appliance switching.

  In the short to medium term, this increase in consumption is projected to be offset by a sustained rooftop PV uptake and the use of more energy-efficient appliances. However, after 2022/23, residential consumption is expected to increase to a greater extent. This is due to the projected decline in PV installations and significant uptake of electric vehicles. In the longer term, electric vehicles are also expected to underpin increasing demand for electricity.
- **Business consumption:** Business sector consumption is forecast to continue growing as forecast economic conditions improve in many sectors. However, total business consumption served by the NEM power system (i.e. served by the grid) is projected to increase only marginally, mainly due to the forecast growth of rooftop PV penetration in the business sector. After 2022/23, modest growth of consumption from the grid is forecast. This is because consumers are expected to spend more on goods and services due to the projected increases in household disposable income and gross state product.
- **Rooftop PV:** There is an expectation of continued strong growth in generation from rooftoop PV, with 2017/18 exhibiting the highest period of growth in the sector in terms of new capacity installed. From 2017/18 to 2022/23, the high growth rate will continue. According to AEMO, this is partially due to high retail prices and small-scale technology certificates (STCs) subsidy. Another factor that will drive residential rooftop PV installations is incentives introduced by some state governments such as Victorian Solar Homes program.[192] After 2022/23, the growth rate is projected to decline, as retail prices are forecast to lower and STC incentives fall to zero by 2030.

190 The demand and consumption measured throughout this chapter are operational demand and consumption. Operational demand and consumption refers to electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units. Consumption refers to electricity used over a period of time. Demand describes electricity usage at a particular instance.

191 The key trends are based on AEMO, *2018 Electricity Statement of Opportunities* (ESOO), August 2018. The ESOO is a document prepared by AEMO every year that examines likely demand and supply trends in the national electricity market in the near to medium term.

192 Solar Homes program discussed in more detail in section 4.5.3.

- **Battery storage:** AEMO forecast that by the end of its 20-year outlook period, there will be 2.6 GW of behind-the-meter battery storage. Interestingly, this is less than half the level of uptake projected in the *2017 ESOO*.
- **Maximum operational demand:** Over the next five years, maximum underlying demand levels are projected to be relatively stable in most regions. However, patterns of maximum operational demand are expected to change. It is expected to occur later in the day due to growth in installed rooftop PV capacity.[193] This will limit the ability of additional rooftop PV to offset other demand drivers, such as connections growth and appliance uptake.[194]
- **Minimum operational demand:** Minimum demand is forecast to fall rapidly over the next five years - that is, minimum demand levels are expected to become more negative. Patterns of when minimum demand occurs during the day are also expected to change, with all regions expected to experience minimum demand in the middle of the day within the next two years. According to AEMO, high rooftop PV uptake is the main driver of this trend.

3.1.2 Consumption

Under AEMO's neutral scenario included in the *2018 Electricity Statement of Opportunities*, underlying electricity consumption[195] is projected to increase in the NEM by approximately 1.3 per cent per year over the next 20 years.[196] This is due to the growth in:

- population
- gross state product
- manufacturing output.

While total energy consumption is expected to increase, the amount of energy actually consumed from the grid is expected to remain relatively flat.[197] This is due to the strong uptake of rooftop PV in the medium term, which has the effect of displacing power taken from the grid. Figure 3.1 shows that:

- In 2017/18, energy consumption[198] was 183.5 TWh. Over the coming five years this is projected to remain relatively flat, with energy consumption being 183 TWh in 2022/23 (see *2018 ESOO operational forecast* line in the chart). This is because rooftop PV is expected to offset forecast growth in total energy consumption.
- After 2022/23, moderate growth in energy consumption is projected, as the PV installation rate is forecast to decline.

193 South Australia has already experienced its maximum at around 20.00 in the summer of 2017/18.

194 The impact of appliance uptake will be further exacerbated by the extent to which gas heating is replaced with electrical heating by residential users.

195 Underlying electricity consumption means all the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' rooftop PV and battery storage.

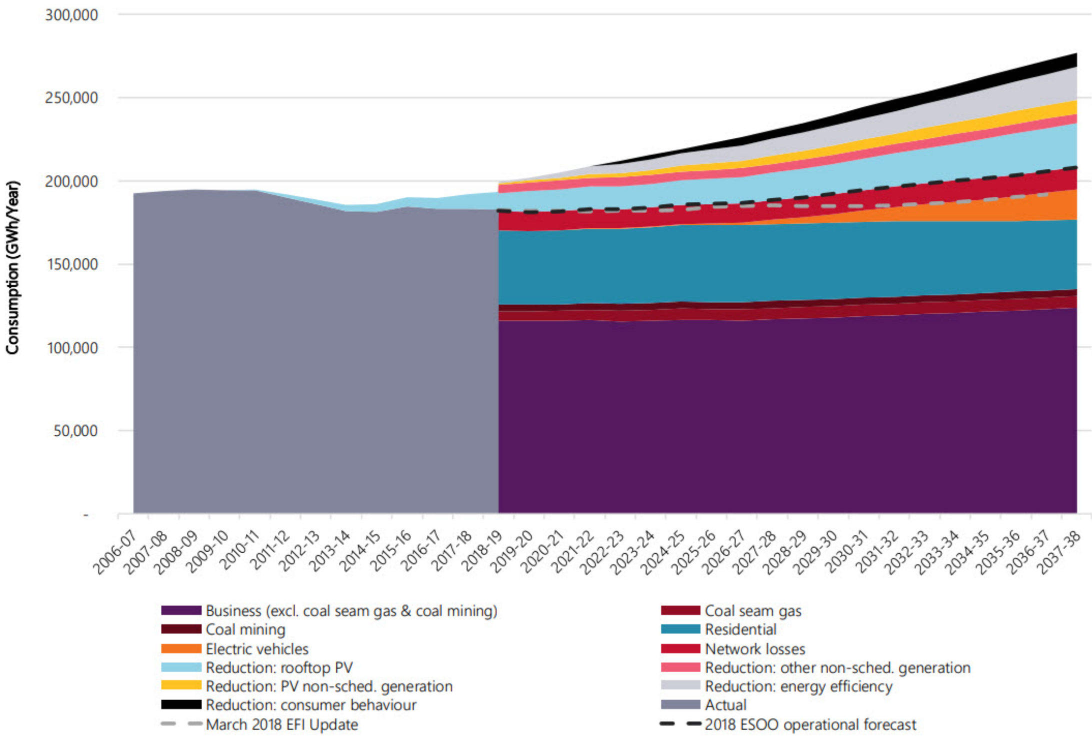
196 AEMO, *2018 Electricity Statement of Opportunities*, August 2018.

197 This is the consumption to be supplied to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (excluding their auxiliary loads, or electricity used by the generator).

198 Operational consumption refers to the electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generators.

- In the long term, electric vehicles are projected to drive growth in electricity consumption, contributing to a total of 16 TWh forecast increase in consumption by 2037/38.

Figure 3.1: Actual and forecast NEM electricity consumption, neutral scenario



Source: AEMO, *2018 Electricity Statement of Opportunities*, August 2018, p. 37.

Note: Neutral scenario assumes a range of mid-point projections of economic growth, future demand growth, electric vehicle uptake and fuel costs, and existing market and policy settings. It also assumes moderate growth in DER aggregation, such that aggregated distributed batteries can be treated and operated as virtual power plants rather than operated to maximise the individual household's benefit.

3.1.3 Maximum and minimum operational demand

The NEM continues to see a number of changes in both patterns of maximum and minimum demand.

In particular, increased volumes of rooftop PV in the NEM are driving changes in demand patterns. This is not only driving changes in the absolute levels of minimum and maximum demand, but also when maximum and minimum demand are likely to occur during the day. These changes are having, and will continue to have, material implications for the required generation and load mix in the NEM, and how the power system is operated.

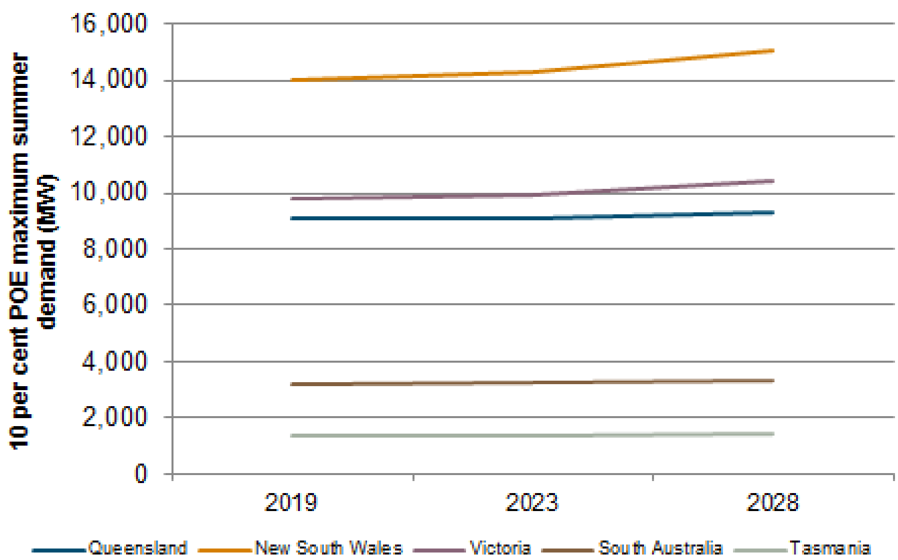
This section considers some of the key trends in both maximum and minimum demand, both of which are influenced by the increased uptake of rooftop PV generation.

Maximum demand

Forecasts of maximum annual demand are strongly driven by weather, and occur at different times in different regions.[199] This means that there is no NEM-wide coincident maximum or minimum against which supply is assessed.[200]

For all NEM regions, except Tasmania, maximum demand is observed in summer. Summer maximum demand is influenced strongly by residential air conditioning loads. In Tasmania, winter maximum demand is being driven by heating needs. Figure 3.2 shows the forecast 10 per cent probability of exceedance (POE) maximum summer demand for each region.[201]

Figure 3.2: Forecast maximum summer demand



Source: based on AEMO data sourced from *2018 Electricity Statement of Opportunities*, August 2018.

Figure 3.3 shows the forecast 10 per cent POE maximum winter demands.

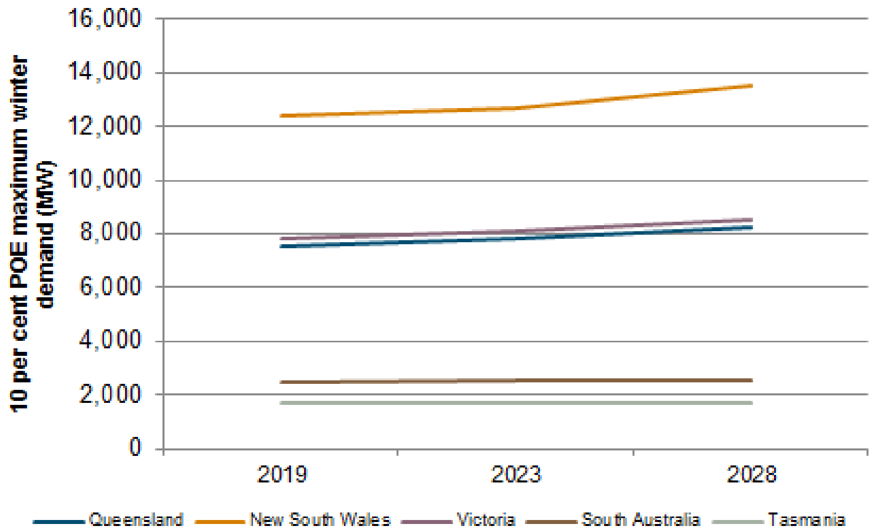
199 AEMO only forecasts maximum demands for individual regions and does not add regional peak demand forecasts together to get a "NEM peak". Reason for not producing NEM peak is that it depends on the diversity of regional peaks, which changes from year to year to an extent that makes a forecast NEM maximum demand unmeaningful. However, AEMO also acknowledges that it is not uncommon for high demand conditions to be experienced across multiple regions. For instance, when South Australia's demand is high, the region (whose power system is connected only to Victoria) relies on Victoria having enough capacity to export to South Australia, above its own need for electricity. If Victoria's supply-demand balance does not allow these exports, South Australia's risk of a shortfall increases. Source: AEMO, *Summer operations 2017-18*, November 2017.

200 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 44.

201 Probability of exceedance is the probability, as a percentage, that a maximum demand level will be met or exceeded. It is usually abbreviated to POE. For example, a ten per cent POE forecast of maximum demand is expected to be met or exceeded on average one year in ten. If 10POE demand is, say, 9,000 MW, this implies that there is a ten per cent probability that demand is higher than 9,000 MW. Another way of putting this is that demand may be higher than 9,000 MW one in every ten years.

Maximum and minimum demand forecasts can be presented with a 50 per cent POE – meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions – or a ten per cent POE (for maximum demand) or 90 per cent POE (for minimum demand), based on more extreme conditions that could be expected one year in ten (also called 1-in-10).

Figure 3.3: Forecast maximum winter demand



Source: based on AEMO data sourced from *2018 Electricity Statement of Opportunities*, August 2018.

For all states maximum summer and winter demand is projected to slightly increase or remain relatively flat. Over the 10-year outlook the highest growth rates of maximum summer and winter demands in the NEM are projected in New South Wales and Victoria. For both states the projected growth rates over the total time period are:

- seven per cent for maximum summer demand
- 9.5 per cent for maximum winter demand.

The key points for forecasts of maximum demand are:[202]

- Between 2017/18 and 2022/23, maximum demand is projected to be generally flat. After 2022/23, maximum demand is forecast to grow by around one per cent annually to 2037/38. This is explained by the declining contribution of PV generation in future.
- Forecast maximum operational demand is projected to shift later in the day due to a declining ability of rooftop PV to offset demand. South Australia and Tasmania[203] are the exceptions to this.
- South Australia has already experienced its maximum demand at around 20.00 in the summer of 2017/18. This is expected to continue occurring around this time.

202 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 45.

203 Tasmania is winter peaking. As maximum demand is driven by heating load, it occurs after sunset.

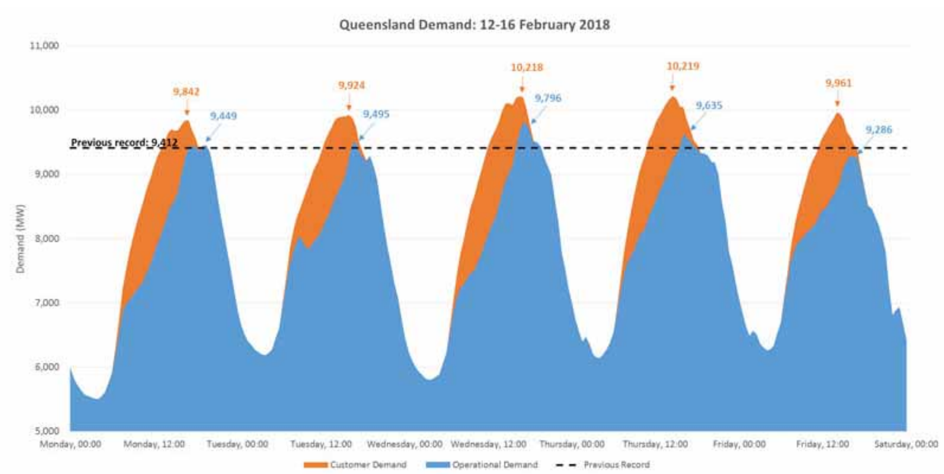
Summer peak demand in Queensland

From 12 February to 16 February 2018, Queensland experienced an intense heatwave. Temperatures were nine degrees above average in some parts of the state, with two consecutive days averaging over 40°C across the state for the first time.[204]

These weather conditions led to new records for operational demand, as homes and businesses turned to their air-conditioning to stay cool.[205] The previous record operational demand for Queensland was 9,412 MW, set in January 2017. This record was exceeded four times during the heatwave event[206], setting a record of peak demand of 9,796 MW. This is an increase of nearly 400 MW, which, by way of comparison, is roughly the energy required to power a mid-sized town of 150,000 customers.[207]

Figure 3.4 shows operational demand in Queensland between 12 and 16 February 2018. The figure below demonstrates the impact of rooftop PV that considerably reduced peak demand, which can help to reduce the cumulative stress on the power system that can occur on peak demand days.[208] The peak demand on 12 February occurred at 19:30 and those on 13 and 14 of February were reached at 17:00.

Figure 3.4: Queensland demand between 12 and 16 February 2018



Source: AEMO Energy Live, *Queensland's record-breaking demand explained,* 23 February 2018.
Note: Previous record showed on the figure is the previous record of generation demand.

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204 Prior to this event there had only been two days on record in February where the Queensland state-wide average maximum temperature had exceeded 40 °C – once in 1935 and once last year.

205 76 per cent of homes in South East Queensland now have air conditioning compared with 45 percent in 2004. Energy Networks Australia, *Qld sets demand record again...and again...and again by Emma Watts,* 1 March 2018, https://www.energynetworks.com.au/news/energy-insider/qld-sets-demand-record-againand-againand-again, accessed 11 September 2018.

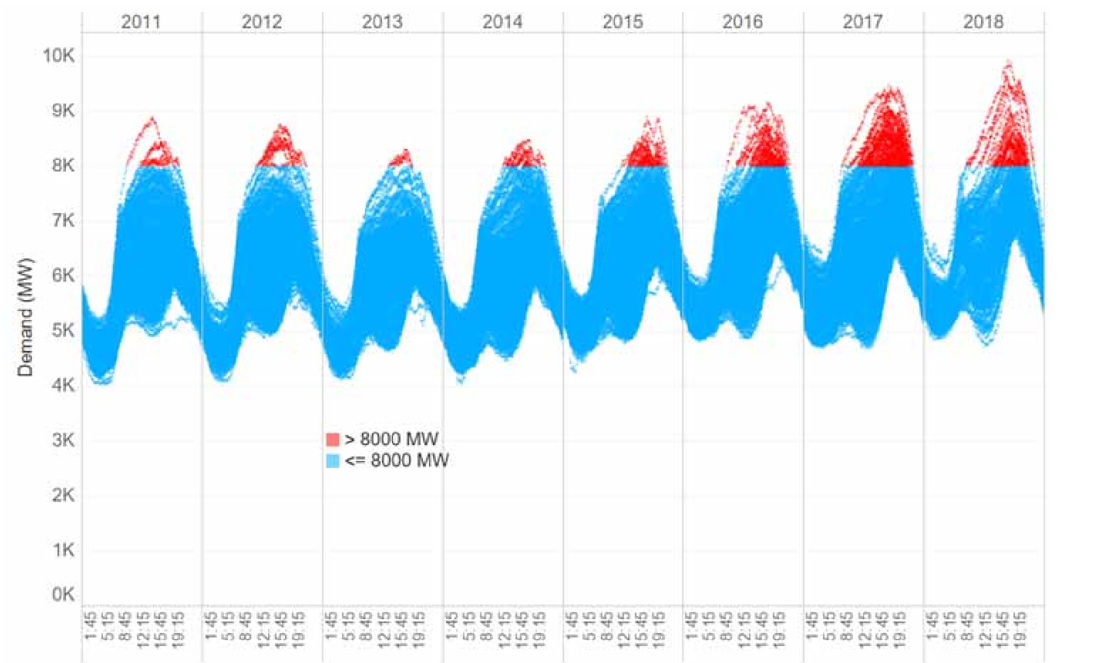
206 On 12 February 2018 (9,449 MW), 13 February 2018 (9,495 MW), 14 February 2018 (9,796 MW) and 15 February 2018 (9,635 MW).

207 AEMO Energy Live, *Queensland's record-breaking demand explained*, 23 February 2018.

208 This depends on the timing of peak demand and weather conditions. If peak demand occurs during the day when the sun is shining, energy produced by residential rooftop PV systems may diminish the cumulative stress on the power system by helping to reduce the extent of peak demand. If peak demand occurs at the evening, solar PV will not be able to assist with meeting this demand.

Summer demand in Queensland has been increasing since 2013. Figure 3.5 below demonstrates Queensland demand outcomes by time-of-day and year from 2011 to 2018.

Figure 3.5: Queensland demand outcomes by time-of-day



Source: AEMC analysis.
Note: Each point on the chart represents demand in a single dispatch interval. All points exceeding 8,000 MW are coloured in red.

Increasing summer peak demand in Queensland is due to growth in residential cooling load and in demand by the coal seam gas sector. It continues to be a significant pressure on future network capacity requirements.

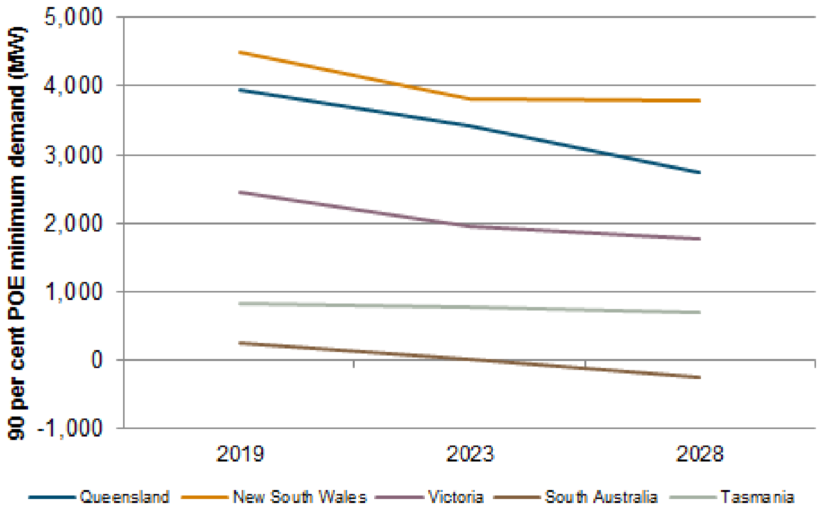
Minimum demand

From 2019 to 2023, minimum demand is forecast to decline in all NEM regions, mainly due to projected high rooftop PV uptake.[209]

Figure 3.6 shows the forecast 90 per cent POE minimum summer demand for each NEM region. A 90 per cent POE forecast is a forecast that is expected to be exceeded in nine years in ten. In Figure 3.6, this means that the actual minimum summer demand is expected to be lower than the levels shown for one year in ten.

209 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 46.

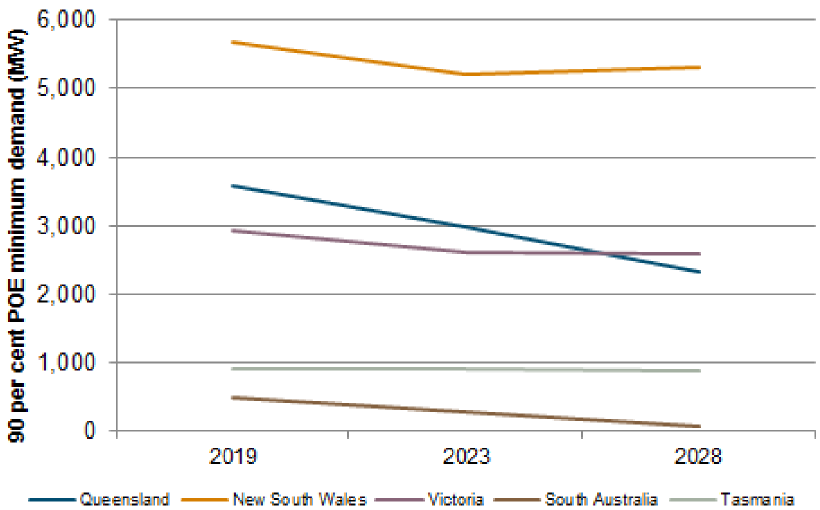
Figure 3.6: Forecast minimum summer demand



Source: based on AEMO data sourced from *2018 Electricity Statement of Opportunities*, August 2018.

Figure 3.7 shows the forecast 90 per cent POE minimum winter demands.

Figure 3.7: Forecast minimum winter demand



Source: based on AEMO data sourced from *2018 Electricity Statement of Opportunities*, August 2018.

Some key trends include:

- Between 2019 and 2028, minimum summer demand in South Australia is projected to fall from 250 MW to -244 MW for 90 per cent POE, and minimum winter demand from 494 MW to 87 MW for 90 per cent POE over the same period.
- Between 2019 and 2028, minimum summer demand in Queensland is projected to fall from 3,949 MW to 2,740 MW for 90 per cent POE, and minimum winter demand from 3,573 MW to 2,324 MW for 90 per cent POE over the same period.

South Australia minimum demand

In relation to forecasts of 90 per cent POE minimum demand, the Panel also notes:

- Increasing residential rooftop PV uptake is expected to result in all regions experiencing minimum demand in the middle of the day within the next year or two.[210] This is exemplified in South Australia, which has already experienced a shift in the occurrence of minimum demand, as well as a general decrease in the absolute level of minimum demand. Figure 3.8 shows how levels of minimum demand in South Australia have been both decreasing in absolute terms,[211] as well as shifting toward a pattern where minimum demand occurs around midday, since 2011.[212]
- In South Australia, the lowest level of minimum demand is expected to become negative by 2023/24[213] for 90 per cent POE.[214] This means that generation output in the region will exceed demand, mainly driven by output from residential rooftop PV generation in some hours. Figure 3.9 shows the projected changes in operational demand in South Australia from 2016/17 to 2036/37.

210 Historically, minimum demand levels have tended to occur overnight.

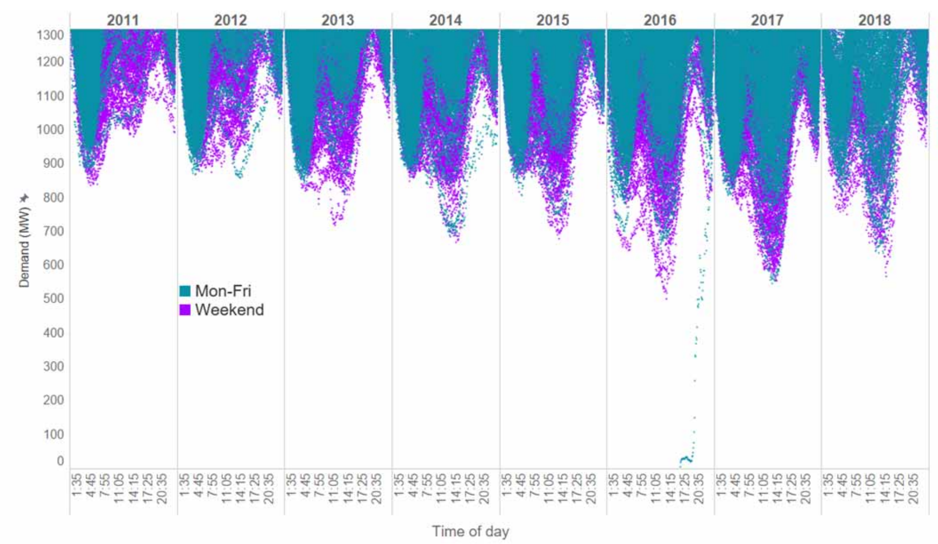
211 South Australia set a new all-time minimum demand record of 599 MW at 1pm on 21 October 2018. This represents a continuation of the decreasing average daytime demand, primarily driven by increasing rooftop PV uptake. AEMO, *Quarterly Energy Dynamics - Q4 2018*, February 2019, p. 3.

212 Similarly, Tasmania experienced minimum demand at midday in 2017/18.

213 Notably, this is one year earlier than previously projected by AEMO. Source: AEMO, *2018 Electricity Forecasting Insights*, March 2018.

214 AEMO, *2018 Electricity Statement of Opportunities*, August 2018, p. 47.

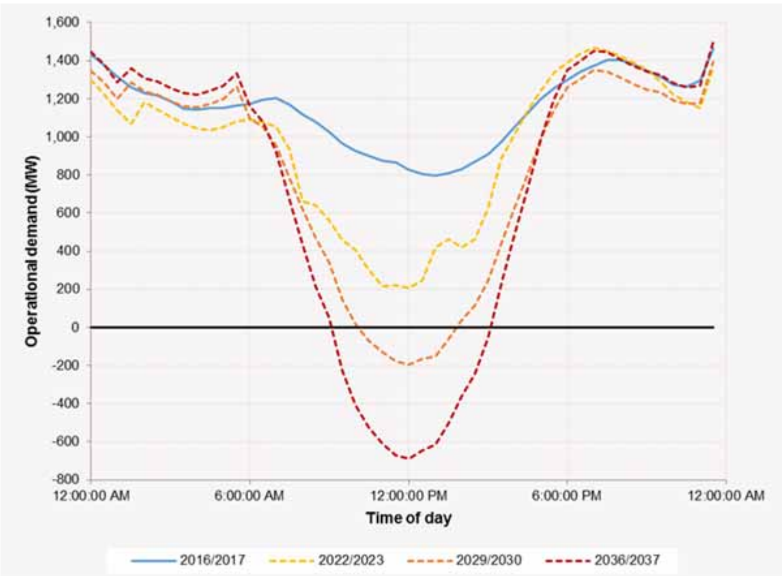
Figure 3.8: South Australia demand outcomes below 1300 MW



Source: AEMC analysis.

Figure 3.9 below also demonstrates the way in which minimum demand shapes are forecast to change in the longer term in South Australia. This phenomenon of the 'hollowing out' of the demand curve during the middle of the day has been observed in many jurisdictions and is commonly associated with increased residential rooftop PV displacing demand.

Figure 3.9: Projected changes in operational demand in South Australia



Source: AEMO.

AEMO has identified that the key driver of these changes in South Australia is high solar PV uptake. More than 30 per cent of households in South Australia now have rooftop PV systems installed. High adoption rates of rooftop PV and PV non-scheduled generation (between 100 kW and 30 MW) not only reduce the requirements to source electricity from grid-based generators, but also change the load shape at an unprecedented level.[215] While South Australia may be ahead of other jurisdictions in terms of the degree of rooftop solar PV penetration, it provides an example of the challenges associated with the significant shift in generation technology that is currently underway.

The shift in timing and general reduction in levels of South Australia minimum demand may have a number of implications for operation of the system. AEMO has also stated that: '[...] reduction in minimum operational demand [...] would result in more periods where there is little generation supplied by centrally managed generators to control the system. It may also reduce maintenance windows, as synchronous generation may be directed online to manage system strength'.[216]

AEMO consider that these effects of increased residential rooftop PV, and distributed energy resources (DER) more generally, can present a number of operational and system security challenges, including:

- system strength[217] risks
- voltage and frequency control issues
- the need for more sophisticated reserve management
- challenges for protection and control schemes operation, including emergency frequency control schemes.

In terms of maximum demand, increased penetration of residential rooftop PV systems can reduce peak demand, which can help to reduce the cumulative stress on the power system that can occur on peak demand days.[218] However, an increased penetration of variable renewable generation in the system can also result in an increased rate of change in the supply and demand balance within a day, which the rest of the system must respond to.

In the context of minimum demand reduction and its shift to midday, having enough flexible capacity in the NEM available to 'ramp up' quickly is also a consideration that will need monitoring. Ramping, and in particular ramping availability, is a reference to the availability of generation or scheduled load to be dispatched in response to changes in supply and demand in a timely manner. Achieving a balance of supply and demand may be more challenging in

215 AEMO, *2018 Electricity Statement of Opportunities*, August 2018, p.28.

216 Ibid, p. 46.

217 System strength is a property of the power system that resists changes in voltage in response to a change in loading conditions. It is also related to the level of current that can flow into a short circuit at a particular point in the power system, with low system strength conditions corresponding to low levels of available fault current. This availability of fault current affects the ability of system protection systems to operate correctly and the stability and dynamics of generator control systems.

218 This depends on the timing of peak demand and weather conditions. If peak demand occurs during the day when the sun is shining, energy produced by residential rooftop PV systems may diminish the stress on the power system by helping to reduce the extent of peak demand. If peak demand occurs at the evening, solar PV will not be able to assist with meeting this demand.

the future due to an increased penetration of variable renewable generation in the system and a more responsive demand side of the market.[219] This is because it may result in:[220]

- An increased rate of change of the supply and demand balance which the rest of the system must respond to. For example, the sun setting across the eastern coast of Australia may result in a relatively rapid decrease in solar PV generation at the same time as a rise in demand in the late afternoon. The remaining generation portfolio (and demand side participants) must collectively be able to change output in step to maintain a balance of supply and demand.
- A greater unpredictability in the supply and demand balance. For example, a sudden and unexpected drop off in wind may decrease generation output. Similar impacts may occur due to a sudden and unexpected decrease in demand. Again, the remaining system must collectively be able to change its supply and demand response in order to maintain reliability.

The AEMC has undertaken work on the historical value of ramping in the spot market. The AEMC concluded that existing market signals are sufficient to maintain sufficient flexible generation in the immediate future, but that this is an area that requires ongoing consideration.[221]

However, the Panel notes that in November 2017, the AEMC made a final rule to change the settlement period for the electricity spot price from 30 minutes to five minutes, starting in July 2021. This will provide better price signals to match supply to demand. This will stimulate investment in fast response technologies, such as batteries, new generation gas peaker plants and demand response, which are particularly suited to providing this kind of fast ramping response.[222]

During periods of minimum demand where levels of energy generated exceed demand, generation may need to be curtailed. Alternatively, however, this excess energy could be stored or exported to the rest of the NEM via interconnectors, provided they are in service. Other options also exist to manage this situation, such as changing patterns of demand. For example, in response to forecasts of negative minimum demand the 'controlled load' of electric hot water systems could be shifted from the night-time to midday hours. However, shifting this controlled load may involve significant expense.[223]

AEMO has noted further security implications of high penetrations of DER, particularly distributed residential rooftop PV systems. This was examined by AEMO following the system separation event on 25 August 2018.[224] AEMO concluded that the distributed fleet of small scale, residential rooftop solar PV generally contributed to assist over-frequency management in Queensland and South Australia over the course of the event by reducing output. However,

219 AEMC, *Reliability Frameworks Review*, final report, July 2018, p. 61.
220 Ibid.
221 Ibid.
222 For more information, see: https://www.aemc.gov.au/rule-changes/five-minute-settlement
223 Reliability Panel, *2017 Annual market performance review*, March 2018, p. 22.
224 This event is discussed in more detail in chapter 5.

in Victoria or New South Wales, residential rooftop solar PV provided no marked assistance.[225] Detailed analysis of the performance of a sample group of inverters showed:[226]

- approximately 15 per cent of sampled systems installed before October 2016 dropped out during the event
- of the sampled systems installed after October 2016, around 15 per cent in Queensland and 30 per cent in South Australia did not provide the over-frequency reduction capability required by the applicable Australian standard.

In response to this, AEMO recommended:[227]

- immediately assess technical requirements of inverters
- work with stakeholders to implement improved performance standards for inverters by end of 2019
- establish solutions for obtaining data on the performance of distributed residential rooftop PV systems, and to develop the necessary simulation models to predict their response to system disturbances progressively up to the end of 2020.

Integrated PV and storage systems

Integrated PV and storage systems allow for the output of PV generation to be stored during the day and then used during evening peaks. A potential implication of this is to smooth out the midday troughs and late afternoon peaks in the demand curve caused by solar PV without storage, as described above.

Integrated PV and storage systems also provide an opportunity for the provision of other services to the market, such as providing frequency control or other ancillary services. Depending on how these services are valued, priced and procured, this may have an impact on the way that storage is used, including when it is charged and discharged, or whether a consumer uses the power stored in the battery, or exports it to the market.

Further, AEMO projects that in the long term (after 2027/28) the number of electric vehicles will significantly increase, underlying the growing demand for electricity. By 2037/38, 5.5 million electric vehicles NEM-wide are forecast.[228] Electric vehicles charging patterns will impact the daily load profile and maximum demand. Charging is likely to be influenced by the tariff structures, availability of public infrastructure, any energy management systems, and the driver’s routine.

These kinds of changes in the shape and timing of the demand curve can have implications for what kind of generation is needed, and when it is needed, to meet consumer demand.

Finally, the Panel notes integrated PV and storage systems may also influence how customers value the reliability of the supply of electricity from the grid, as these systems may at least

225 AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018*, January 2019, p. 6.

226 Ibid.

227 Ibid.

228 Around 2,400 electric vehicles were sold in the NEM during 2017, representing 0.2 per cent of new light vehicle sales. AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 30.

partly insulate households and small businesses from the impacts of interruptions in grid supply.[229]

3.2 Generation capacity, retirement and investment

This section identifies and describes the main changes to the generation mix.

3.2.1 Key trends

The key trends in the NEM generation mix are:

- **Retirement and ageing of synchronous, thermal generation:** The retirement of over 2,300 MW of synchronous thermal generation within the next 10 years has been announced.[230] Further, a large amount of existing synchronous thermal coal generation will reach the end of its expected operating life over the coming two decades.
- **Increase in intermittent renewable generation:** The NEM has experienced a significant growth in large-scale intermittent renewable generation. In 2017/18, around 1.2 GW of new generation was commissioned and 5.5 GW was committed.[231] This commissioned and committed generation was mostly comprised of large scale solar and wind projects.[232]
- **Increase in distributed energy generation:** The 2017/18 financial year saw the highest period of growth for rooftop PV installations. In 2017/18, approximately 1,300 MW of new rooftop PV capacity was installed, bringing the total rooftop PV capacity in the NEM to about 6,500 MW.[233] To put this in perspective, 6,500 MW is approximately 13 per cent of the total installed large scale generation in the NEM.[234]

Changes in the generation mix have implications for the security of the NEM. There is an increasing difficulty of maintaining the system in a secure state as the market transitions to new generating technology. In particular, changes in the ratio of synchronous and asynchronous generation in the NEM may decrease the amount of physical inertia available and can also reduce system strength, both of which can impact on key system security parameters. Reductions in availability of synchronous generation may also affect the ability of AEMO and network service providers to manage voltage and stability limits in the NEM, as synchronous generation traditionally provided this capability as an inherent aspect of operation.

229 The Panel notes that the capability of most small scale concurrent PV/battery systems to provide an 'uninterrupted power supply' type service depends on the configuration of the inverter that connects the generator to the power system. Many currently installed inverters can only function when the grid is fully energised and are therefore unable to provide these kinds of services if there is a blackout. However, systems can be retrofitted to provide this functionality.

230 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 48.

231 Commissioned generation projects are those that are in the final stage of connecting to the NEM. Immediately following commissioning, a generator can begin commercial operation. Committed generation projects refer to proposed projects that have satisfied a number of criteria that relate to: acquisition of a site, procurement of the components needed to build the generator, relevant planning approvals, obtaining finance and a final construction date.

232 AEMO, *Generation Information Page,* accessed at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

233 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 27.

234 As at 31 October 2018, total installed large scale generation in the NEM was 50,544 MW. AEMO, *Generation Information Page*, accessed on 3 December 2018, at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

The Panel notes that the market is adapting to the technology transformation that is currently occurring in the NEM, and that there are a number of examples of new technologies and approaches being integrated and trialled in the NEM to provide new system services, including frequency support from battery storage, wind farms, load aggregators and virtual power plants.

These trends may also have impacts on the reliability of the NEM by influencing the supply-demand balance. While there has been significant investment in new generation capacity in recent years, much of this capacity is intermittent, semi-scheduled or non-scheduled generation. This means that during periods when this generation is unavailable, there may be increasingly tight supply demand outcomes in the market, which could have implications for reliability.[235]

In relation to the reliability, there have been numerous announcements and market developments that show that the market is responding to the challenges of a changing generation fleet, with a host of new and innovative products being introduced, many of which are focussed on the demand side and the provision of firming products.[236] However, it should be noted that currently these initiatives are of limited capability to address security issues emerging in the system. A few examples include:

- Reflecting an increasing focus on the demand-side, Powershop and Reposit Power are working together on a program *Grid Impact* that will help Powershop dispatch surplus solar battery capacity during demand peaks.[237]
- Reflecting an increasing focus on the demand-side and technological developments, FlowPower is introducing new products that allow business customers to be exposed to market signals and wholesale power prices, and gives its customers the ability to control load in response to price fluctuations.[238]
- Similarly, another example of facilitating the demand side is Greensync's Decentralised Energy Exchange (deX). The platform allows distributed energy resources to participate in energy markets by making them visible and enabling stored energy to be dispatched on command.[239]
- Reflecting the changing generation mix, participants are also starting to look to create balanced portfolios to manage risks in the wholesale market as the generation mix transforms. For example, on 1 February 2018 Meridian Energy entered into an agreement to purchase three hydro power stations from Trustpower, and signed three power purchase agreements for wind and solar projects in Victoria and New South Wales. It was noted that 'having a balanced portfolio of wind, solar and hydro allows [Meridian] to more effectively manage risk in the market'.[240] Similarly, Tilt Renewables plans to build a 44 MW solar farm and 21 MW battery system to connect to its existing wind farm in Snowtown.

235 AEMC, *Reliability Frameworks Review*, final report, July 2018, p. 61.

236 Ibid, p. 25.

237 See: http://www.afr.com/news/powershop-reposit-power-join-virtual-power-plant-stampede-201803 13-h0xe3s

238 See: https://flowpower.com.au/we-announce-a-change-in-ownership/

239 See: https://dex.energy/.

240 Powershop, Media Release, *Meridian Energy Australia invests in renewable energy by adding hydro, solar and wind projects to meet ongoing customer growth*, 1 February 2018.

It also plans a 300 MW pumped hydro energy storage project in South Australia's disused Highbury quarry.[241]

- AGL has announced a new derivative product that seeks to 'firm up' wind generation. The product is a financial derivative that is exercised when wind generation across a region starts to fall. By financially firming up wind generation, the owners of wind farms can enter into swap contracts with other parties.[242] Similarly, in November 2018, Snowy Hydro announced the signing of eight wind and solar contracts, totalling 888 MW. The renewable energy contracted will enable Snowy Hydro to offer competitive, firm wholesale prices (i.e. the cost of renewable energy plus the cost of 'firming') for below $70/MWh for a flat load, for up to 15 years.[243]
- ERM Power introduced a solar firming product to 'help manage the risks of intermittent generation'. The product will help support investment in renewables by providing fixed price certainty for organisations wanting to hedge solar generation production.[244]

While there are a number of examples of the market responding to the challenges of a changing generation mix, a number of regulatory work programs are also underway to help manage this issue.

For example, in October 2018, the COAG Energy Council agreed to progress the Retailer Reliability Obligation. The Retailer Reliability Obligation mechanism aims to incentivise retailers, and other large users, to invest in dispatchable electricity generation in the NEM regions, where it is expected there will be a gap between generation and forecast peak demand.[245] The Retailer Reliability Obligation is a long term solution to ensure reliable electricity supply. If a generation gap is forecast, liable entities will be required to demonstrate they can meet their share of peak demand, for example, by having firm on-demand contracts related to the purchase or sale of electricity from the wholesale market.[246]

Further, on reliability the AEMC is currently assessing:

- the introduction of a mechanism for wholesale demand response in the NEM[247]
- the overall RERT[248] framework[249]
- the effectiveness of the interventions framework in light of the increasing use of directions by AEMO.[250]

241 Tilt Renewables, *Tilt Renewables announces two exciting new energy projects for South Australia,* media release, 7 February 2018.

242 AGL, *Making wind energy dispatchable energy*, AGL Energy Sustainability Blog – Corporate, 6 April 2018, accessed on 12 June 2018, at: http://aglblog.com.au/2018/04/making-wind-energy-dispatchable-energy/

243 For more information, see: https://www.snowyhydro.com.au/news/shl_deals/

244 For more information, see: http://https://www.ermpower.com.au/new-generation-financial-products-launched-support-renewables/

245 COAG Energy Council, *Meeting Communique*, 26 October 2018.

246 Ibid.

247 For more information, see: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

248 The RERT is a type of strategic reserve that allows AEMO to pay a premium for additional capacity to be on stand-by in case of emergencies when the demand and supply balance is tight.

249 For more information, see: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

250 For more information, see: https://www.aemc.gov.au/sites/default/files/2019-02/System%20security%20and%20reliability%20action%20plan.pdf

To address security emerging issues and keep the system stable, the AEMC made the following rules to:

- significantly change technical performance standards for generators seeking to connect to the national electricity grid and the process for negotiating those standards. The final rule establishes a flexible approach to setting standards that enables targeted, least-cost ways of connecting new generators. The rule also amends a number of the standards themselves.[251]
- enable better frequency control by making networks provide minimum levels of inertia and, with AEMO approval, enabling networks to contract with suppliers to provide inertia substitutes.[252]
- keep the system stable by making networks provide minimum levels of system strength at key locations, and requiring new generators to pay for remedial action if they impact system stability.[253]
- establish a register of distributed energy resources, including small-scale battery storage systems and rooftop solar. The register will give network businesses and AEMO visibility of where distributed energy resources are connected to help in planning and operating the power system as it transforms.[254]

These reliability and security impacts of a changing generation mix are explored further in chapters 4 and 5, as well as a more detailed description of the market and regulatory developments underway that are addressing these impacts.

3.2.2 Changes in electricity generation

The actual amount of energy produced by a generator, or generator output, is different from generation capacity. Capacity is the maximum rated electrical output of a generator at a specific point in time and is typically measured in megawatts (MW). Generation output, or energy, is the amount of electrical output that a generator produces over a specific period, and is typically measured in megawatt hours (MWh).

Generation energy output

The generation mix is changing in the NEM. Figure 3.10 demonstrates the percentages of total output per technology type from January 2012 to July 2018. The main changes were:

- There was a slight decrease in electricity generated from coal. Mainly, this was due to the fall in energy generated by brown coal thermal generators.
- Energy generated from hydro and wind doubled in the period.

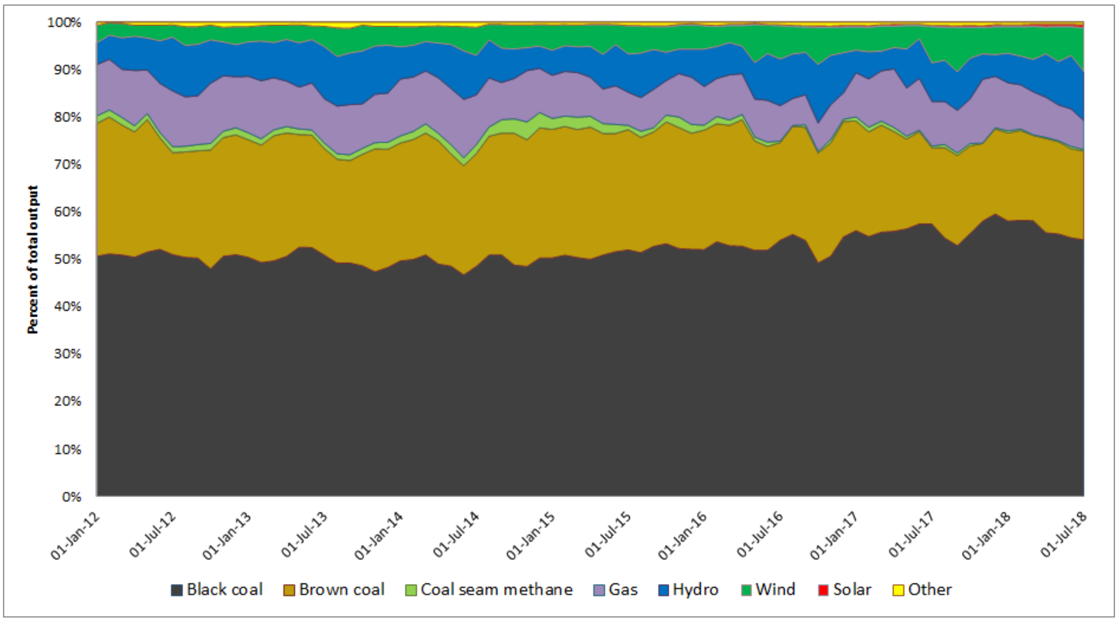
251 For more information, see: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

252 For more information, see: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

253 For more information, see: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

254 For more information, see: https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources

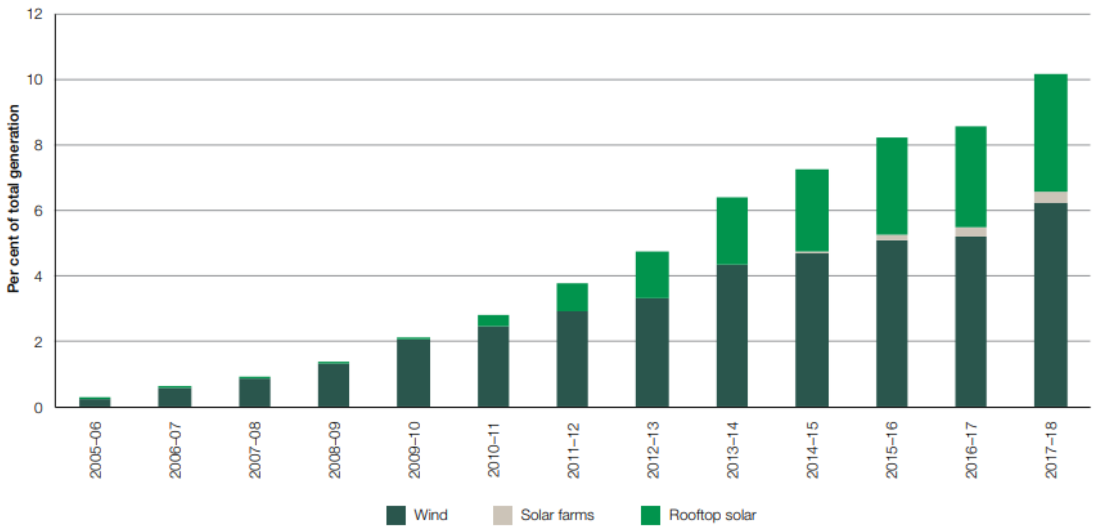
Figure 3.10: Generation output per technology type



Source: AEMC analysis of NeoPoint data.

In 2017/18, wind and solar generation share of total output in the NEM reached 10 per cent. Figure 3.11 demonstrates how the share of wind and solar in the overall generation mix has been rising rapidly in recent years.

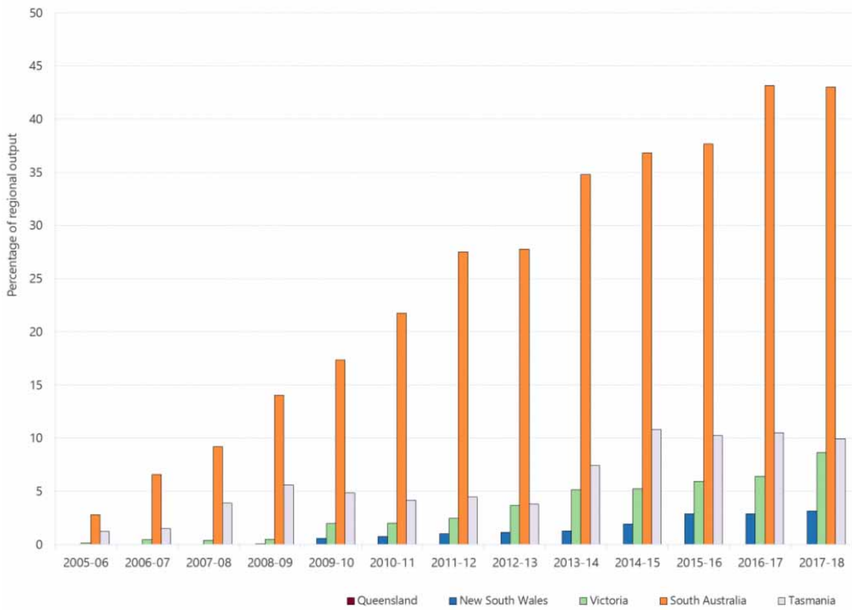
Figure 3.11: Wind and solar generation share of total output in the NEM



Source: AER, *Wholesale electricity market performance report*, December 2018.
Note: The figure includes only solar generation from larger, registered solar farms with capacity greater than or equal to 30 MW registered capacity.

Material trends can also be identified at the regional level. In particular, in 2017/18 more than 40 per cent of energy generated in South Australia was sourced from wind generation. Figure 3.12 shows wind output as a percentage of total energy generated in each region.

Figure 3.12: Wind output as a percentage of regional output



Source: AER, *Wholesale statistics page*, accessed 2 October 2018.

Generation capacity

As of 1 July 2018, the total installed generation capacity in the NEM was 49,99GW.[255] By fuel type, generation capacity was comprised of:

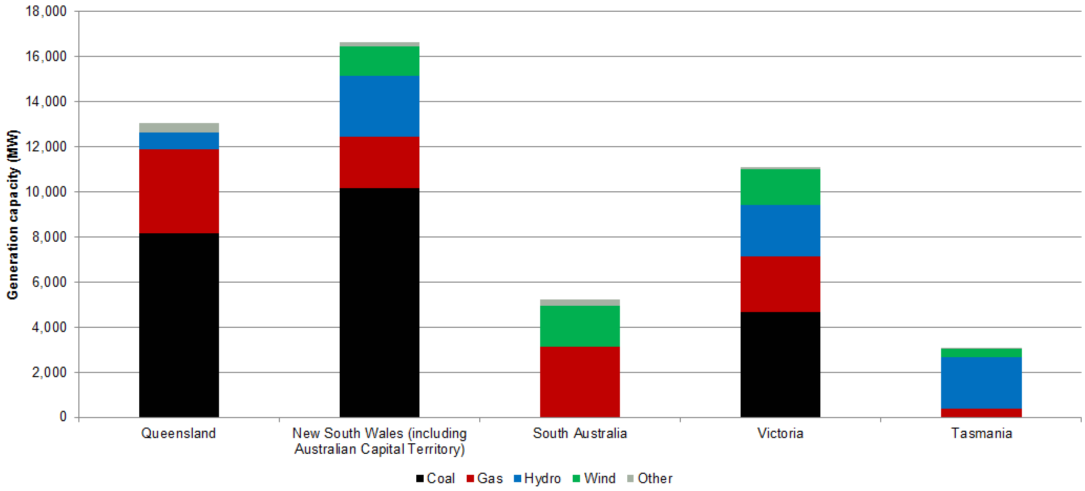
- 46 per cent coal
- 23.9 per cent gas
- 16 per cent hydro
- 10 per cent wind
- 1.9 per cent large scale solar
- 1.8 per cent other, which includes biomass and large scale storage.[256]

The regional breakdown of generation capacity is shown in Figure 3.13.

255 This figure includes scheduled, semi-scheduled, and non-scheduled installed capacity, but excludes rooftop PV. It also includes announced withdrawals.

256 In 2017/18 financial year, the only operating large scale storage in the NEM was the Hornsdale Power Reserve Battery Energy Storage System in South Australia.

Figure 3.13: Regional breakdown of generation capacity by fuel type



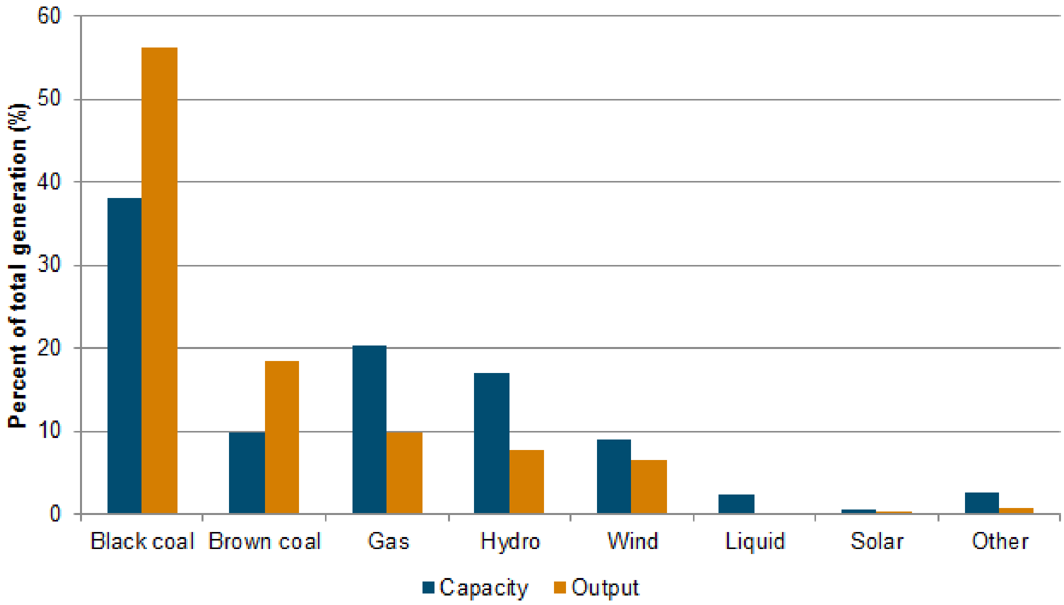
Source: Based on AEMO data, *Generator information page.*

Despite increased penetration of intermittent renewable generation and withdrawal of thermal coal-fired power generation, coal-fired thermal generation accounts for around half the installed capacity in the NEM. On a regional basis, coal-fired generation makes up a substantial portion of the generation capacity in Queensland (61 per cent), New South Wales (59 per cent) and Victoria (42 per cent). In South Australia, gas-fired generation comprises 59 per cent of the generation capacity. In Tasmania, abundant hydro resources mean that over 75 per cent of installed Tasmanian generation capacity is hydro.

Although it makes up around half of installed capacity, coal-fired thermal generation remains the dominant source of energy generated in the NEM. This is demonstrated in Figure 3.14. This is because coal-fired thermal generation typically operates steadily and generates energy for an extended period (i.e. with a high capacity factor), while other types of generation capacity operate less frequently (i.e. with lower capacity factors).[257]

257 Capacity factor is the ratio of generation capacity to generation output often expressed as a percentage. For example, if a generator had a generation capacity of 100 MW and over a year the average generation output from the generator was 80 MW, that generator would have a capacity factor of 80 per cent.

Figure 3.14: Capacity and output per technology type



Source: AER, Wholesale statistics page, accessed 29 August 2018.

Generation entry and exit

To date, the NEM has experienced a significant change in the generation mix, at least in terms of generation capacity.[258] Figure 3.15 shows the entry and exit of synchronous and asynchronous generating capacity in the NEM power system between 2007 and 2018, as well as the projected entry and exit of synchronous and asynchronous generating capacity in 2019 and 2020. The data for 2019 and 2020 includes commissioned generation and projects that AEMO has classified as committed. Commissioned generation projects are those that are in the final stage of connecting to the NEM. Immediately following commissioning, a generator can begin commercial operation. Committed generation projects refer to proposed projects that have satisfied a number of criteria that relate to: acquisition of a site, procurement of the components needed to build the generator, relevant planning approvals, obtaining finance and a final construction date.

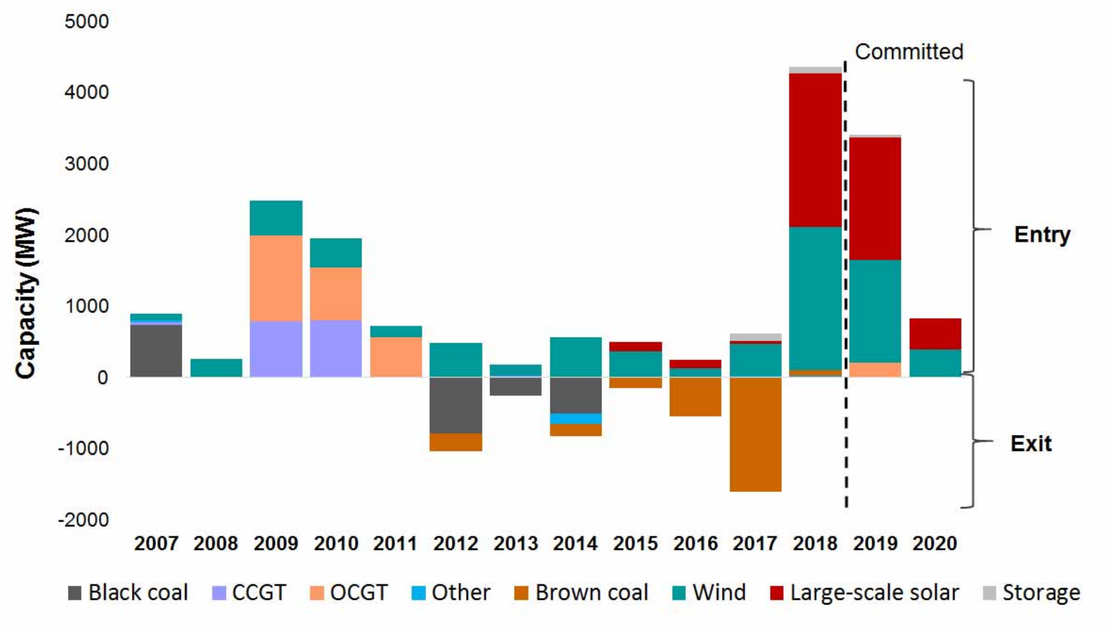
The figure demonstrates that:

- over the past seven years significant retirement of thermal coal generation occurred

258 In response, among other things, to the technology change of the generating systems seeking to connect to the power system, in August 2017 AEMO submitted a rule change request to the AEMC. The request sought changes to the access standards for generating systems in the NER and changes to the negotiating process in the NER that translates those access standards into the standard of performance required of the physical equipment that makes up and connects to the power system. On 27 September, the AEMC published the final determination on *Generator technical performance standards rule change.* For further detail refer to: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

- there was a significant entry of wind and solar generation over the past years, particularly over 2018. Projections also show material new entry into 2019.[259]

Figure 3.15: Entry and exit of generation capacity in the NEM, 2007 to 2020



Source: AEMC analysis of data provided on AEMO *Generator information page.*

Committed generation: Between 19 May 2017 and 1 July 2018[260], 5,538 MW of generation was committed. This compares to 1,312 MW of generation committed in 2016/17, 537 MW of generation committed in 2015/16 and 240 MW of generation committed in 2014/15.

In terms of capacity, the main generation projects committed in 2017/18 are:[261]

- Daydream Solar Farm (167.5 MW) in Queensland
- Coopers Gap Wind Farm (453 MW) in Queensland
- Mt Emerald Wind Farm (180.5 MW) in Queensland
- Coleambally Solar Farm (180 MW) in New South Wales
- Bulgana Green Power Hub - Wind Farm (204 MW) in Victoria
- Moorabool Wind Farm (320 MW) in Victoria
- Murra Warra Wind Farm - stage 1 (225.7 MW) in Victoria

259 The Panel notes that the number of connection enquiries with network service providers also presents a significant volume of renewable generation seeking to connect to the system. As at 21 January 2019, there were 51,568 MW of proposed generation. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

260 The analysis provided is not strictly aligned with the 2017/18 financial year. This is because data was derived from the AEMO's regional generation information pages that were published as at 19 May 2017, 22 December 2017, 16 March 2018 and 1 July 2018.

261 The Panel refers here to the projects greater than 150 MW.

- Stockyard Hill (532 MW) in Victoria
- Barker Inlet Gas Power Station (210 MW) in South Australia.

Commissioned generation: Between 19 May 2017 and 1 July 2018[262], 1,178 MW of new generation was commissioned. This is compared to 441 MW in 2016/17, 109 MW of generation commissioned in 2015/16, and 1,074 MW of generation commissioned in 2014/15.

Notably, out of 1,178 MW commissioned generation in 2017/18, 1,174 MW are solar and wind projects.

In terms of capacity, the main generation projects commissioned in 2017/18 were:[263]

- Clare Solar Farm (150 MW) in Queensland
- Sun Metals Solar Farm (125 MW) in Queensland
- Silverton Wind Farm (198.94 MW) in New South Wales
- Sapphire Wind Farm Phase 1 and 2 (270 MW) in New South Wales
- Hornsdale Wind Farm Stage 2 (102 MW) in South Australia
- Hornsdale Wind Farm Stage 3 (109 MW) in South Australia
- Hornsdale Power Reserve (100 MW) in South Australia.

More information on new and committed generation projects is available in appendix A.

3.2.3 Generation withdrawals

In 2017/18, there was no generation formally withdrawn.

Hydro Tasmania had stopped operating the Tamar Valley Power Station (208 MW) in May 2017. However, ahead of the 2017/18 summer the full capacity of the generator was returned to service.[264] The generator was then mothballed from April 2018. Hydro Tasmania has stated that this power station will be available to return to operation with less than three months' notice.[265]

Another generator that was mothballed and then returned to service was the Smithfield gas-fired power station (171 MW) in New South Wales. This generator was closed in July 2017, but was brought back to service in December 2017.[266]

It has been announced that 2,314 MW of generation will be withdrawn from the NEM by mid-2022. All the generators announced for withdrawal are coal or gas fired thermal, synchronous generators. The generators announced for withdrawal are:[267]

262 The analysis provided is not strictly aligned with the 2017/18 financial year. This is because data was derived from the AEMO's regional generation information pages that were published as at 19 May 2017, 22 December 2017, 16 March 2018 and 1 July 2018.

263 The Panel refers here to the projects greater than 100 MW.

264 AEMO, *Summer operations 2017/18*, final report, November 2017, p. 14.

265 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 49.

266 AEMO, *Generation_Information_NSW_March_2018*, 16 March 2018. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

267 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 49.

- AGL intends to retire Torrens A Power Station (480 MW) in South Australia, with two units withdrawing in 2019, and the other two in 2020 and 2021. The station will be partially replaced by the Barker Inlet Power Station (210 MW), which will start operation in 2019.
- AGL has announced its intention to withdraw the Liddell Power Station (1,800 MW summer capacity) in New South Wales in 2022.
- Stanwell has announced its intention to withdraw the Mackay Power Station (34 MW) in Queensland in 2021.

The projected impact of these retirements on the reliability of the NEM is discussed in chapter 4.

More information on generation withdrawals is available in appendix A.

The withdrawal of large, typically synchronous coal and gas-fired generation also has implications for system security, including reducing the amount of inertia and system strength, potentially contributing to a reduction in the availability of ancillary services in the NEM. These ancillary services include Frequency Control Ancillary Services (FCAS)[268] and System Restart Ancillary Services (SRAS).[269] The retirement of synchronous generators in certain states has also created a need for additional reactive power support to maintain transmission system voltages within operational limits. These system security implications are discussed in chapter 5.

In November 2018, the AEMC made a final rule that requires large electricity generators to provide at least three years' notice to the market before closing. The rule requires AEMO to maintain an up-to-date list of expected closure dates for generating units on its website. In March 2019, AEMO published for the first time the expected closure years for scheduled and semi-scheduled generators in the NEM. As of March 2019, there were 20 generators on the list with the closure years starting from 2028 to 2049. According to AEMO, this data is expected to be updated fortnightly.[270]

Ageing generation

A large amount of existing coal-fired generation capacity will reach the end of its expected operating life over the coming two decades. Figure 3.16 shows the projected retirements of coal-fired generators across the NEM. It is forecast that around 15 GW[271] of generation will reach its end of technical life by 2040 and retire.[272]

268 FCAS services are used to raise system frequency if it has fallen (by increasing generation or reducing load) and to lower system frequency if it has risen (by decreasing generation or increasing load). FCAS are intended to work together to maintain a steady frequency during normal operation, and to stabilise and restore the frequency by reacting quickly and smoothly to contingency events that cause frequency deviations.

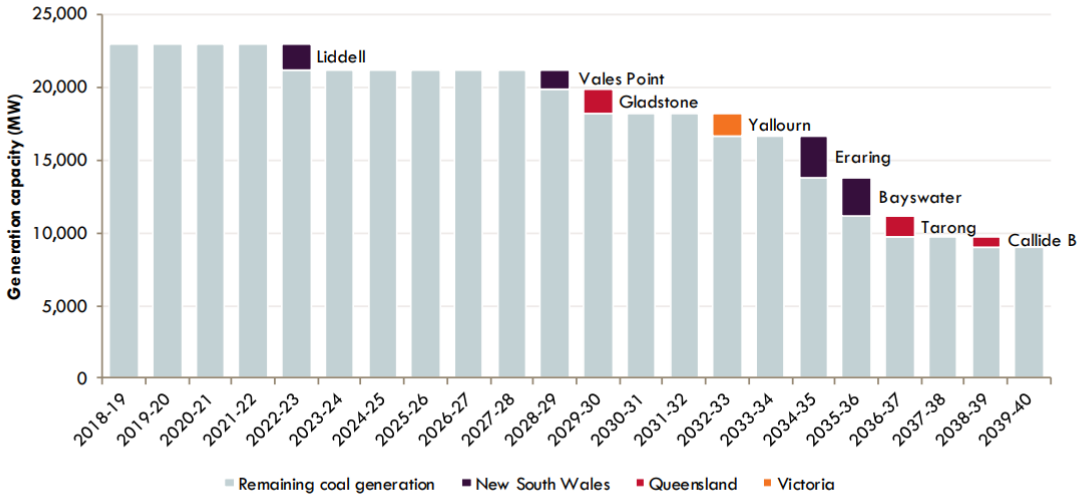
269 SRAS are procured by AEMO in order to mitigate the impact of a major supply disruption. SRAS provides the capability to restart the power system from a 'black system' condition, where there is a complete loss of power supply in a given area.

270 For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

271 14 GW of coal fired and about 1 GW of GPG.

272 AEMO, *Integrated system plan*, July 2018, p. 21.

Figure 3.16: NEM coal-fired generation fleet operating life to 2040



Source: AEMO, *Integrated System Plan*, July 2018.
Note: For black coal-fired power stations, technical life is assumed to be 50 years in most cases. For Victorian brown coal-fired power stations, the retirement dates broadly align with the 17-year mine rehabilitation guarantee secured by the Victorian Government in June 2018.

The existing thermal generation fleet is ageing, and analysis of historical forced generation outages has highlighted that this may be linked to a gradual deterioration in plant reliability in aggregate, most evident over the past three years.[273]

Outages, either forced or unforced (due to maintenance), of these ageing generators can become more common, particularly for those generators that are past their technical operating lifespan. This may be exacerbated if operators of generators nearing the end of technical life refrain from maintaining or investing in those generators.

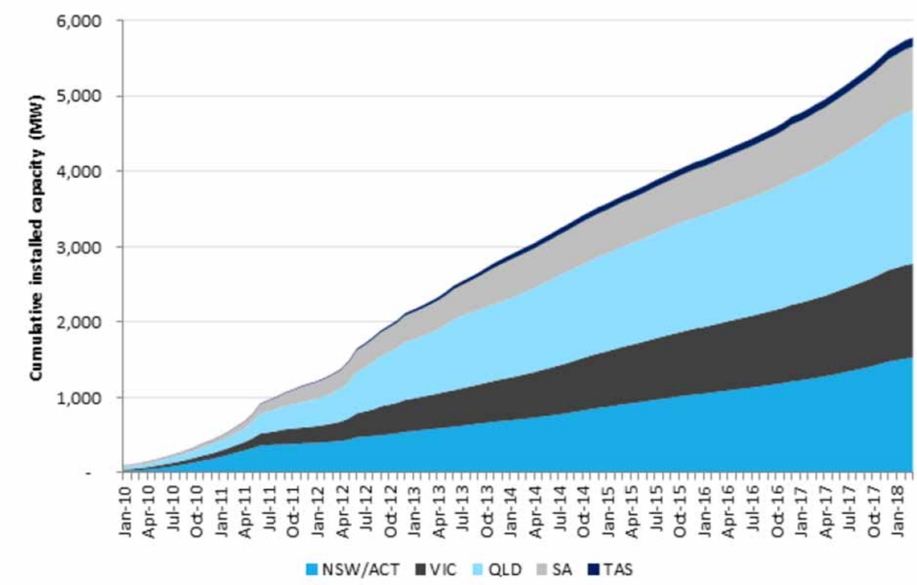
Furthermore, many of the thermal generators in the NEM that are nearing the end of their technical life have high capacities. Any increase in the probability of these large generators unexpectedly tripping can also markedly increase the degree of risk faced by the system, both in terms of reliability and security of electricity supply. Outages of thermal generators are one of the key contributing drivers of the heightened risk of unserved energy exceeding the reliability standard in the short term. This is particularly the case during periods of high demand. Other drivers of the heightened risk of unserved energy are an increase in expected peak demands across regions and interregional constraints.[274] An analysis of outage rates and commentary on associated reliability impacts is provided in more detail in chapter 4.

273 *AEMO, 2018 Electricity statement of opportunities*, August 2018, p. 48.
274 AEMO, *2018 Electricity statement of opportunities*, August 2018, p.54.

3.2.4 Increased rooftop PV and distributed storage

The 2017/18 financial year was the highest period of growth for rooftop PV since installations were first recorded. In 2017/18, approximately 1,300 MW of new rooftop PV capacity was installed, bringing the total rooftop PV capacity in the NEM to about 6,500 MW.[275] This represents around 12 per cent of the total generation capacity in the NEM.[276] Figure 3.17 demonstrates the uptake of small-scale solar PV in the NEM between January 2010 and January 2018.

Figure 3.17: Installed small-scale solar PV capacity in the NEM regions



Source: AEMC adaptation of postcode data from the Australian PV institute.

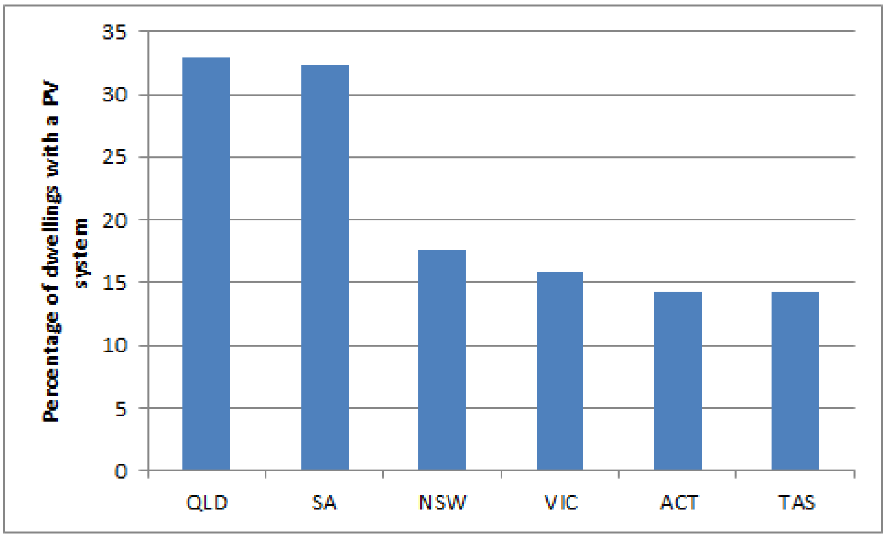
Further, Figure 3.18 shows the estimated percentage of dwellings with a PV system by state.

- In Queensland and South Australia 32 per cent of households have a rooftop PV system.
- In other states there are roughly 15 per cent of dwellings with a rooftop PV system.

275 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 27.

276 AEMO, *National Electricity Market*, viewed on 10 September 2018, at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM

Figure 3.18: Percentage of dwellings with a PV system by state



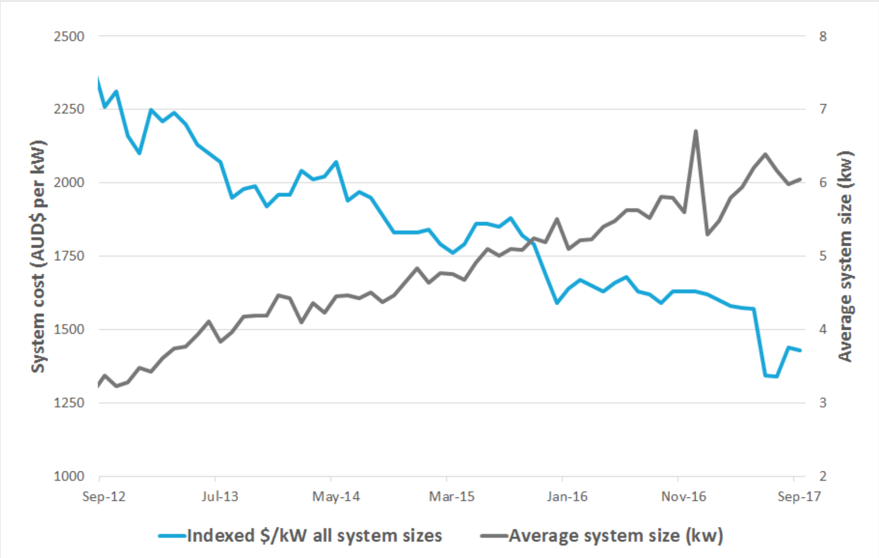
Source: Australian PV Institute, accessed on 6 February 2019, at: http://pv-map.apvi.org.au/historical#4/-26.67/134.12

Note: The percentage of dwellings with a PV system is estimated by comparing the total number of freestanding and semi-detached dwellings with the number of residential PV systems installed in each area (estimated by counting the number of PV systems smaller than 10 kW).

The increase in volumes and sizing of distributed solar PV has been in part driven by the general decrease in unit costs. Costs per kW have decreased in recent years which has led to a notable increase in the size of systems installed over the same period (see Figure 3.19). Further, the Alternative Technology Association stated that, per panel, large solar PV systems are becoming increasingly cheaper than small ones. Since August 2012, larger residential systems have halved in price, while smaller ones have only decreased by a quarter.[277]

277 Alternative Technology Association, *Solar sizing: Bigger is Better*, Discussion paper, Melbourne, May 2017.

Figure 3.19: Average size of solar system installed compared to cost ($/kW)

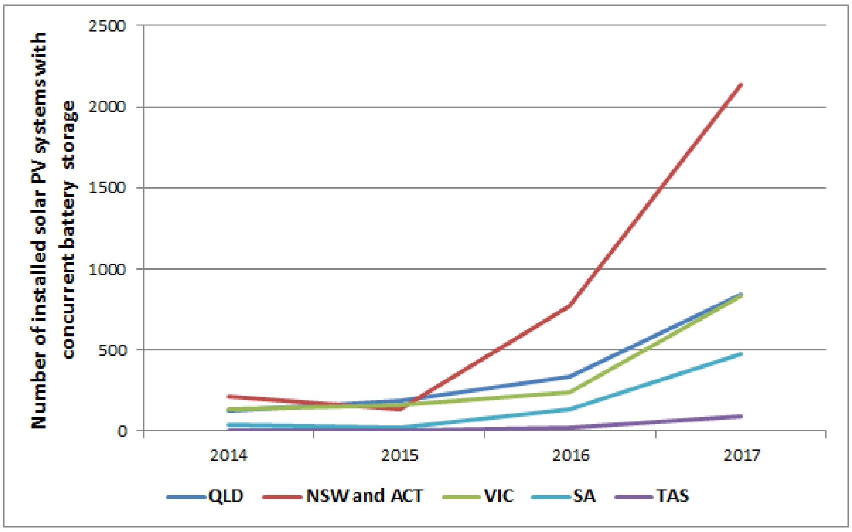


Source: AEMC, *2018 Retail Energy Competition Review*, June 2018.

Another emerging trend is the installation of combined small scale solar PV and battery systems. According to the Clean Energy Regulator (CER), as at 31 July 2018, the number of concurrently installed small-scale solar PV and battery systems reached 9,388 installations in the NEM.[278] Figure 3.20 shows the uptake of concurrent small-scale solar PV and battery systems over the last four years by state.

278 Notably, these figures only relate to instances where solar PV and batteries were installed together, and are not exhaustive, as submitting the data to the CER was voluntary.

Figure 3.20: Numbers of concurrent solar PV and battery installations by state



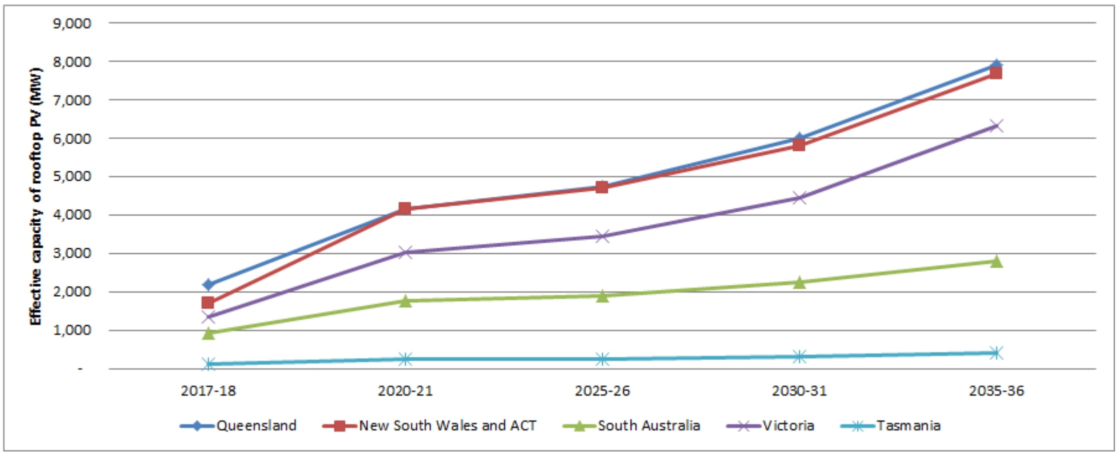
Source: AEMC analysis of CER data, *Postcode data for small-scale installations,* accessed on 10 September 2018, at: http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

Forecast uptake

Figure 3.21 shows AEMO's forecasts of projected uptake of rooftop PV. AEMO is forecasting strong growth in rooftop PV in all NEM regions, except Tasmania.[279] Queensland and New South Wales are forecast to experience the fastest rate of uptake. The total installed capacity of rooftop PV in 2035/36 is projected to be over 25 GW. To put this in perspective, 25 GW is equivalent to around 45 per cent of the total installed generation capacity currently in the NEM.

279 The number of rooftop PV installations is forecast to grow in Tasmania, but at a much slower rate relative to the other regions.

Figure 3.21: Installed rooftop PV capacity forecasts



Source: AEMO.

Figure 3.22 shows AEMO's forecasts of projected uptake of concurrent PV and storage systems. AEMO is forecasting strong growth in integrated PV and storage systems in all NEM regions, except Tasmania.[280] New South Wales is forecast to experience the fastest rate of uptake.[281] AEMO forecasts that in 20 years, 15 per cent of all residential rooftop PV installations will be integrated with batteries, with behind-the-meter battery systems constituting 2.6 GW of storage capacity.[282] Interestingly, this is less than half the level of uptake projected by AEMO last year.[283] This is mainly due to lower forecast retail electricity prices leading to an increased payback period.[284]

280 The number of integrated PV and storage systems is forecast to grow in Tasmania, but at a much slower rate relative to the other regions.

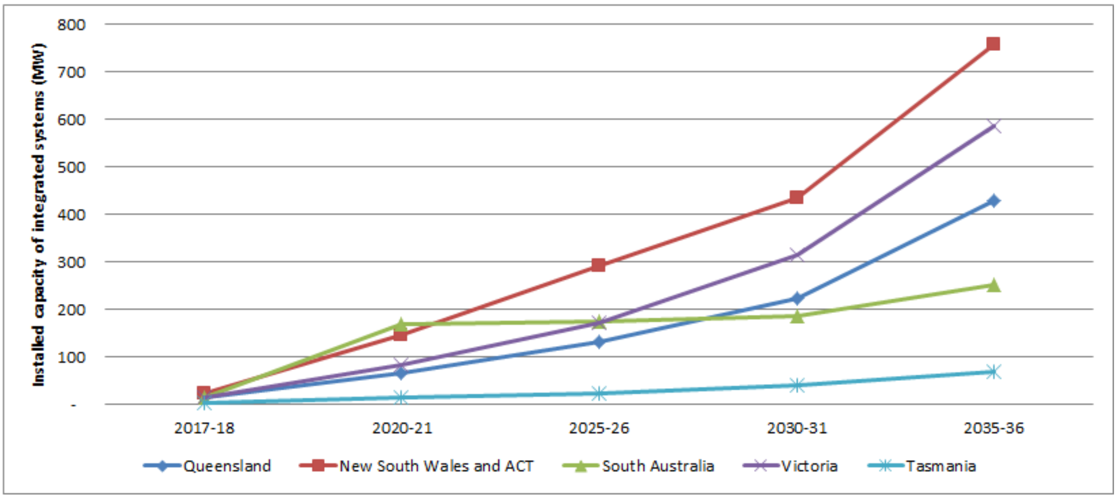
281 The model used by AEMO for forecast the uptake of integrated systems does not consider the retrofitting of storage to existing PV systems. As a result, regions with current higher penetrations of PV systems experience apparent lower projections of uptake of integrated systems as the number of potential sites is diminished. In practice, actual values in these regions may be higher, to account for any retrofitting of storage that may occur.

282 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 28.

283 While the overall NEM battery uptake forecast this year is lower, South Australia has a higher battery forecast over the next five years. This is due to the state government policy supporting the installation of 40,000 residential batteries.

284 AEMO, *2018 Electricity statement of opportunities*, August 2018, p. 28.

Figure 3.22: **Integrated PV and storage systems capacity forecast**



Source: AEMO.

3.2.5 Demand response

Demand response is consumers, specifically loads, changing their level of consumption in response to short term signals to do so. These signals could be price signals from the wholesale market, or could be instructions coming from the market operator, a retailer or a third party.

There are different types of demand response: wholesale, emergency, network and ancillary services, as shown in the table below. While the equipment that provides these different types of demand response is often the same, the services provided are distinct.

Table 3.1: **Four types of demand response in the NEM**

TYPE	DESCRIPTION	CURRENT STATUS
Wholesale demand response	Demand response used to change the quantity of electricity bought in the wholesale market, which could be used to manage spot price exposure, or to help market participants manage their positions in the contract market.	Due to the lack of transparency around how much wholesale demand response is currently being utilised, it is difficult to draw firm conclusions about how much demand response is occurring in the NEM, or whether this level is efficient. Wholesale demand response is the subject of the AEMC's *Wholesale demand response mechanism* rule change process.[1]
Ancillary service	Demand response employed for providing ancillary	Large energy users have used demand response to provide FCAS. Market ancillary

TYPE	DESCRIPTION	CURRENT STATUS
demand response	services. For example, responding quickly to brief, unexpected imbalances in supply and demand by participating in the frequency control ancillary service (FCAS) markets.	service providers (MASPs) can offer customers' loads into FCAS markets. Currently, there are two MASPs using demand response to provide FCAS: EnerNOC and HydroTasmania. The AEMC has made a number of recommendations and changes to the NER to facilitate these kinds of services.
Emergency demand response	Demand response employed by the system operator during supply emergencies, with the service being centrally dispatched or controlled to avoid involuntary load shedding. This is generally provided by out-of-market reserves.	Demand response can - and currently is - participating in the RERT. The AEMC is currently considering ways to enhance the RERT through its consideration of AEMO's rule change request.[2]
Network demand response	Demand response employed to help a network business to provide network services to consumers.	The existing regulatory framework provides a number of incentives and obligations for non-network options (including demand response) to be adopted by a network service provider where it is efficient to do so. For example, the Demand Management Incentive Scheme (DMIS) provides distribution network service providers (DNSPs) with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management and the Demand Management Incentive Allowance (DMIA) mechanism provides an allowance to DNSPs to undertake innovative projects related to demand management. The ACCC recommended in its *Retail Electricity Pricing Inquiry* that both the DMIS and DMIA be extended to also apply to transmission network service providers (TNSPs).[3]

Source: AEMC, *Wholesale demand response mechanisms*, consultation paper, November 2018, p. 4-6.

Note: 1 - For more information on the AEMC's *Wholesale demand response mechanism* rule change process, see: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

Note: 2 - For more information on the AEMC's *Enhancement to the RERT* rule change process, see: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

Note: 3 - ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail electricity pricing inquiry,* final report, June 2018, available at: https://www.accc.gov.au/publications/restoring-electricity-affordability-australias-competitive-advantage

Wholesale demand response refers to the demand response used to change the quantity of electricity bought in the wholesale market, which could be used to manage spot price exposure, or to help market participants manage their positions in the contract market.[285] In other words, by responding to wholesale prices, the load is able to make the trade-off between the costs of consuming electricity and the opportunity cost of reducing its electricity consumption.

The majority of consumers in the NEM are not directly exposed to the wholesale spot price[286], instead purchasing electricity via retail tariffs offered by retailers. Such consumers have no direct incentive to respond to wholesale prices.[287] Consumers that are not exposed to the wholesale price can still provide wholesale demand response, but the signal which consumers respond to must come from a third party; for example, a retailer or a demand response aggregator.

Under the current regulatory frameworks, wholesale demand response can be provided in a number of ways, including:

- A retailer may procure demand response services from loads to help it to manage wholesale market risk.
- A customer may opt to take a retail contract with some form of spot price pass through arrangement. This does not necessarily result in wholesale demand response. However, it may provide the load with an incentive to alter consumption in response to wholesale prices.
- A customer could opt to purchase electricity directly from the wholesale market (that is, without going through a retailer). As above, this would not necessarily result in wholesale demand response[288], but the customer may receive economic benefits by responding to the wholesale electricity price and may therefore alter consumption in response to the wholesale price.

The actual extent of demand response in the NEM is not readily apparent. As much of the demand response in the NEM arises from bilateral contracts or a reaction to wholesale prices (as opposed to being scheduled in the wholesale market), it is difficult to quantify exactly how much demand response occurs. Additionally, the amount of wholesale demand response is not static. It depends on the operating state and preferences of loads on a real time basis.

Figure 3.23 shows the level of demand side response that AEMO considered to be currently available in the NEM at the time of publishing its *2018 Electricity Statement of Opportunities*. These estimates capture direct response by industrial users, and consumer response through programs run by retailers, aggregators, or network service providers. The figure below

285 AEMC, *Wholesale demand response mechanisms*, consultation paper, November 2018, p. ii.

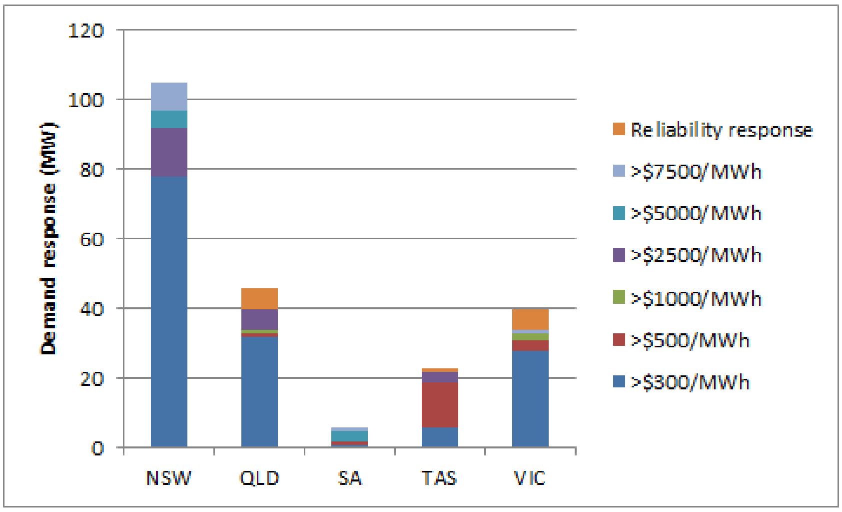
286 Since the start of the market, loads have not been required to schedule bids. Loads have the option of being scheduled in central dispatch; however to date, most loads have elected not to be scheduled, which indicates they do not see a business advantage in doing so. The Commission has recently considered requiring loads to bid into the market, but decided that the upfront costs that would be imposed on loads would outweigh any benefits of doing so. For more information, see: http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

287 Electricity retailers use contracts and other products to manage variable wholesale prices and underwrite fixed retail contracts.

288 To purchase electricity directly from the wholesale market, a customer would need to register with AEMO as a Market Customer. Such customers are likely to have hedging contracts that would reduce the incentive to demand respond, depending on the costs of the contracts.

considers the amount of demand response that would be expected at certain wholesale prices. For example, AEMO expects there to be approximately 78 MW of demand response in NSW when the price reaches $300/MWh.

Figure 3.23: Amount of demand response in the NEM, per region



Source: AEMO, *Demand side participation page.*
Note: For the purposes of this data, AEMO defines a reliability response as the expected demand response following the declaration of actual LOR2 or LOR3 condition. The capacities listed exclude any demand response procured through the RERT process, including the joint demand response program by ARENA and AEMO.

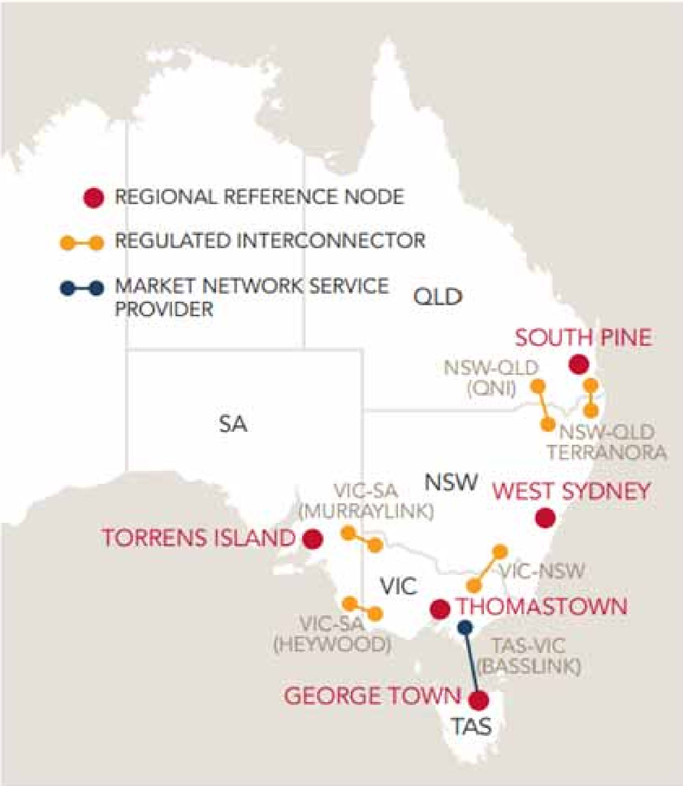
For more information on the work underway on wholesale demand response, see chapter 4.

3.3 Bulk transfer capability, upgrades and performance

The interconnected transmission network in the national electricity market is important for facilitating a reliable supply of electricity to consumers and to support the NEM wholesale market by allowing electricity to be bought and sold across regions.[289] The physical location of each interconnector in the NEM is shown in Figure 3.24.

289 For example, if prices are very low in one region and high in an adjacent region, electricity can be sent from the first to the second region across an interconnector up to the maximum technical capacity of the interconnector.

Figure 3.24: Interconnectors in the NEM



Source: AEMO, *An introduction to Australia's National Electricity Market*, p. 15.

Historically, the boundaries between the regions of the NEM (which generally correspond to state borders) have been the points at which flows of electricity may be constrained, due to the physical structure of the power system. The degree to which these cross boundary flows are constrained can have implications for wholesale prices in each region, particularly when high prices due to a tight supply demand balance in a region can be reduced by importing power from another region.

This section discusses some of the work currently being undertaken that considers the current performance as well as future development of interconnection in the NEM. In particular, it considers:

- the performance of interconnectors
- the modelled impacts of increased inter-regional transfer capacity in AEMO's *Integrated System Plan (ISP)*.[290]

Some key points to note include:

290 The ISP is a cost-based engineering optimisation plan by AEMO that forecasts the overall transmission system requirements for the NEM over the next 20 years.

- Some significant changes occurred in the direction of interconnector flows. Notably, Victoria's exports decreased significantly in comparison with the last three years, while South Australia became a net exporter for the first time since 2008/09.[291]
- These general trends are relevant to the performance of specific interconnectors. Particularly, these trends impact flow rates between regions, frequency and extent of flows binding.
- Currently, there is a lot of focus on inter-regional congestion and interconnector capability. In July 2018, AEMO published its inaugural ISP, which identifies a pathway for transmission and interconnector investments.[292] To make the ISP actionable, a comprehensive reform package was developed by the Energy Security Board (ESB) and the AEMC.[293]

3.3.1 Interconnector flows

Congestion

Limits exist on the transmission network's ability to carry electricity. If the limits on a particular part of the network are reached so that the power flows are constrained to levels less than desired, then there is said to be congestion on that part of the network.[294]

Congestion is a normal feature of power systems. It occurs because there are physical limits needed to maintain the power system in a secure operating state.[295]

Importantly, congestion on the transmission network can be influenced by events occurring far away from the physical line that is constrained. Consequently, flows across the interconnectors and the capacity for inter-regional trade in the NEM is not only influenced by the limits of the physical assets that cross region boundaries, but also by constraints occurring in parts of the network further removed from the actual interconnector infrastructure.

These limits are applied in the form of 'constraint equations' in the dispatch process, that is operationalised through the National Electricity Market Dispatch Engine (NEMDE).[296]

In theory, congestion may be eliminated if sufficient money was spent on expanding, or upgrading transmission network infrastructure. However, the cost of doing this may outweigh

291 AER, *Wholesale statistics,* accessed at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-interregional-trade-as-a-percentage-of-regional-energy-consumption

292 For more information, see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf

293 For more information on the comprehensive reform package, see: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

294 AEMC, *Last Resort Planning Power 2018*, February 2019, p. 13.

295 During normal operation of the power system, transfer across an interconnector will ultimately be limited by constraints within the dispatch process. However, the power system operates in a dynamic environment, and it is possible for secure technical limits to be exceeded on interconnectors for durations shorter than 30 minutes (clause 4.2.6(b)(1)). During 2017/18, the Panel has not been advised of any power system incidents involving interconnectors, where the power system was above its secure limit for longer than 30 minutes.

296 AEMO operates the NEMDE, a computer program designed to optimise dispatch decisions. NEMDE dispatches generation on a five-minute interval basis, taking into account a variety of parameters and variables. Among these are generator offers, but also the thermal, voltage and stability limits of the network. Within these parameters, NEMDE calculates the optimal market solution for dispatch. That is, the lowest cost solution for dispatch of generation in order to meet demand. More information is available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability%20/Dispatch-information

the costs incurred from the congestion itself. In this sense, congestion occurs not only because of the network's physical limitations, but also because of economic considerations of net costs and benefits. In other words, some level of congestion is likely to be economically efficient.[297]

For its *Coordination of generation and transmission investment review* the AEMC engaged Ernst & Young (EY) to assess patterns and costs of congestion in the NEM. The EY work demonstrated that there are limited amounts of congestion in the NEM at the moment. To the extent that congestion occurs, it is largely limited to between regions (i.e. inter-regional congestion).[298]

However, there is over 49,000 MW of proposed new generation which has expressed interest in connecting across the NEM.[299] Private sector investors are planning generation where transmission has limited or no capacity to accommodate it.[300] For example, in New South Wales, as at November 2018 more than 20,000 MW of large-scale projects were progressing through the New South Wales planning system. The New South Wales Government's T*ransmission Infrastructure Strategy* published in November 2018 stated that 'for every 20 projects looking to connect to the grid only one can. Companies simply will not invest if they can't connect.'[301]

Interregional flows

Figure 3.25 shows annual interregional trade as a percentage of regional energy consumption. Some notable changes occurred over 2017/18:

- Victoria's exports decreased significantly in comparison with the last three years.
- Flows from Queensland into New South Wales (and then through to Victoria) increased as Queensland black coal generators increased output in 2017.[302]
- Despite a strong trend of South Australia importing an increasing amount of energy over the last decade, in 2017/18 South Australia became a net exporter for the first time since 2008/09.

297 AEMC, *Last Resort Planning Power 2018*, February 2019, p. 13.

298 For more information, see: AEMC, *Coordination of generation and transmission investment,* discussion paper, 13 April 2018. This analysis is also consistent with AEMO's analysis of congestion for the ISP.

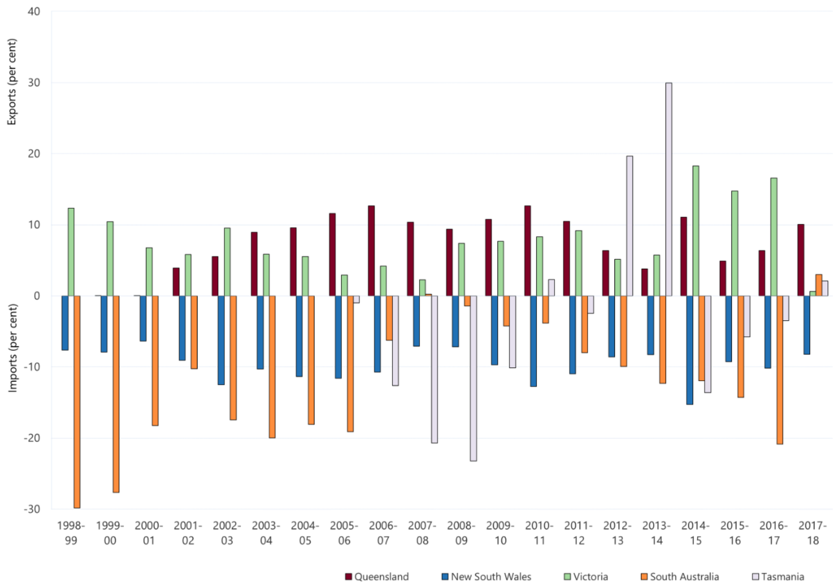
299 AEMO, *Generation information page*, accessed on 11 September 2018, at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

300 AEMC, *Coordination of generation and transmission investment*, final report, December 2018, p. 74.

301 NSW Department of Planning and Environment, *NSW Transmission Infrastructure Strategy: Supporting a modern energy system*, November 2018, p.3.

302 AER, *AER electricity wholesale performance monitoring. Hazelwood advice*, March 2018, p. 2.

Figure 3.25: **Annual interregional trade as a percentage of regional energy consumption**



Source: AER, *Wholesale statistics*, accessed at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-interregional-trade-as-a-percentage-of-regional-energy-consumption

Individual interconnector flow patterns

Six interconnectors transport electricity between adjacent NEM regions. The Queensland-New South Wales (QNI) interconnector, Victoria-New South Wales (VNI) interconnector and Heywood interconnector are high voltage alternating current links while Terranora, Murraylink and Basslink are high voltage direct current links.

The Panel has included some analysis below on the performance of some of these interconnectors, focussing on the QNI, VNI and Heywood interconnectors over 2017/18. These specific interconnectors were selected as they demonstrate changing patterns of interregional flows.

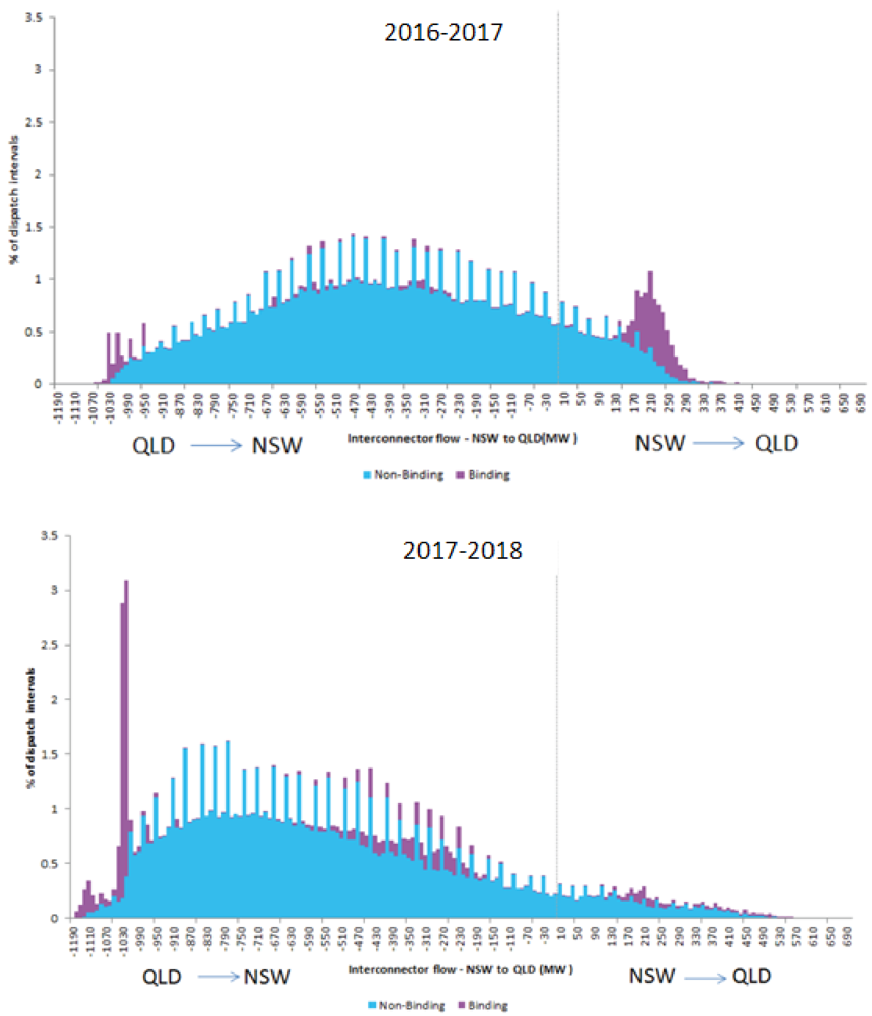
QNI

QNI is a 330 kV alternating current double circuit interconnection that runs between Bulli Creek in Queensland and Dumaresq in New South Wales.[303] QNI currently has a nominal capacity of 300-600 MW from New South Wales to Queensland and 1,050-1,078 MW from Queensland to New South Wales.

Figure 3.26 indicates a general trend of increasing flows from Queensland to New South Wales across QNI from 2016/17 to 2017/18.

303 AEMO, *Interconnector capabilities*, November 2017, p. 4.

Figure 3.26: Inter-regional flows via QNI



Source: AEMC, *Last Resort Planning Power 2018*, February 2019.

Regarding constraints on the interconnectors:

- New South Wales imports via QNI generally bound more often at higher flow levels in 2017/18 than in 2016/17, and also bound more frequently near the nominal capacity limit of 1,078 MW.
- While in 2016/17 New South Wales imports frequently bound below 300 MW, in 2017/18 they bound much less frequently in this direction.[304]

To improve flows on QNI, several options were proposed in TransGrid and Powerlink's Regulatory Investment Test for Transmission (RIT-T) *Project Specification Consultation Report*

304 AEMC, *Last resort planning power 2018*, February 2019, p. 34.

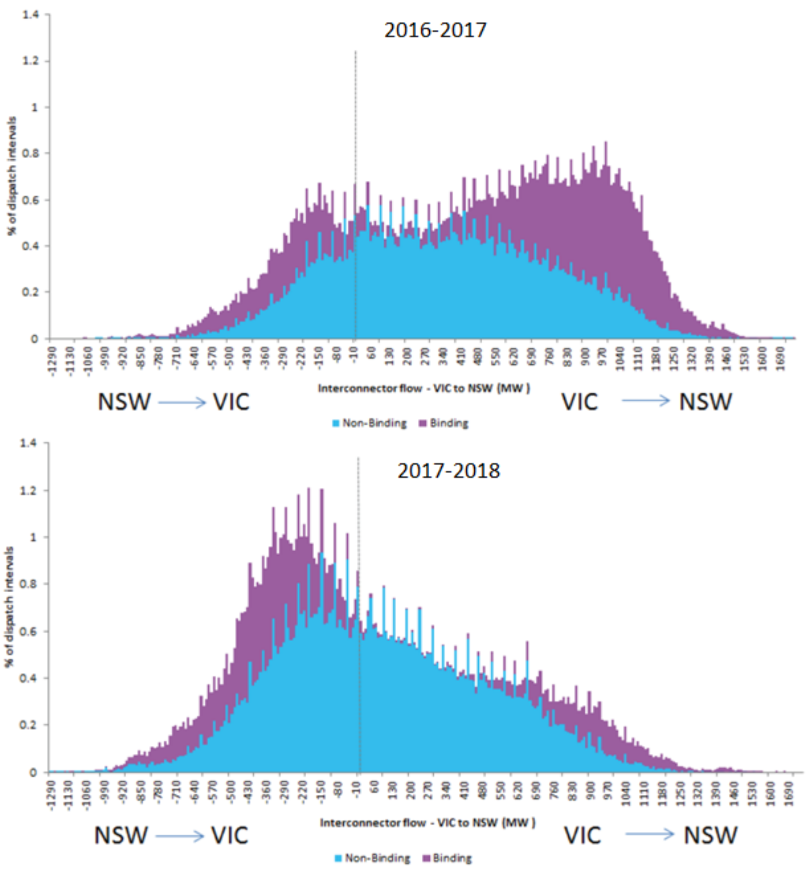
(PSCR). Uprating the Liddell to Tamworth lines, installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks are also AEMO ISP Group 1 projects.[305]

VNI

VNI is an alternating current interconnector between northern Victoria with southern New South Wales. VNI currently has a nominal capacity of 700-1,600 MW from Victoria to New South Wales and 400-1,350 MW from New South Wales to Victoria.[306]

Figure 3.27 indicates a trend of increasing flows from New South Wales to Victoria.

Figure 3.27: Inter-regional flows via VNI



Source: AEMC, *Last Resort Planning Power 2018*, February 2019.

Flows from New South Wales to Victoria bound more often at both high and low flow levels in 2017/18 than in 2016/17. Victoria to New South Wales flows bound much less frequently in 2017/18 than in 2016/17 across all flow levels.

305 Ibid, p. 42.

306 AEMO, *Interconnector capabilities*, November 2017, p. 5. The nominal capacity of VNI is highly dependent on the output of the Snowy Hydro Murray generators (for New South Wales to Victoria) and Lower/Upper Tumut generators (for Victoria to New South Wales). VNI can bind in either direction for high demand in New South Wales or Victoria.

Several options proposed in AEMO and TransGrid's RIT-T PSCR could improve flows on VNI. These include the following AEMO ISP Group 1 projects:[307]

- uprating the Canberra-Upper Tumut line
- an additional 500/330 kV transformer(s) at South Morang
- uprating the South Morang-Dederang lines
- a braking resistor, battery storage or a flexible alternating current transmission system device.

Heywood

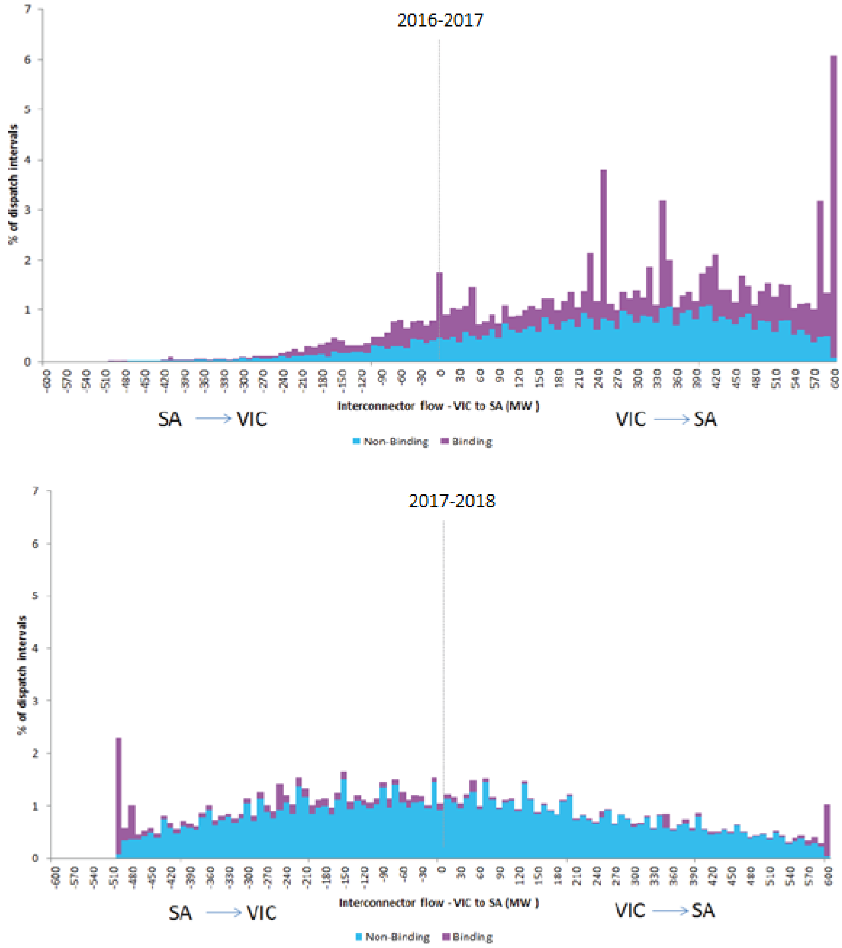
The Heywood interconnector is an alternating current connection between Heywood in Victoria and the south-east of South Australia.[308] ElectraNet has recently carried out upgrades on the Heywood interconnector to increase the interconnector's nominal transfer capacity to 650 MW in either direction of flow.[309] The limits on the Heywood interconnector currently remain below 650 MW in order to manage system security issues, including a potential stability issue at high levels of transfer from Victoria to South Australia.[310]

The Heywood interconnector currently has a nominal capacity of 600 MW from Victoria to South Australia and 500 MW from South Australia to Victoria.[311]

Figure 3.28 indicates a trend of increasing flows from South Australia to Victoria through the Heywood interconnector. In 2016/17, the Heywood interconnector predominantly transmitted energy from Victoria to South Australia, but in 2017/18, energy flowed more equally in both directions.

307 AEMC, *Last resort planning power 2018*, February 2019, p. 69-73.
308 AEMO, *The national electricity market constraint report 2017 electronic material*, June 2017.
309 AEMO, *Interconnector capabilities*, November 2017, p. 6.
310 Ibid.
311 Ibid.

Figure 3.28: Inter-regional flows via the Heywood interconnector



Source: AEMC, *Last Resort Planning Power 2018*, February 2019.

The chart shows that there was a significant overall reduction in occurrences of the Heywood interconnector being bound by constraints in 2017/18.

Several projects being considered by ElectraNet in its *Transmission annual planning report* could address this constraint. None of these projects are AEMO ISP Group 1 projects.[312]

3.3.2 Modelled impacts of increased transfer capacity

Currently, there is a lot of focus on inter-regional congestion and interconnector capability. In July 2018, AEMO published the Integrated System Plan (ISP).[313] The ISP is a cost-based engineering optimisation plan by AEMO that forecasts the overall transmission system requirements for the NEM over the next 20 years.[314] It identifies a potential plan of the

312 AEMC, *Last resort planning power 2018*, February 2019, p. viii.

313 The *2017 National Transmission Network Development Plan* (NTNDP) has been incorporated into the ISP.

transmission investments that will be necessary to support the long term interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures.[315]

Investments identified in the ISP are grouped into three phases.[316] These are discussed below.

The Group 1 investment projects

The Group 1 investment projects are those that AEMO considers should be progressed as soon as possible because they provide immediate benefits. These projects are:

- Increase transfer capacity between Victoria, New South Wales and Queensland:
  - Increase Victorian transfer capacity to New South Wales by 170 MW.
  - Increase Queensland transfer capacity to New South Wales by 190 MW.
  - Increase New South Wales transfer capacity to Queensland by 460 MW.
- Access renewable energy in western and north-western Victoria.
- Remedy system strength in South Australia.

According to AEMO, among the benefits of these investment projects are:[317]

- increasing efficient utilisation of existing and committed resources
- reducing reliance on higher-cost gas thermal generators
- allowing coal-thermal generators to operate within more efficient ranges
- reducing congestion
- diversifying the supply of renewable energy to the market.

The estimated costs of the transmission investments in Group 1 are in the order of $450 million to $650 million.

All Group 1 projects identified by AEMO in the ISP are being progressed by individual TNSPs under current arrangements. The projects are all either: currently the subject of RIT-T assessments; are exempt from a RIT-T assessment; or have been identified as contingent projects by TNSPs.

In its *Coordination of generation and transmission investment* final report, the AEMC recommended the ESB to submit a rule change request to the AEMC to allow the three RIT-T regulatory processes to be undertaken concurrently for the group 1 projects.[318] These processes are the AER's assessment of: any dispute lodged, the preferred option assessment

314 AEMO, *Integrated system plan*, July 2018, p. 3. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

315 ISP modelling incorporates a range of plausible scenarios to identify future demand for power from the system and likely market response. For the latter, the modelling applied technology neutral analysis to identify the required level and likely fuel type of supply investments required to meet future needs. The ISP model uses cost-based economic analysis, and integrates system security and reliability considerations, as well as current Commonwealth and State Government policies.

316 This is based on the timing within which the identified network need is forecast to arise, and the time that may be needed to build infrastucture to address the need.

317 AEMO, *Integrated system plan*, July 2018, p. 8.

318 AEMC, *Coordination of generation and transmission investment,* final report, December 2018, p. iii.

and the contingent project revenue determination. On 24 January 2019, the AEMC published a consultation paper for the *Early implementation of ISP priority projects* rule change request.[319] If implemented, the proposed rule changes would be in place in time to allow the AER to undertake the three processes in parallel, saving six to eight months off the post RIT-T time frames. However, the proposed change for Group 1 projects would also ensure that the checks and balances for a robust process, and assessment that the investments are efficient, remain.

The Group 2 investment projects

The second group of transmission investments outlined by AEMO include developments in the medium term (by the mid-2020s) to:

- increase trade between NEM regions
- provide access to storage
- support the development of renewable energy zones.[320]

The Group 2 investment projects are:

- Establish new transfer capacity between New South Wales and South Australia of 750 MW (RiverLink).
- Increase transfer capacity between Victoria and South Australia by 100 MW.
- Increase transfer capacity from Queensland to New South Wales by a further 378 MW (enhance the existing QNI interconnector).
- Efficiently connect renewable energy sources through maximising the use of the existing network and route selection of the above developments.
- Coordinate distributed energy resources in South Australia.

Some of the Group 2 projects are also being considered and progressed under the current arrangements. These projects are listed in the table below.

Table 3.2: Group 2 projects being considered through the regulatory framework

ISP IDENTIFIED PROJECT	CORRESPONDING PROJECT/RIT-T
RiverLink (new transfer capacity between NSW and SA)	South Australian energy transformation RIT-T.
Medium NSW to QLD upgrade	Expanding NSW-QLD transmission transfer capability RIT-T.
SnowyLink North	TransGrid's Reinforcement of southern network in response to Snowy 2.0 contingent project.

319 For more information, see: https://www.aemc.gov.au/rule-changes/early-implementation-isp-priority-projects

320 The identified renewable energy zones are largely located along the path of proposed new interconnectors. This implies that the future development of REZs will be biased towards generators connecting where there is existing transmission capacity, rather than the development of areas with good renewable resources with new, dedicated transmission infrastructure that is designed to facilitate the connection of new generation.

Source: SA Energy Transformation RIT-T: https://www.electranet.com.au/projects/south-australian-energy-transformation/; Expanding NSW-QLD transmission transfer capability RIT-T: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/QNI%20PSCR%20November%202018.pdf; Transgrid re-enforcement of southern network: AER, *TransGrid transmission determination 2018 to 2023*, final decision, Attachment 6 – Capital expenditure, May 2018.

The New South Wales Government has stated that it will provide a funding guarantee that will allow TransGrid to bring forward preliminary planning work on ISP's Group 2 projects,[321] including the best placement of line routes, geo-technical studies and environmental, heritage and biodiversity assessments for the priority transmission infrastructure projects.[322] Further, the South Australian government stated that direct assistance of $4 million will be provided in 2018/19 to enable transmission network operators to commence early works to support delivery of further interconnection between the eastern states and South Australia. The government will also provide a financial guarantee of up to a further $10 million for this purpose.[323]

The Group 3 investment projects

The third group of transmission investment identified by AEMO in the ISP is focused on the 2030s and is proposed to increase inter-regional and intra-regional transfer capacity across the NEM. AEMO noted in the ISP that there is ''time to consult on, refine and finalise proposed initiatives in Group 3, including the selection of preferred [renewable energy zones] and their timing'' along with the timing of transmission development.[324]

On 21 December 2018, the AEMC published the final report of its *Coordination of generation and transmission investmen*t review. This report recommends a comprehensive reform package that better coordinates investment in renewable generation and transmission infrastructure, facilitating transmission and generation in the right place at the right time at an efficient cost. The AEMC recommends that the reforms be implemented in stages, to enable delivery of the 2018 ISP in the timeframes identified by AEMO. The final report includes an implementation work plan, with the final stage of reforms completed in 2023. The AEMC's recommendations are discussed in more detail in chapter 4.

3.3.3 Network losses

When transferring power through a transmission network, some of the power is lost as heat energy. These losses increase as more generation connects in locations that are distant from load centres, as the power produced by the generation has to travel further to the load centre. Losses are also impacted by changes in power system flows, for example where generation retires in a region and requires more power is imported from other regions.

It is necessary to account for these losses when operating the power system and the market.

In the NEM, this is done by representing these losses with Marginal Loss Factors (MLFs), which are calculated and applied by AEMO annualy to the processes of generation dispatch

321 In relation to Snowy Hydro transmission, the funding guarantee is contingent on Snowy 2.0 proceeding.

322 Department of Planning and Environment, *NSW transmission infrastructure strategy*, November 2018, p. 10.

323 SA State Budget 2018/19, accessed on 15 November 2018 at: https://statebudget.sa.gov.au/#Lower_Costs

324 AEMO, *Integrated system plan*, July 2018, p. 89.

and wholesale market revenue settlement. In effect, these MLFs adjust dispatch and settlement payments to generators to reflect the extent of their marginal energy transfer losses.[325]

MLFs are used to adjust the price of electricity in a NEM region, relative to the regional reference node[326], in a calculation that aims to recognise the difference between a generator's output and the energy that is actually delivered to consumers.[327] Generally speaking, generators with higher MLF values (that is a value that is close to one, or greater than one) will be dispatched first and will receive a settlement payment for energy that is closer to the regional reference price. An MLF less than one will mean that a generator is less likely to be dispatched and will also receive less than the regional reference price. Generators therefore always prefer an MLF that is closer to, or greater than, one.

A single MLF is calculated by AEMO and then applied to each transmission connected generator and load, for a period of one year. Historically, MLFs did not change markedly from year to year. However, various factors, including recent changes in the power system, have meant that this process has resulted in significant year to year changes in some MLFs in some parts of the power system, with some generators seeing marked decreases in their MLFs.

Investors in new generation are concerned about the effect of decreased MLFs on their potential returns, and the uncertainty of how MLFs can vary from one year to the next. This is particularly the case for generators connecting far away from load centres, such as remotely connected renewable generators. Generators in locations that are strongly connected to major load centres have MLFs that are less likely to change over time.[328] These changes in MLFs can therefore have negative impacts for investment in new generation.

The Panel has examined some of the changes in MLFs that have occurred across the NEM regions in the last three years. Over this period, a significant decrease in MLFs was observed in north and central Queensland. In New South Wales, however, there was an increase in MLFs in the south of the state and decrease in the north. In other NEM regions, changes in MLFs were not as significant. Figure 3.29 shows the changes to MLFs at Queensland and New South Wales connection points from 2016/17 to 2018/2019 compared to the previous years.

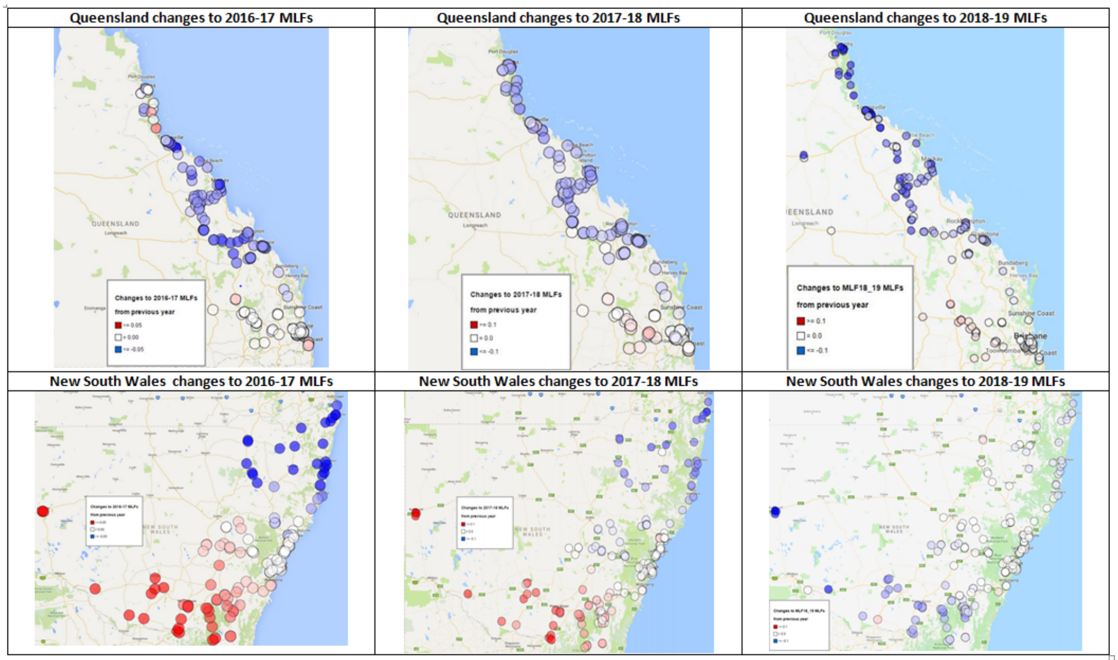
325 For more information on the treatment of MLFs in the NEM, see: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2016/Treatment_of_Loss_Factors_in_the_NEM.pdf

326 The reference point (or designated reference node) for setting a region's wholesale electricity price.

327 AEMO, *Integrated system plan*, July 2018, p. 53.

328 Ibid.

Figure 3.29: Changes to MLFs in Queensland and New South Wales between 2016/17 and 2018/19



Source: AEMO's *Regions and Marginal Loss Factors* reports. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

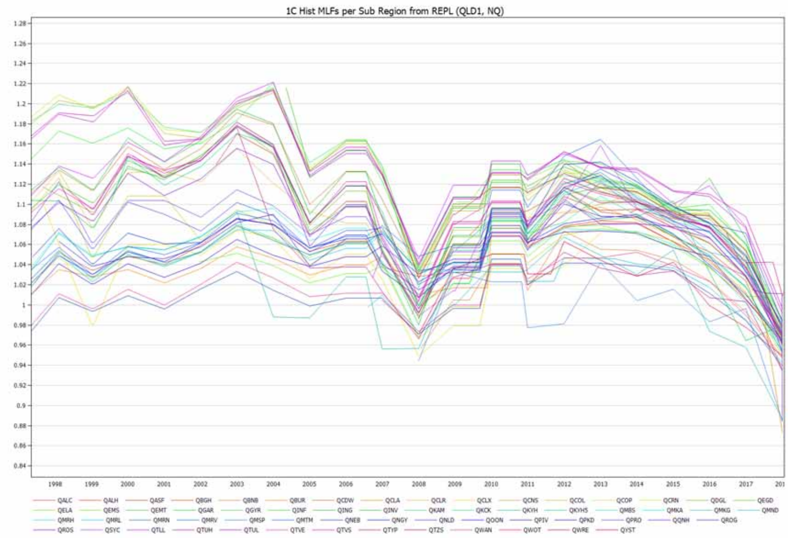
The general trend of a reduction in MLFs at connection points in central and northern Queensland could be explained by an increase in power flow from northern and central Queensland toward the regional reference node, located in the south of the region. This change in flows is due to changes in the generation mix and in demand patterns. In particular, the retirement of large thermal units in the south of the NEM, coupled with increased entry of renewable generation and reduced demand in Queensland driven by the high penetration level of rooftop solar PV, have resulted in changes to flows and degraded the MLFs for several Queensland generators.[329]

Figure 3.30 demonstrates MLFs change in north Queensland. It shows over the last 20 years MLFs in North Queensland decreased significantly. Further, the decrease of MLFs in this region has notably accelerated in the recent years. According to AEMO, from 2017/18 to 2018/19, the planned connection of over 1,200 MW of new solar generation in north and central Queensland has led to MLFs falling by up to 12 per cent.[330]

329 AEMO's *Regions and Marginal Loss Factors* reports. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

330 AEMO, *Integrated system plan*, July 2018, p. 53.

Figure 3.30: Change in MLFs in north Queensland from 1998 to 2018



Source: AEMO.

The Panel also notes on March 2019 AEMO, published draft MLF values for 2019/20 financial year. A significant reduction in MLF values occurred between 2018/19 and 2019/20.[331] This change is mainly driven by the unprecedented number of new generation connections expected to connect to the NEM in the coming year. This year's modelling done by AEMO includes 47 new connections providing approximately 5,600 MW of new capacity, mostly connecting in Victoria, New South Wales and Queensland. The majority of this new generation is connected to electrically weak areas of the network that are remote from the regional reference node, resulting in MLFs falling by large margins.

On 7 December 2018 and 5 February 2019, the AEMC received two rule change requests from Adani Renewables to amend the NER arrangements related to MLF application. Adani Renewables' main concerns are:

- Where a calculated forward-looking MLF is larger than the value that would be representative of the actual losses for a dispatch interval, a generator bears a risk of its bid price being greater than it would otherwise be for a more accurate/lower MLF. Such inaccuracy, according to Adani Renewables, leads to inefficient market outcomes and higher energy costs to consumers. Adani Renewables proposes to determine the MLFs according to the average loss factor methodology.[332]
- Under the current arrangements, any positive intra-regional settlement residue that accrues through the settlement process as a result of inaccuracies in relation to MLF's are distributed to transmission network providers. Adani Renewables proposes that

331 For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

332 For more information, see: https://www.aemc.gov.au/sites/default/files/2019-02/Rule%20change%20request.PDF

generators should receive an equal share of any distribution of intra-regional settlement residue.[333]

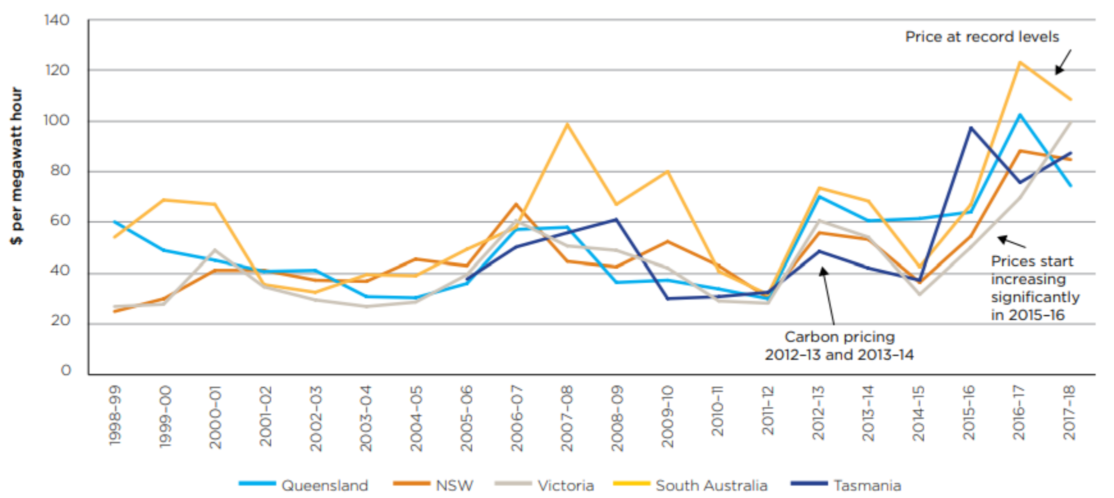
The AEMC has not yet initiated this rule change request.

The AEMC is also progressing the *Coordination of generation and transmission investment implementation - access and charging* review, which examines how generation and transmission investment may be more effectively coordinated, including how generators gain access to the transmission network. This longer-term work program will consider issues related to losses more holistically.[334]

3.4 Wholesale prices

Three years prior to the reporting period, the NEM wholesale prices increased significantly for all regions. Average prices in 2016/17 and 2017/18 were the highest they have been since the NEM started 20 years ago.[335] Figure 3.31 shows that annual volume weighted average wholesale electricity prices have been trending upwards for several years.

Figure 3.31: Annual volume weighted average prices in the NEM



Source: AER, *Wholesale electricity market performance report*, December 2018.

Note: Volume weighted average price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Since 2014/15, annual average prices have more than doubled in most regions:[336]

- In 2015/16, annual prices rose in every NEM region, increasing by around 50–60 per cent in Victoria, New South Wales and South Australia, and 160 per cent in Tasmania.

333 For more information, see: https://www.aemc.gov.au/rule-changes/intra-regional-settlement-residue-reallocation

334 For more information, see: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

335 AER, *Wholesale electricity market performance report*, December 2018, p. 8.

336 Ibid.

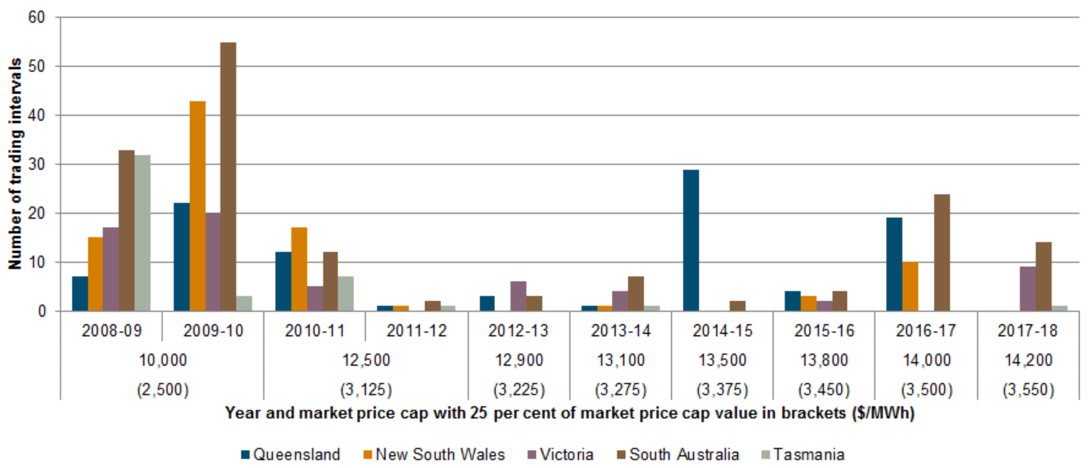
- In 2016/17, prices rose even more sharply, reaching record annual prices in all regions, except Tasmania. Wholesale prices increased by around 60–85 per cent in South Australia, New South Wales and Queensland, and 40 per cent in Victoria. In South Australia, average annual prices reached a record high of $123 per MWh, which is the highest annual average price in any region since the market started.
- In 2017/18, prices eased in most states but remained close to record levels. The annual price in South Australia remained the highest in the NEM. Victoria held the second highest average price, after increasing for the third year in a row. The annual price in Queensland fell to the lowest in the NEM.

3.4.1 Wholesale and contract price trends

Overall, the number of wholesale price spikes in the NEM decreased over 2017/18 relative to the previous financial year, with Victoria being an exception to this.

Figure 3.32 shows a count of trading intervals where the spot price has been at levels either at or above 25 per cent of the market price cap, since 2008/09.[337] Trading intervals are settled every half hour and consist of six dispatch intervals. The trading interval spot price is therefore the average of the price for each dispatch interval in that trading interval.[338]

Figure 3.32: Count of trading intervals where the spot price was above 25 per cent of the market price cap



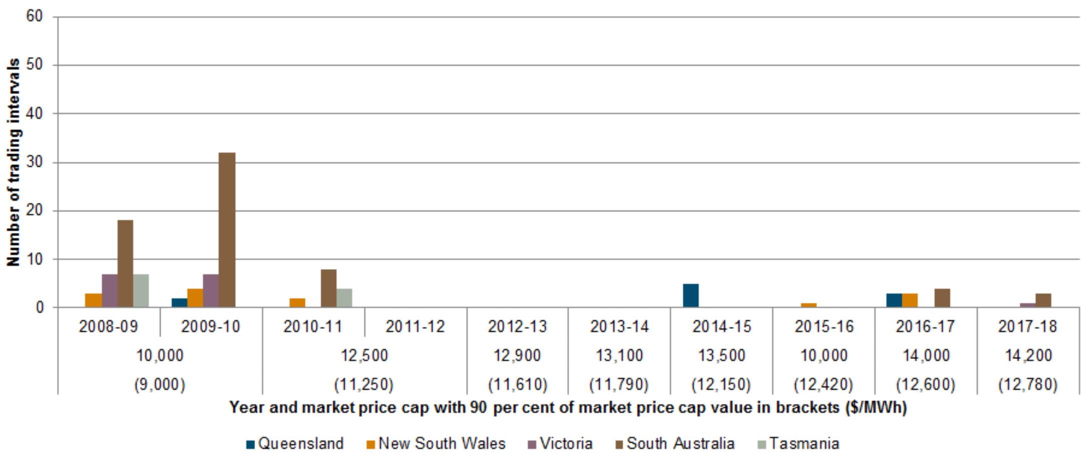
Source: AEMC analysis of NeoPoint database.

337 The market price cap is the maximum price that can be achieved in the NEM wholesale spot market. It has not been changed in absolute terms since 2012, but has been indexed to CPI and is increased by CPI movements at the beginning of each financial year. The market price cap was 14,200/MWh in 2017/18.

338 The Panel notes that on 28 November 2017 the Commission made a rule to align operational dispatch and financial settlement at five minutes. The rule provides a transition period of three years and seven months. Five minute settlement will commence on 1 July 2021.

This figure demonstrates that, historically, there are very few intervals where the NEM spot market price has been at levels approaching the market price cap.[339] This is reinforced by Figure 3.33, which shows a decreasing number of trading intervals over time, where the wholesale price has been at or above 90 per cent of the relevant market price cap. The Panel notes that across the NEM, between 2008/09 and 2010/11, markedly more price spikes (prices above 90 per cent of the MPC) were observed than in 2017/18. More detail on high prices events in 2017/18 is provided in appendix J.

Figure 3.33: Count of trading intervals where the spot price was above 90 per cent of the MPC



Source: AEMC analysis of NeoPoint database.

Victoria and South Australia were the only states where there were trading intervals where prices have been above 90 per cent of the market price cap in 2017/18:

- In Victoria, there was one such trading interval, compared to zero in 2016/17.
- In South Australia, there were three such trading intervals, compared to four in 2016/17.

Futures contract market prices

Reliable supply in the NEM is supported by the inherent and symmetrical incentive for buyers and sellers to obtain more certain revenues and costs. This incentive encourages buyers and sellers to agree to contracts that swap spot prices of electricity for a fixed price to manage these risks.[340] Contracts can be considered simply as another means of expressing the price of the same underlying product - electrical energy - meaning that spot and contract prices are intrinsically linked. The price of hedging contracts reflects the balance of expectations as to the level and volatility of future wholesale spot price outcomes, that is, if average spot prices are expected to increase in the future, contract prices will follow, and vice versa.[341]

339 There are 17,520 trading intervals in a non-leap year and 17,568 trading intervals in a leap year.

340 Appendix C provides a summary of how the contract market works and how it supports the reliability framework.

341 AEMC, *Reliability frameworks review*, interim report, December 2017, p. 18.

ASX wholesale futures prices for contracts purchased in 2017/18 for delivery in 2018/19 increased in New South Wales and the Australian Capital Territory due to a combination of the following factors:[342]

- Higher fuel costs for New South Wales generators from rising international gas prices.
- Supply issues for New South Wales coal generators in mid-2017. New South Wales coal generators (for example Mt Piper) faced various supply issues in 2017. This was triggered by the closure of the Hazelwood generator accompanied by unexpectedly high summer demand in 2016/17. These factors caused some generators to have higher output and consume more coal than expected. Attempts to replenish stockpiles through short term contracts were impacted by rail network constraints, technical issues at mines and industrial action.
- After the closure of Hazelwood in March 2017, the expectation that New South Wales would import less electricity from Victoria and more from Queensland, which has more expensive black coal as the primary generation source.

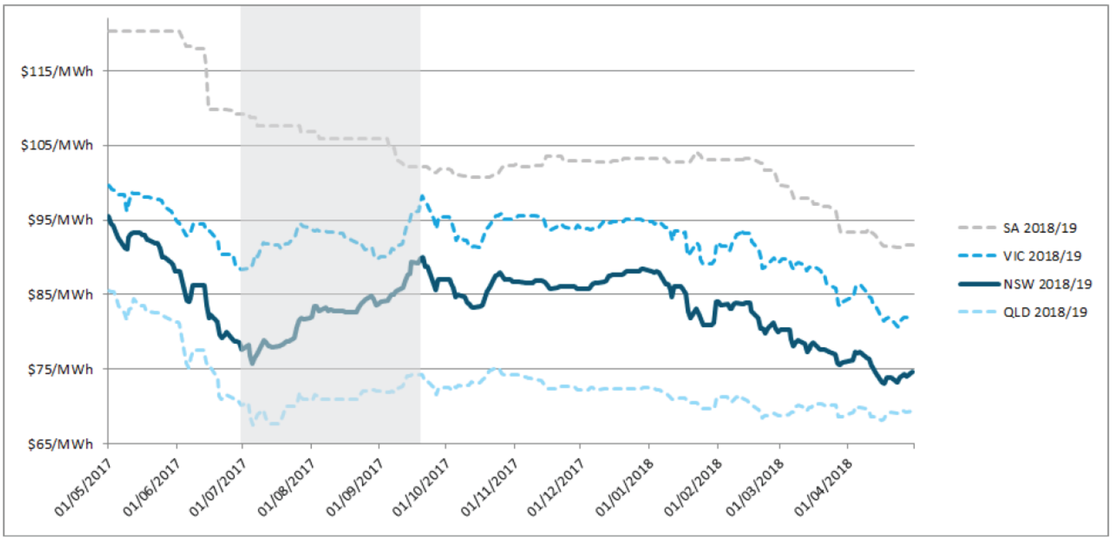
Figure 3.34 shows the expectation of elevated New South Wales wholesale prices in 2018/19 was built into the price of baseload strips traded on the ASX. While the South Australian futures price was on a downward trajectory, the Victorian and the Queensland prices were increasing at a lower pace than New South Wales. The shaded area shows the increase in New South Wales ASX futures prices during mid-2018 when there were concern around supply for New South Wales generators.

Figure 3.34 also demonstrates that from 2017/18 to 2018/19, futures prices decreased in South East Queensland, Victoria, South Australia and Tasmania. The reduction is driven by the estimated entry of 9,732 MW of accredited, committed or expected new generation and battery storage. The downward pressure this generation creates on wholesale prices more than offsets expected increases in gas and coal fuel prices over the period.[343]

342 AEMC, *2018 Residential electricity price trends*, December 2018, p. 40-41.

343 Ibid, p. i.

Figure 3.34: ASX prices of 2018/19 financial yearly baseload strips for QLD, NSW, VIC and SA



Source: ASX data. Reproduced from the AEMC's *2018 Residential electricity price trends*, December 2018, p. 42.

3.5 Frequency control ancillary services markets

Ancillary services under clause 3.11.1 of the rules are defined as services:

> ...that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality.

There are two types of ancillary services provided in the NEM:

- Market ancillary services are acquired by AEMO as part of the spot market in accordance with Chapter 3 of the rules. These services are acquired to provide the timely injection (or reduction) of active power to arrest a change in frequency. These services are generally referred to as frequency control ancillary services (FCAS).
- Non-market ancillary services are network support and control ancillary services (NSCAS), system restart ancillary services (SRAS) and other services acquired by TNSPs under connection agreements or network support agreements.[344] NSCAS may be procured by AEMO or TNSPs to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network. The NER give TNSPs the primary responsibility for acquiring NSCAS. AEMO is required to acquire NSCAS only if the NSCAS gaps remain unmet after TNSPs' attempt to procure.[345] SRAS are procured by

344 Defined in the NER, Chapter 10.

345 For more information, see: AEMO, *Network support and control ancillary services procedures and guidelines*,

AEMO in order to mitigate the impact of a major supply disruption. SRAS provides the capability to restart the power system from a 'black system' condition, where there is a complete loss of power supply in a given area. SRAS is provided by generators which have the capability to start, or remain in service, without electricity being provided from the grid.[346]

FCAS are procured by AEMO to increase or decrease active power over a defined timeframe, to keep the power system frequency within the requirements of the frequency operating standard.[347] There are two types of FCAS: regulating and contingency. Regulating FCAS is used to correct small deviations away from 50 Hz, while contingency FCAS are used to respond to larger frequency deviations, for example as a result of a contingency event. In the NEM, FCAS is sourced from eight markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised.

Figure 3.35 shows that the cost of delivery of market ancillary services in the NEM has increased significantly over recent years. The total FCAS costs increased from roughly $25 million in 2012[348] to around $220 million in 2018[349]. The increase was observed for all the raise contingency and regulating services (the services that are used to increase the frequency during both normal operation and following a disturbance), and also for the lower regulating service (the service that is used to lower the frequency during normal operation). In the review period, the total FCAS costs were: $71 million in Q3 2017, $60 million in Q4 2017, $25 million in Q1 2018 and $64 million in Q2 2018. The Panel notes that in Q3 2018 FCAS costs were $73 million – the highest quarter since 2008. Contributors to the increase in FCAS costs in Q3 2018 include reduced hydro supply and high priced events during the period (more than $10 million in FCAS costs accumulated on 25 August 2018 due to the trip of the QNI interconnector and subsequent separation of Queensland and South Australia).[350]

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https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Network-support-and-control-ancillary-services-procedures-and-guidelines

346 For more information, see: AEMO, *System restart ancillary services guideline 2017*, https://www.aemo.com.au/Stakeholder-Consultation/Consultations/SRAS-Guidelines-2017

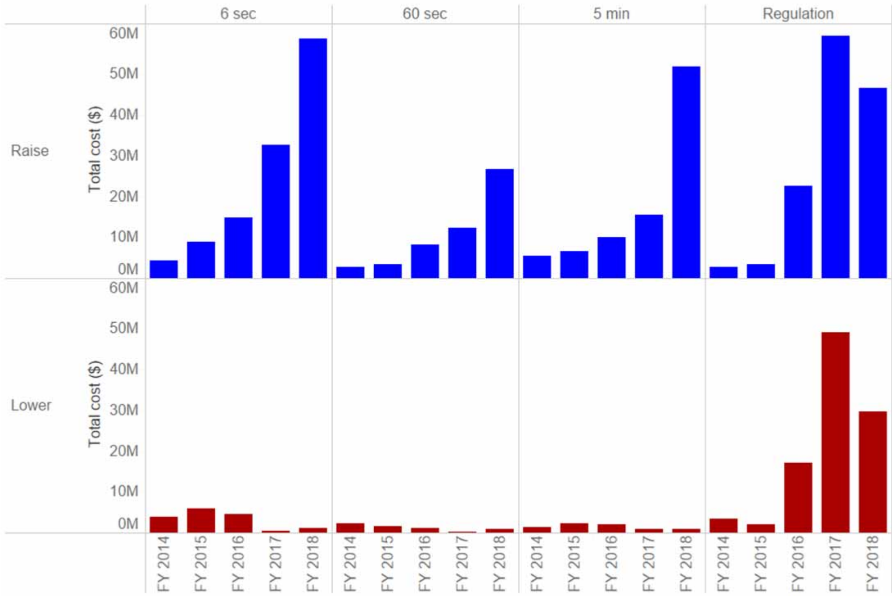
347 The Panel is currently reviewing the frequency operating standard. For more information, see: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard

348 Reliability Panel, *2018 Annual market performance review*, March 2018, p. 45.

349 AEMO's *Quarterly Energy Dynamics* reports.

350 Ibid.

Figure 3.35: NEM FCAS costs by service from 1 July 2013 to 30 June 2018



Source: AEMC analysis.

The Panel notes that a general reduction in the availability of FCAS may be linked to the following factors:[351]

- Energy provision and FCAS enablement are optimised within NEMDE. Thus, generators tend to price FCAS at the opportunity cost of energy provision. As Figure 3.31 and Figure 3.34 show, the increase in wholesale prices and future contract market prices in some regions over 2017/18 may lead to the corresponding increase in the FCAS prices. Further, increasing demands (especially in Queensland due to the ramp up of liquefied natural gas projects) incentivise participants to sell electricity at the wholesale market where prices are higher, rather than participate at the FCAS markets.
- Withdrawal of synchronous generation, which is typically operated in a way that allows it to offer capacity into FCAS markets, may reduce the physical supply of megawatts available to FCAS markets, leading to the FCAS prices increase. Several thermal generators that traditionally provided FCAS, such as the Northern Power Station in South Australia, have exited leading to less supply in the market. Until recently, renewable generation has not provided these services. However, the Hornsdale Wind Farm and the Hornsdale Power Reserve (HPR) in South Australia now provide FCAS.[352]
- Regulatory interventions may also create artificial scarcity and can therefore increase FCAS prices.

351 The Panel notes that it has no evidence as to the extent to which each of these factors has driven the FCAS market outcomes.
352 AER, *Wholesale electricity market performance report*, December 2018, p. 16.

- This includes the AEMO's requirement for 35 MW of pre-contingent regulation FCAS procurement from South Australian providers that was imposed by AEMO in late 2015 (see Box 1).
- Tasmania has historically provided low cost global FCAS. However, unplanned outages on the Basslink interconnector between Tasmania and the mainland (from December 2015 to June 2016 and again from March to June 2018) reduced global FCAS supply and put upward pressure on global FCAS costs. AEMO also imposed limits on the amount of regulation services Tasmania is permitted to provide to the mainland to better manage system security across the NEM.[353]

BOX 1: PRE-CONTINGENT REGULATION FCAS REQUIREMENT IN SOUTH AUSTRALIA

AEMO first introduced a 35 MW local requirement in October 2015 to ensure that there were adequate sources of regulation FCAS immediately available to manage frequency in South Australia, in the event of the region being separated from the rest of the NEM. In other words, generators which provide these services need to be on and running to be capable of providing the services before the need exists - this is effectively a security mechanism introduced by AEMO to protect South Australia in the event of separation.

Pre-contingent regulation FCAS requirement in South Australia was one of the main drivers of regulation service cost increase since 2015. In 2017, power system constraints, corresponding to this requirement, have the highest marginal value[1] among all constraints invoked in the system - $13.4 million.[2]

In October 2018, AEMO stated that the pre-contingent procurement of 35 MW regulation FCAS in South Australia is no longer necessary. According to AEMO, minimum synchronous unit requirements for South Australia system strength and an increase in the number of regulation FCAS providers, including the HPR, have ensured regulation FCAS is more readily available post-islanding of South Australia. The requirement was removed from 12 October 2018.

Source: AEMO, *Removal of the 35 MW pre-contingent regulation FCAS requirement in South Australia (SA)*, market notice, available at: https://www.aemo.com.au/Market-Notices?searchString=64716; AEMO, *NEM Constraint Report 2017 summary data*, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams

Note: 1- The marginal value of a constraint is the effect on total dispatch costs of alleviating that constraint by 1 MW.

Note: 2- In 2016, the marginal value of those constraints was $18 million. AEMO, *The NEM constraint report summary data 2017*, July 2018, accessed at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams

Despite the trend of FCAS prices increase over the years, in 2017/18 the costs of regulation FCAS decreased comparing to 2016/17. Contributors to lower FCAS prices included:[354]

- Additional supply from new technologies towards the end of 2017 (the HPR and EnerNOC).

353 Ibid.

354 AEMO, *Quarterly energy dynamics - Q1 2018,* May 2018, p. 3.

- Reduced pricing impact of the South Australian 35 MW FCAS constraint.

New participants

The regulating and contingency FCAS markets have historically attracted participation by synchronous, thermal, dispatchable generation. The withdrawal of synchronous generation may therefore contribute to a reduction in the availability of these services in the NEM. If this synchronous generation is displaced (either permanently or temporarily), the level of FCAS it provided will have to be procured from other sources. There is some evidence that the market is beginning to adapt to provide these new sources of FCAS.

On 1 July 2017, the provision of ancillary services was unbundled from the provision of energy as a result of a rule change made by the AEMC in 2016. The intention of the rule was to enable a more diverse group of suppliers to provide market ancillary services, to enhance competition in these markets and better enable AEMO to manage the frequency of the power system.[355]

EnerNOC, a provider of energy intelligence software and demand response services, registered as a Market Ancillary Service Provider in 2017 and is now participating in the raise contingency FCAS markets by offering a reduction in its aggregated portfolio of mostly commercial and industrial loads. EnerNOC reports that it is providing up to 70 MW of FCAS to support system security, making it the first time that distributed demand-side resource have provided grid balancing ancillary services in the NEM.[356]

At about the same time, the HPR was commissioned and began participating in the energy and FCAS markets. The HPR lithium battery is rated at 100 MW discharge and 80 MW charge, and has a storage capacity of 129 MWh. The HPR provides a range of services under commercial agreements between the South Australian Government, Tesla (the battery technology provider), and NEOEN (the operator of the Hornsdale Wind Farm). The services are: energy arbitrage, reserve energy capacity, network loading control ancillary services and FCAS.[357] The performance of the HPR is discussed in more detail in chapter 5.

AEMO reports that during Q1 2018 these two new technologies (i.e. demand response and battery storage) captured a larger share of FCAS markets. They supplied about 20 per cent of raise FCAS, compared to eight per cent in Q4 2017, displacing higher priced supply from existing technologies, largely coal (see Figure 3.36). AEMO notes that this increased competition in the FCAS markets coincided with a reduction in the price of offers from some existing providers.[358]

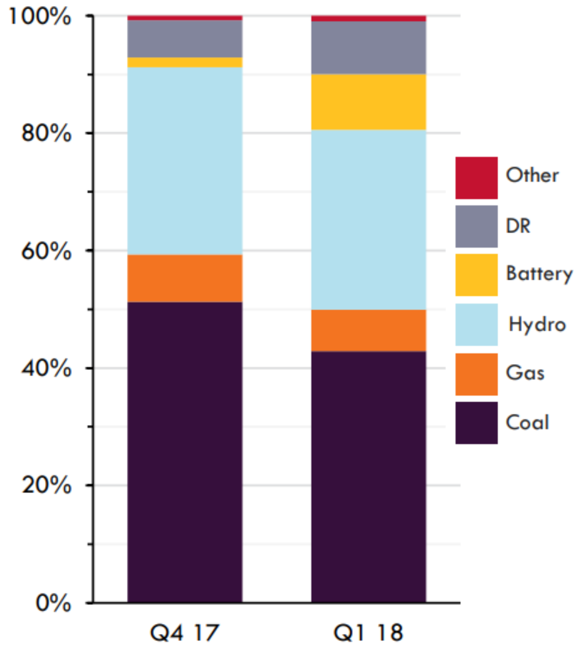
355 The unbundling framework established a new type of market participant – a Market Ancillary Service Provider – who can offer appropriately classified ancillary services loads or aggregation of loads into FCAS markets without having to be the financially responsible market participant at that connection point. See: https://www.aemc.gov.au/rule-changes/demand-response-mechanism

356 See: https://www.enernoc.com/press-releases/20156

357 The HPR is discussed in more detail in chapter 5.

358 AEMO, *Quarterly energy dynamics - Q1 2018,* May 2018, p. 13.

Figure 3.36: Raise FCAS supply by fuel type



Source: AEMO, *Quarterly Energy Dynamics-Q1 2018*, May 2018.

Moreover, following the successful trial, the Hornsdale Wind Farm is now registered and offering six FCAS services in the NEM. Further, in late 2018, ActewAGL's virtual power plant (VPP) was registered to provide three FCAS services. This is the first time a wind farm and a VPP have been registered to offer and deliver FCAS services in Australia.

This evidence suggests not only that these newer technology types are capable of providing FCAS, but they are increasing competition in those markets.[359] The impact of the new group of suppliers entering the FCAS markets on system frequency performance is discussed in more detail in chapter 5.

359 AEMC, *Frequency control frameworks review*, final report, July 2018, p. 26.

4 RELIABILITY REVIEW

This chapter describes:

- the Panel’s consideration of the reliability performance of the NEM in 2017/18
- major reliability incidents in the NEM in 2017/18
- projections of reliability
- work underway that focuses on reliability in the NEM
- recent relevant government interventions.

The Panel notes the following key reliability trends and outcomes:

- **Unserved energy:** There was no unserved energy in the NEM in 2017/18. In the past decade, there have been three occasions where there was unserved energy: in Victoria and South Australia in 2008/09, and in South Australia in 2016/17.[360]
- **Lack of reserve (LOR) notices:** AEMO publishes lack of reserve (LOR) notices to indicate to the market that there is a forecast lack of reserve, with the intention that the market will respond and increase the level of available generation supply. In 2017/18, there were 21 LOR notices issued. This represents a slight decrease from 22 notices that were issued in 2016/17.
- **Directions:** In 2017/18, there were no power system directions issued by AEMO to market participants to maintain the power system in a reliable operating state.[361]

From the perspective of reliability, 2017/18 was a unique year. The RERT was activated twice in 2017/18 to maintain the power system in a reliable operating state. Prior to 2017/18, the RERT had only been procured three times and had never been activated.[362]

4.1 Reliability assessment

Reliability means having an adequate amount of capacity (both generation and demand response) to meet consumer needs. This involves longer-term considerations such as having the right amount of investment, as well as shorter-term considerations such as making appropriate operational decisions, to make sure an adequate supply is available at a particular point in time to meet demand.

There are three indicators that the Panel has considered in assessing the reliability performance of the NEM for this AMPR:

360 The Panel acknowledges the load shedding events that occurred in Victoria on 24 and 25 January 2019. Analysis of this event has not yet been completed and so the Panel is not able to comment in detail on these events in this AMPR. The Panel intends to cover these load shedding events in detail in the 2019 AMPR, once AEMO has undertaken all its analysis and reporting functions.

361 AEMO may issue a direction to registered participants where it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state. The power system is assessed to be in a reliable operating state when: AEMO has not disconnected, and does not expect to disconnect, any points of load connection; no load shedding is occurring or expected to occur anywhere on the power system; in AEMO’s reasonable opinion the power system meets, and is projected to meet, the reliability standard. While there were no reliability directions in 2017/18, there were 32 direction events to maintain the system in a secure operating state. All but one of the direction events occurred in South Australia. Security directions are discussed in more detail in chapter 5.

362 The term activation is used to refer to the dispatch of unscheduled reserves.

- **Unserved energy:** the amount of customer demand that cannot be supplied within a region of the NEM due to a shortage of generation or interconnector capacity.[363]
- **Market reserve levels:** refer to the amount of spare capacity that is available, giving consideration to amounts of generation, forecast demand, demand response and scheduled network service provider capability.[364] In simple terms, market reserves can be thought of as the "buffer" that is made available by the market as part of the usual operation of the power system.
- **Interventions:** the reliability framework establishes that, if AEMO projects that the market is failing to meet the reliability standard, and the market has not responded to AEMO's requests for the market to respond accordingly, then, to meet the reliability standard and so deliver an acceptable level of reliability, AEMO may make a decision to intervene in the wholesale market. Intervention mechanisms are 'last resort' powers. Under the NER, there are three key intervention mechanisms related to reliability: the Reliability and Emergency Reserve Trader (RERT), directions and instructions.[365]

As in previous AMPRs, these indicators have been examined to demonstrate the overall reliability of the NEM.

4.1.1 The reliability standard and unserved energy

The reliability standard is focussed on the wholesale market and is the maximum expected unserved energy in a region for a given financial year.[366]

Crucially, this is not set at zero per cent. The current reliability standard is 0.002 per cent expected unserved energy. In simple terms, the reliability standard requires there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of forecast annual demand for electricity is expected to be supplied for a given year.

Importantly, setting the level of the reliability standard involves a trade-off, made on behalf of consumers, between the prices paid for electricity and the cost of not having energy when it is needed.[367]

363 Unserved energy excludes demand for energy that was not met due to security related issues or due to failures of the intra-regional transmission and distribution networks.

364 Reserves are defined in Chapter 10 of the rules. There are two types of reserves in the NEM: (i) Market reserves participate in the market and, at a high level, can be expressed as the balance of supply over demand; (ii) Out-of-market reserves (for example, the reliability and emergency reserve trader) are one of the available interventions permitted to be used by AEMO when it identifies, through a series of processes set out in the rules, that the market will not deliver enough market reserves to meet the reliability standard.

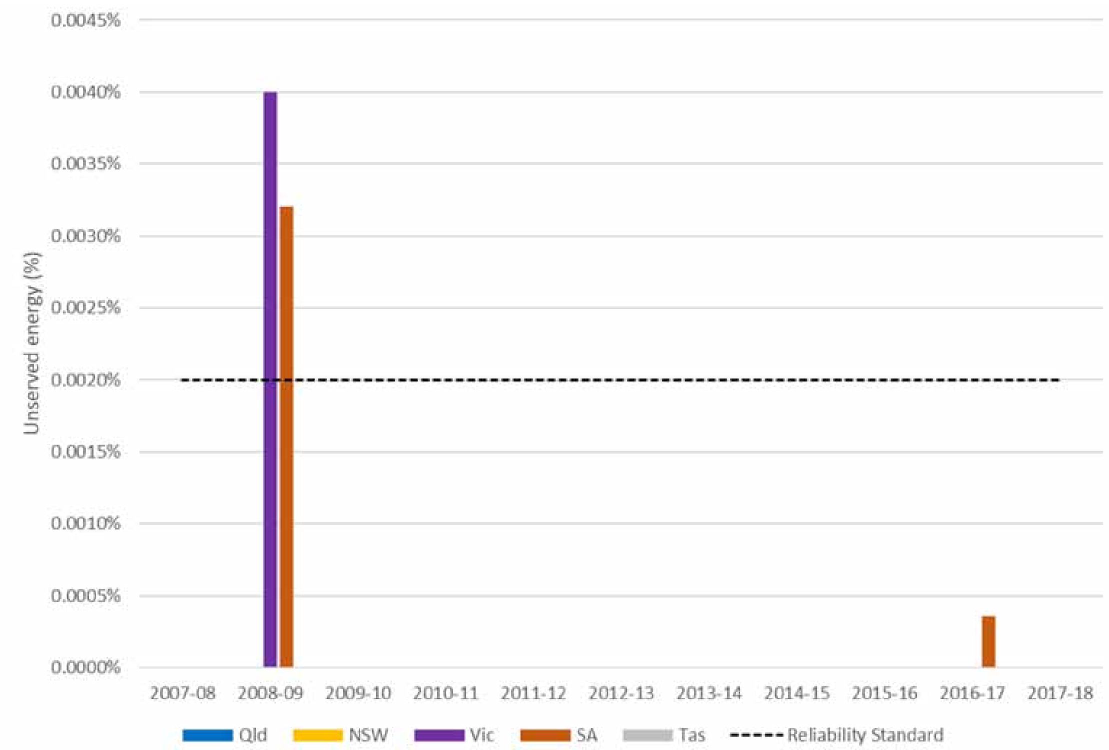
365 An instruction differs from a direction in the types of market participants AEMO can require taking action and the nature of the action taken. AEMO issues directions to generators to increase (or decrease) their output or a scheduled load to decrease (or increase) consumption. Instructions generally involve AEMO requiring a network service provider or a large energy user to shed load.

366 Rules clause 3.9.3C of the rules.

367 A higher reliability standard (that is, expected unserved energy less than 0.002 per cent) would in turn derive a higher market price cap (all things equal) which in turn should incentivise a supply- or demand-side response such as investment and operational decisions in generation, improving reliability. This may also improve liquidity in the contract market, as participants potentially would be exposed to higher risks and would prefer to have more certainty through entering into contracts. However, a higher market price cap would expose consumers that participate directly in the market, and retailers, to higher average spot prices. In turn, in a competitive market, retailers will recover these higher average spot prices from end consumers. The trade-off is therefore between two sets of costs, both of which are ultimately borne by consumers.

Historically, at a wholesale level, there has been very little unserved energy in the NEM. However, in recent years significant changes occurred at the supply side of the NEM, while peak demands did not change materially. Figure 4.1 compares the reliability performance of each region, in terms of unserved energy, over the past decade.[368] Unserved energy is expressed as a percentage of total annual energy consumption in each region.

Figure 4.1: Unserved energy in the NEM



Source: AEMO.

The reliability standard for the NEM sets a target that at least 99.998 per cent of demand for energy should be met. This standard was met in 2017/18. In the past decade, there have been two occasions where levels of unserved energy were greater than the level of the reliability standard. These events occurred in Victoria and South Australia in 2008/09.

Supply interruptions not related to the reliability of generation and transmission interconnection

Despite there being very little unserved energy in the past decade, individual consumers may have nevertheless experienced interruptions in supply. It is important to note that there are a number of other circumstances and events not related to generation reliability that may cause an interruption to consumer supply. These include:

368 The figure below does not include the most recent reliability event, which occurred in January 2019, as it falls outside the review period for this report. Detailed information on the event is not yet available.

- distribution network outages
- transmission network outages, in the non-bulk transmission sections of the transmission network (i.e. parts of the transmission network within a region, other than interconnectors)
- system security issues, including from imbalances in generation and demand triggered by shortages in generation capacity due to a non-credible contingency.[369]

Non-credible contingencies may result in large disturbances to power system security, including large deviations in system frequency from the normal operating frequency of the NEM. These large deviations may trigger automatic protection systems known as under frequency load shedding schemes, which shed volumes of consumer load in a controlled manner in order to arrest the fall in frequency.

As noted above, such interruptions are not classified as reliability interruptions and are not counted towards measurements of unserved energy. Under frequency load shedding schemes are discussed in more detail in chapter 5.

Figure 4.2 shows the interruptions of supply arising from incidents involving reliability, security, transmission networks and distribution networks from 2007/08 to 2017/18. The Panel notes that interruptions to consumer supply relating to the reliability of generators and interconnectors have historically represented a very small amount of all supply interruptions experienced by customers.

Over the period, only about 0.29 per cent of total supply interruptions (in terms of GWh) were the result of reliability events (brown area of the chart). Security events also represented a small portion (grey area) of all supply interruptions, at 4.05 per cent.

Estimates show that distribution network outages are responsible for about 94.38 per cent of supply interruptions (blue area of chart). The distribution network represents the largest set of infrastructure in the electricity supply chain, with many possible points of failure. Standards relating to distribution networks are set by jurisdictions.[370]

In relation to transmission interruptions, the Panel notes that while their proportion is very small (1.27 per cent), the consequences of such interruptions are complex and hard to manage.

Distribution and transmission outages tend to be spread over the year (though higher rates of outages occur at times of peak demand), whereas wholesale reliability issues almost always occur at times of peak stress on the system when demand is high due to extreme weather. The consequences of the increase in the frequency and intensity of heat events are discussed in detail in Bureau of Meteorology and CSIRO *State of the Climate 2018* report.[371] Weather conditions in 2017/18 are summarised in appendix F.

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369 Non-credible contingency events are generally considered to be events that are rare in occurrence, such as the combination of a number of credible contingency events occurring at the same time. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.

370 See appendix B for more information.

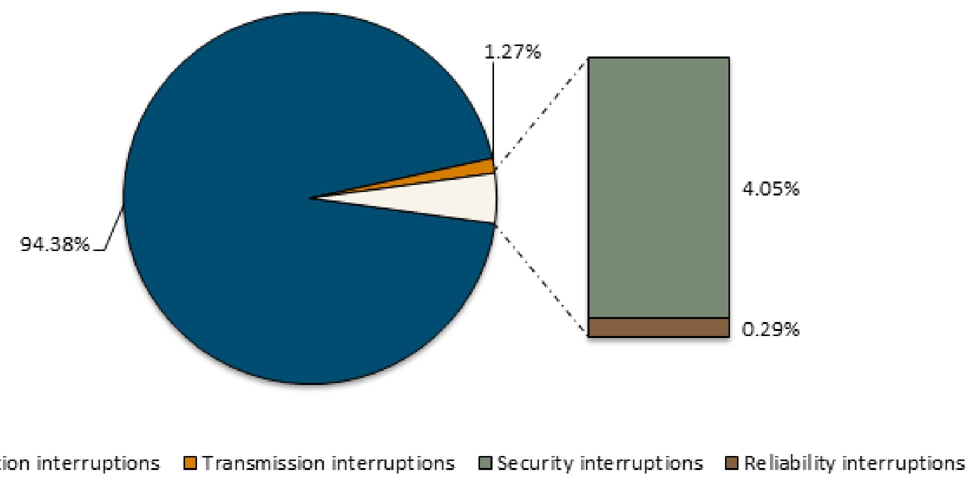
371 For more information, see: https://www.csiro.au/en/Showcase/state-of-the-climate

In the 2017 AMPR, the Panel provided similar analysis to that included in the Figure 4.2 below, but covering a period from 2007/08 to 2015/16. We have reproduced the same figure for this AMPR, but expanded the data to include the period out to 2017/18.

Notably, the proportion of interruptions due to security has doubled from 1.61 per cent (for the 2007/08-2015/16 period) to 4.05 per cent (for the 2007/08-2017/18 period). This is mainly due to the South Australian black system event in 2016/17.

System security is discussed in more detail in chapter 5.

Figure 4.2: Sources of supply interruptions in the NEM from 2007/08 to 2017/18



Source: AEMC analysis and estimates based on publicly available information from AEMO's incident reports and the AER's RIN economic benchmarking spreadsheets.

Note: With regard to outages on the distribution network in 2017/18, a number of distribution network service providers (DNSPs) have reported unsupplied energy data on a calendar year rather than financial year basis via the RINs. For these DNSPs, the data for the 2017 calendar year was treated as 2017/18 financial year data. The DNSPs reporting unsupplied energy data on a calendar year basis are: ActewAGL, Endeavour Energy, Energex, Ergon, SA Power Networks and TasNetworks.

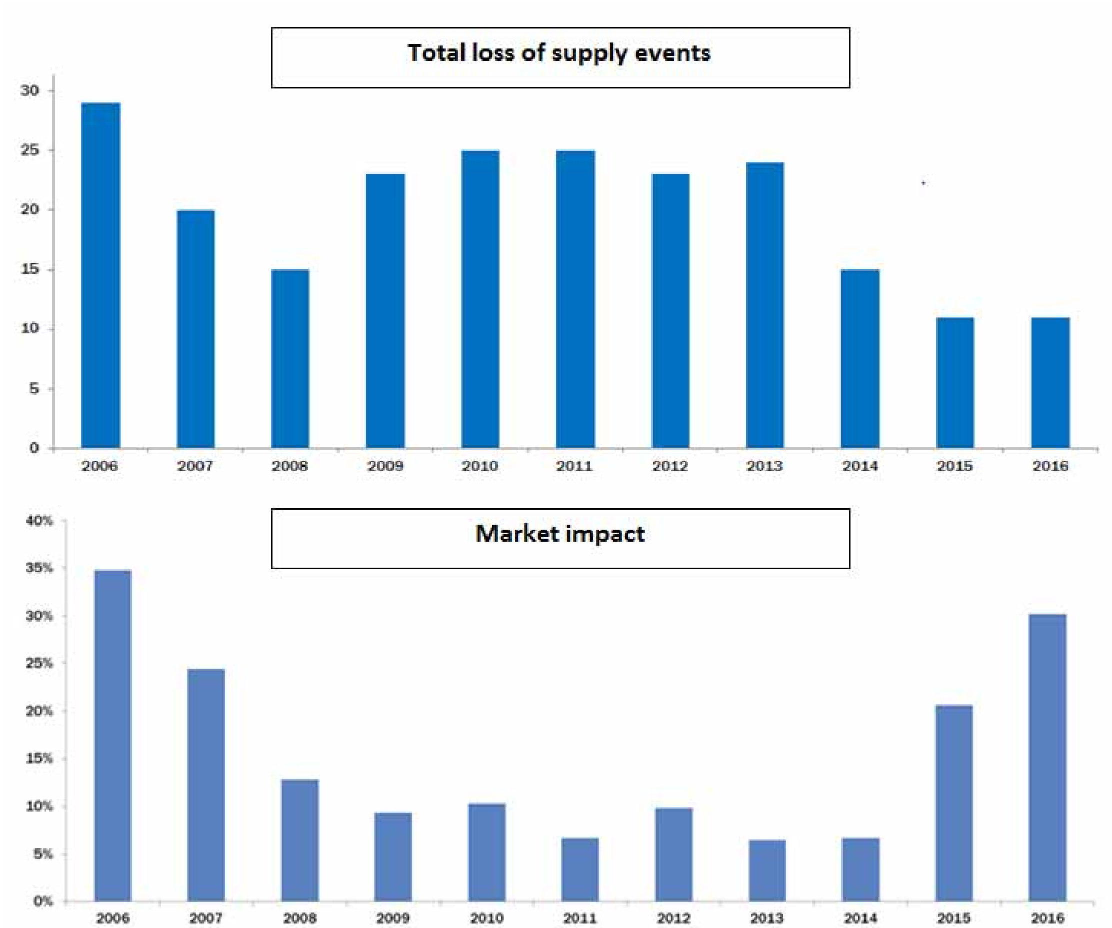
In relation to interruptions due to the transmission network, the Panel notes that while the number of total loss of supply events[372] has decreased over the years, the market impact[373] of those events has increased significantly. Figure 4.3 shows the total numbers of supply loss events and the percentage of dispatch intervals where disturbances on the transmission network impacted wholesale market outcomes. The main driver of market impact indicator increase in 2015 and 2016 was the increase in percentage of dispatch intervals, where events on the South Australian transmission network impacted market outcomes. This increased from zero per cent in 2014, to 17 per cent in 2015 and 14 per cent in 2016. Further, in 2016

372 Loss of supply events measure the number of times energy is not available for set periods of times to transmission network customers. These thresholds vary for each business between between 0.05 and 1.0 system minutes, as outlined in the published AER's Service Target Performance Incentive Scheme decisions.

373 Market impact measures the relative disruption of outages on customers. The relative disruption is determined by estimating the impact on energy price in the NEM - if an outage increases the energy price by more than $10/MWh it is counted in the market impact measure.

the market impact indicator increased notably for the Victorian transmission network, from two per cent in 2015 to ten per cent in 2016.[374]

Figure 4.3: Transmission interruptions and their market impact



Source: AER, *Electricity transmission network service provider performance report*, September 2018.

For more information on transmission and distribution networks performance, see appendix B.

4.1.2 Market reserve levels

Market reserve levels refer to the amount of spare capacity available given amounts of generation, forecast demand and demand response, and scheduled market network service provider capability at any point in time.[375] In simple terms, market reserves can be thought of

374 AER, *Electricity transmission network service provider performance report*, September 2018.

375 Reserves are defined in Chapter 10 of the rules.

as the “buffer” that is made available by the market as part of the usual operation of the power system.

A market reserve level indicates the difference between available resources in the market to meet demand for energy, and the level of energy demanded. Market reserves act as a buffer to help manage unplanned system developments, such as the loss of a large generator or a sudden increase in demand.

In the short term (from real time to seven days ahead of real time), AEMO informs the market of ‘lack of reserve’ (LOR) conditions to encourage a response from market participants to provide more capacity into the market: generators may offer in more supply, or consumers can reduce their demand. Both responses have the effect of improving market reserve margins, and maintaining power system reliability.

AEMO issues declarations that these conditions exist, in order to signal to the market there is either a present or potential future shortage of market reserves. AEMO issues both forecast and actual LOR condition notifications.

Prior to February 2018, AEMO calculated the LOR levels as follows:

- Lack of reserve level 1 (LOR1): when the consecutive occurrence of both the largest and the second largest relevant credible contingency events would result in load shedding occurring as a result of a shortfall of available capacity reserves.
- Lack of reserve level 2 (LOR2): when the occurrence of the largest relevant credible contingency event would result in load shedding as a result of a shortfall of available capacity reserves.
- Lack of reserve level 3 (LOR3): when load shedding is occurring or about to occur as a result of a shortfall of available capacity reserves.

A LOR3 indicates a significant impact on the NEM, as it indicates that load is either being shed, or load shedding is imminent. A LOR1 has a less significant impact on the NEM as it means that load shedding is still only likely to occur following a multiple contingency.

Until December 2017, when the AEMC made *Declaration of Lack of Reserve conditions* rule, LOR1 and LOR2 levels were determined solely on the basis of the largest credible contingencies in a region, as described above.[376] This approach had limited ability to take into account risks of unexpected reductions in reserves due to factors that exist now in the changing power system, such as a sudden decrease in demand or a decrease in scheduled or intermittent generation.

After the rule change was made, a new process developed by AEMO introduced a probabilistic element into the determination of LOR levels, which allows for the impact of estimated reserve forecasting uncertainty in the prevailing conditions, known as the forecasting uncertainty measure (FUM), to be accounted for when calculating the LOR levels. These estimates are made on the basis of modelling past reserve forecasting performance for demand, output of intermittent generation and availability of scheduled generation.

376 For more information see: https://www.aemc.gov.au/rule-changes/declaration-of-lack-of-reserve-conditions

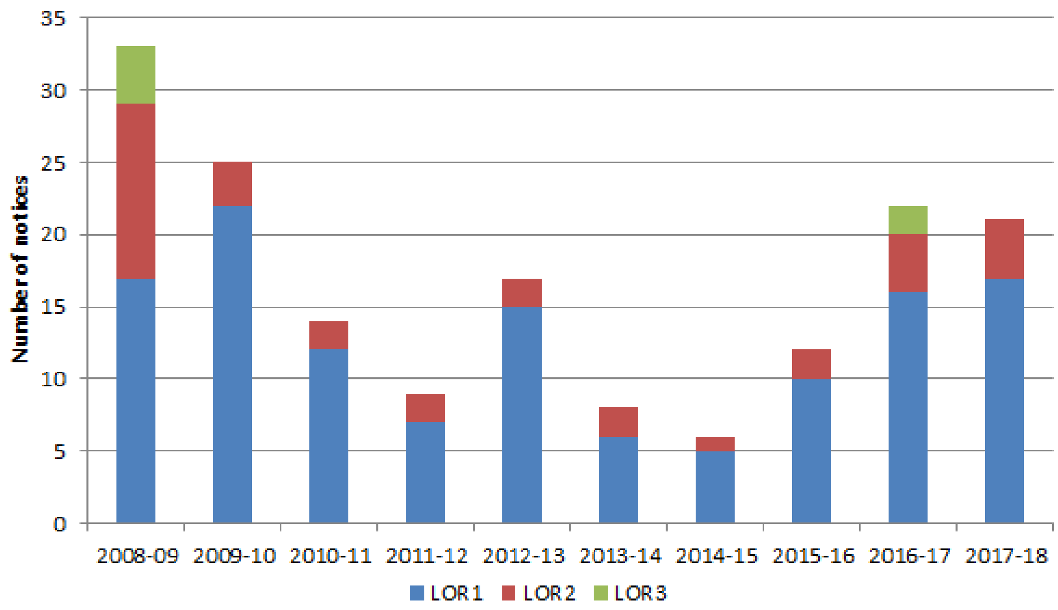
As a result, LOR levels are now calculated as follows:[377]

- LOR1 is still at least the size of the two largest credible contingency events as a minimum, except when the FUM is larger than these, at which point LOR1 is set by the FUM.
- LOR2 is still at least the size of the largest credible contingency event, except when the FUM is larger than this, at which point LOR2 is set by the FUM.
- LOR3 is unchanged.

Given that the new LOR framework was introduced in February 2018, 2017/18 LOR notices include notices declared under the old framework as well as the new framework.

Figure 4.4 shows the number of LOR notices issued in the NEM since 2008/09. In 2017/18, there were 21 LOR notices issued, which is a slight decrease from the 22 notices issued in 2016/17. Further, in 2017/18 there were no LOR3 notices issued.[378] However, the number of LOR notices issued in the past two years has been higher than previous periods, which may indicate that the supply-demand balance has become tighter.

Figure 4.4: LOR notices issued in the NEM



Source: AEMO.

4.1.3 Intervention mechanisms

Directions and instructions

377 The three conditions are defined in AEMO's *Reserve level declaration guidelines,* which were introduced in January 2018.

378 In 2016/17, LOR3 notices were issued on 8 February 2017 in South Australia and 10 February 2017 in New South Wales.

Despite the fact that system reliability is based around market-driven investment, retirement and operational decisions, if there is a risk to the secure or reliable operation of the power system, AEMO can direct:

- scheduled, semi-scheduled and non-scheduled market generators to increase or decrease energy output
- scheduled loads to decrease or increase consumption.[379]

Directions may also apply to market network service providers (currently only Basslink).[380]

AEMO may also issue instructions, if there is a risk to the secure or reliable operation of the power system. Instructions can be issued to all registered participants that cannot be subject to a direction (i.e. other than scheduled plant or a market generating unit).

AEMO can instruct a large energy user to temporarily disconnect its load or reduce demand.[381] AEMO may also instruct a network service provider to shed and restore load consistent with schedules provided by the relevant state government.

During 2017/18, no directions or instructions to market participants were issued to maintain the system in a reliable operating state. All directions issued by AEMO in 2017/18 were to maintain the power system in a secure operating state. These are discussed in chapter 5. In 2016/17, two directions were issued to maintain the system reliability.

Reliability and Emergency Reserve Trader (RERT) mechanism

The RERT is an existing intervention mechanism that allows AEMO to contract for additional, emergency reserves such as generation or demand response that are not otherwise available in the market. They are additional reserves because they are in addition to the “buffer” that is made available by the market as part of the usual operation of the power system.

The RERT is an important part of the regulatory framework, allowing AEMO to use a safety net at times when a shortfall in market reserves is forecast, or where practicable, to maintain power system security. These additional reserves are commonly referred to as “emergency reserves” or “strategic reserves” since they are used as a last resort when the market has not otherwise provided reserves to reduce the likelihood of blackouts, typically during periods when the demand supply balance is tight, for example, summer.

379 Unless (in the Registered Participant’s reasonable opinion) it would be a hazard to public safety, materially risk damaging equipment or contravene any other law, to follow the direction. For instance, a direction could involve AEMO directing a generator to cancel a maintenance activity and return to service as soon as possible.

380 Clause 4.8.9(a) of the NER. A direction can be issued in relation to scheduled plant or a market generating unit. A scheduled plant is defined in the rules as “a scheduled generating unit, a semi-scheduled generating unit, a scheduled network service or a scheduled load classified by or in respect to that Registered Participant in accordance with Chapter 2.” It is current AEMO policy for a battery >5MW to be registered as a scheduled generating unit, and therefore a battery >5MW could be directed as scheduled plant. The only currently registered market network service provider is Basslink. As at 8 October 2018, the only registered market scheduled loads and registration load applicants (and therefore the only scheduled loads potentially subject to a direction) were Wivenhoe Power Station (Queensland, 480 MW total for two units), Dalrymple North Battery Energy Storage System (South Australia, 30 MW), Hornsdale Power Reserve Pty ltd (South Australia, 80 MW) and Tumut 3 Pumps (New South Wales, 600 MW). While it is possible for AEMO to direct a scheduled load, AEMO advises it has not historically directed a scheduled load. Typically scheduled loads would not be consuming when prices are high. A market generating unit is defined in the rules as “a generating unit whose sent out generation is not purchased in its entirety by the local Retailer or by a Customer located at the same connection point and which has been classified as such in accordance with Chapter 2”. This category includes non-scheduled market generators.

381 This only applies to large users who are registered participants.

The Panel notes that the AEMC is currently progressing a rule change request to enhance the RERT. A draft determination was published on 7 February 2019. The discussion of RERT in this report relates to the existing provisions, rather than changes proposed under the draft rule.[382]

The RERT guidelines, which are made and reviewed by the Panel, specify three types of RERT based on how much time AEMO has to procure the RERT prior to the projected reserve shortfalls occurring:

- long-notice RERT - between ten weeks' and nine months' notice of a projected reserve shortfall
- medium-notice RERT - between ten weeks' and one week's notice of a projected reserve shortfall
- short-notice RERT - between seven days' and three hours' notice of a projected reserve shortfall.

Typically, AEMO sets up a RERT panel of providers for both the medium-notice and short-notice RERT and only triggers the procurement contract when it has identified a potential shortfall and after seeking offers from RERT panel members.[383] There is no panel for the long-notice RERT; rather, contracts are signed following the close of a public tender process.

Under the NER, AEMO may determine to enter into reserve contracts, that is to procure the RERT, to ensure that the reliability of supply in a region meets the reliability standard for that region.[384] Prior to 2017, the RERT had only been procured three times and had never been activated. In 2017, AEMO procured reserves through the long-notice RERT and introduced new panel members to the short-notice RERT panel through the Australian Renewable Energy Agency (ARENA) - AEMO demand response trial.[385]

Further, the NER state that AEMO may activate RERT, that is dispatch reserves, to ensure that the reliability of supply meets the reliability standard, and where practicable, to maintain power system security.[386] When the RERT is activated, AEMO is required to set the wholesale market prices to the value which AEMO, in its reasonable opinion, considers would have applied had the RERT activation not occurred. The RERT was activated twice in 2017/18 to maintain the power system in a reliable operating state. On 30 November 2017, following a forecast LOR2 in Victoria, the RERT was activated for the first time. AEMO also entered into reserve contracts in January 2018, and dispatched the RERT in Victoria and South Australia on 19 January 2018. AEMO has noted that both short- and long-notice RERT providers were used. These two events are summarised below.

In addition, AEMO entered into reserve contracts in New South Wales in June 2018 due to forecast LOR2s. However, conditions improved and the RERT was not dispatched.

382 For more information, see: https://www.aemc.gov.au/sites/default/files/2019-02/Draft%20determination.pdf

383 AEMO has the discretion to use a tender process in addition to using panel members in the case of the medium-notice RERT.

384 Clause 3.20.3(b) of the NER.

385 ARENA-AEMO trial is discussed in more details in section 4.4.11.

386 Clause 3.20.7(a) of the NER.

30 November 2017

On 30 November 2017, following a forecast LOR2 in Victoria, a RERT contract was procured and RERT providers were dispatched for the first time.[387]

AEMO first issued a LOR2 notice for Victoria on the day at 04:51[388] on 30 November 2017 when pre-dispatch PASA identified a reserve shortfall for the time period starting from 15:30 that afternoon and lasting until 17:00. AEMO sought a market response. This was followed by another notice at 11:10.

At 13:53, AEMO issued a market notice to inform the market that it had entered into a reserve contract and may activate the RERT for the time period starting 15:30 until 21:30. At 15:20, AEMO issued another notice informing the market that the RERT had been activated.

AEMO noted in its event report that, given there was insufficient market response, AEMO activated a total of 32 MW of unscheduled reserves from three reserve contracts. The reserve was activated at 15:30. The first reserve contract was deactivated at 21:30, after completion of its minimum continuous run time of six hours. Second and third reserve contracts were deactivated at 16:30, after completion of their minimum continuous run times of one hour.

One contract had a pre-activation lead time of one hour, with an activation lead time of two hours.[389] The other two contracts had activation lead times of one hour, with no pre-activation required. There were no pre-activation costs incurred for this event. Total event cost (i.e. excluding any availability payments that may have been incurred previously) amounted to $0.89 million in Victoria, made up entirely of activation costs.

18 and 19 January 2018

On 18 January 2018 at 17:00, following a forecast LOR2 in Victoria, AEMO informed the market that it has entered into a RERT contract and may dispatch the RERT on 19 January 2018 from 14:30 to 18:30.[390]

On 19 January 2018, AEMO continued to issue forecast LOR2s. At 11:22, it informed the market of its intention to seek additional reserves through the RERT panel. At 13:43, AEMO informed the market that RERT contracts were activated and would apply from 14:00 until 20:00.

AEMO noted in its report into the event that, given that there was insufficient market response, it activated 130 MW of unscheduled reserves across eight reserve contracts in Victoria, and 6.5 MW of unscheduled reserves across two reserve contracts in South Australia. These contracts were activated between 14:00 and 15:30 on 19 January 2018, with all ten contracts being deactivated by 20:00. On 18 January 2018, about 500 MW was pre-

387 For more information, see: AEMO's market notices and *Summer 2017/18 operations review report, Annexure A - 30 November 2017*, May 2018, available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report/Summer-operations-report-2017-18

388 All times are AEST.

389 Pre-activation lead time means the maximum period required to prepare the reserve equipment for activation. Activation lead time means the maximum period required by the reserve provider to activate reserve in response to an activation instruction.

390 For more information, see: AEMO's market notices and *Summer 2017/18 operations review report, Annexure B - 19 January 2017*, May 2018, available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report/Summer-operations-report-2017-18

activated in Victoria (due to pre-activation lead times of 20+ hours); however these contracts were not subsequently activated on 19 January 2018. AEMO stated that these reserves were pre-activated to ensure availability in case of a large contingency event which did not eventuate and were to be dispatched once LOR3 condition occurred.

BOX 2: RERT COSTS

Prior to 2017/18, RERT-procured reserve contracts had never been dispatched, with reserve contracts procured on only three occasions:[1]

- 33 days in summer 2005 (30 January – 4 March)
- 54 days in summer 2006 (15 January – 10 March), and
- three days in summer 2014.

The cost of the first two procurement rounds – in the form of availability payments – was $5.4 million, with the cost of the last procurement round (in 2014) close to zero.

The RERT was activated twice during the summer of 2017/18. According to AEMO, total RERT costs for 2017/18 were $51.99 million, comprising:

- $27.03 million in availability payments
- $21.56 million in pre-activation costs
- $3.23 million in activation costs, and
- $0.17 million in other costs.

The volume of energy dispatched by AEMO via the RERT during the two activations was:

- 107 MWh for the 30 November 2017 activation, and
- 390 MWh for the 19 January 2018 activation.

The total RERT costs for summer 2017/18 were estimated to be around $104,608 per MWh, which is approximately seven times the market price cap, and approximately four times the value of Victorian residential customer reliability.

AEMO stated that this translated to a cost of $6 per customer. However, the Panel notes this amount refers only to the per-customer share of the $52 million recovered from residential customers. The significant costs of the RERT to medium and larger energy users (i.e. commercial and industrial customers) were not included. According to the AEC, many medium and large energy users received bills related to the RERT of hundreds of thousands of dollars. The bulk of the $52 million was paid by Victorian and South Australian businesses, which constitute more than 60 per cent of electricity consumption.

In January 2019, there were two significant reliability events whereby AEMO used RERT, and involuntary load shedding also occurred. AEMO entered into RERT contracts and activated the RERT in South Australia and Victoria on 24 January 2019 and in Victoria on 25 January 2019. AEMO stated that nearly 3,000 MWh of RERT was activated and avoided 1,252 MWh of involuntary load shedding at a total cost of $30.62 million. The avoided load shedding cost is

$24,457/MWh which is lower than 2017/18 costs.

Source: AEC, *The RERT locker*, 2 March 2018, https://www.energycouncil.com.au/analysis/the-rert-locker; AEMO, *RERT 2017-18 cost update*, 2018, p. 1; AEMO, *Value of customer reliability fact sheet*, 10 November 2015, p. 2; AEC, *RERT locker II: the sequel*, 9 August 2018, https://www.energycouncil.com.au/analysis/rert-locker-ii-the-sequel; Panel's MMS database analysis; AEMO, submission to the AEMC's *Enhancement to the Reliability and Emergency Reserve Trader* draft determination, March 2019, p. 6.

Note: 1 - Some form of mechanism for the system operator to contract for reserves such as the RERT or reserve trader provisions, has been a feature of the NEM since its commencement in December 1998. Over time, periodic reviews of the reserve trader provisions have led to various amendments, including initially postponing and then removing its expiry date, as well as changes to its scope and operation. The RERT itself (as distinct from previous versions of a strategic reserve) was developed as part of the Panel's *2007 Comprehensive reliability review*. The RERT was incorporated into the NER in July 2008, and replaced the reserve trader provisions.

In June 2018, following a number of LOR2 notices in New South Wales, AEMO entered into reserve contracts (i.e. it procured the RERT) on 7 June and again on 8 June. The RERT was not activated on either of those events. There were no costs associated with these events.

In summary, AEMO's review of its summer operations for 2017/18 summer has concluded, in relation to RERT, that:[391]

- RERT was an effective tool at improving reserves across a range of time horizons.
- RERT providers were highly engaged, and communication between them and AEMO was efficient, which enabled sound decision-making in determining the requirement for, activation of, and subsequent deactivation of reserves.
- Demand response resources trialled through the AEMO/ARENA pilot were effective, and performed to expectations. Ongoing assessment of these resources and their adequacy will continue over the next two summers.
- Using AEMO's deterministic approach to managing reserves, which was in place at the time of activation of RERT on 30 November 2017 and 19 January 2018, there were sufficient levels of RERT available to mitigate the risk of load shedding against the single largest credible risk determined at the time of peak demand.
- AEMO noted it will work to improve communications around activation of reserves and verification of quantities of demand response.

The Panel also notes for summer 2018/19 AEMO sought the following RERT resources:[392]

- While resources under RERT have been identified across most NEM regions as a precautionary measure, long-notice RERT was sought in Victoria only, as a result of the forecast breach of the reliability standard.
- AEMO contracted reserves in Victoria as follows:
  - Reserves available from the second year of the three-year joint AEMO/ARENA Demand Side Participation trial.[393] Under the trial, 90 MW of reserves[394] can support reliability in Victoria.

391 AEMO, *Summer 2017-18 operations review*, p. 31

392 AEMO, *Summer 2018/19 readiness plan*, November 2018, p. 13.

393 For more information, see: https://www.aemo.com.au/Media-Centre/ARENA-and-AEMO-join-forces-to-pilot-demand-response-to-manage-extreme-peaks-this-summe

394 70 MW in Victoria and 20 MW in South Australia.

    - 40 MW of off-market reserves using long-notice RERT contracts, bringing the total to 130 MW.
- AEMO was also seeking to enter into a minimum of 405 MW of short- and medium-notice RERT panel agreements (in Victoria and South Australia).[395] Because the panel agreements do not commit AEMO to a reserve contract or require upfront availability payment commitments, AEMO was seeking up to a total of 800 MW of reserves to cover the risks associated with the extreme scenarios.[396]

AEMO's approach to procuring reserves to manage reliability shortfalls in Victoria during 2018/19 summer was intended to provide up to 930 MW of reserves in total, while only committing to reserve contracts for 40 MW of reserves secured under long-notice RERT.[397]

The Panel acknowledges that during summer 2018/19, in particular, in January 2019, there were two significant reliability events whereby AEMO used RERT, and involuntary load shedding also occurred. AEMO entered into RERT contracts and activated the RERT in South Australia and Victoria on 24 January 2019 and in Victoria on 25 January 2019. AEMO stated that nearly 3,000 MWh of RERT was activated and avoided 1,252 MWh of involuntary load shedding at a total cost of 30.62 million. The avoided load shedding cost is $24,457/MWh.[398] The Panel will provide more detail on these events in its 2019 AMPR.

4.1.4 Supply side variability and reliability

As identified in section 3.2, the NEM generation fleet is currently going through a period of significant change, with a number of ageing thermal generators being mothballed or retired, combined with the entry of significant volumes of variable, renewable generation.

These changes in the generation mix may have a number of implications for the reliability of the NEM. In particular, there is a number of reliability implications associated with the potential coincident unplanned outages of thermal generation.[399] The variability of supply from intermittent renewable generation may also impact on both the reliability and security of the power system.[400]

This section considers both of these potential impacts on the overall reliability of the NEM.

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395 AEMO sets up a RERT panel of providers for both the medium-notice and short-notice RERT and only triggers the procurement contract when it has identified a potential shortfall and after seeking offers from RERT panel members. Panel members for short-notice RERT agree on prices when appointed to the panel, whereas panel members for medium-notice RERT do not, and prices are negotiated if and when reserve is required. The RERT panel allows AEMO to run an expedited tender process in short- and medium-notice situations, as the tendering process is pre-agreed and makes use of pre-determined agreements and standard tender forms. AEMO has the discretion to use a full tender process in addition to using panel members in the case of the medium-notice RERT. There is no panel for the long-notice RERT; rather, contracts are signed following the close of a public tender process. For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/RERT-panel-expressions-of-interest

396 Final amounts accessible under panel agreements are to be published by AEMO in accordance with the RERT Guidelines.

397 AEMO, *Summer 2018/19 readiness plan*, November 2018, p. 14.

398 AEMO, submission to the AEMC's *Enhancement to the Reliability and Emergency Reserve Trader* draft determination, March 2019, p. 6.

399 An outage is considered 'unplanned' if the outage cannot reasonably be delayed beyond 48 hours.

400 Some of the impacts of variable renewable generation are discussed in more detail in chapter 3 of this report.

Thermal generation availability

Planned and unplanned outages of thermal generation may have an impact on reliability in the NEM in future years.

Many thermal coal generating systems in the NEM have overall capacities well over 1,000 MW, with individual units within those generating system being as large as 744 MW.[401] The unexpected trip of just a few of these large units can immediately place stress on the system, especially at times of high demand.

Furthermore, a number of the NEM's thermal generators have been in service for over 40 years. The age of these units may make them more prone to forced outages (due to plant breakdown), or to increase the frequency and length of planned outages (due to necessary maintenance and repair works). This will become particularly prevalent amongst those generators that are past their technical operating lifespan.

A complicating factor is that any increases in the number of periods of tight supply-demand balance in the market may result in limited flexibility as to when planned outages for maintenance of these older units can occur, while time to recall a generator outage can be long. Furthermore, there are emerging challenges in some states where generation maintenance needs to be rescheduled to maintain system strength during periods of low demand. This is typically during shoulder months, when traditionally maintenance would be scheduled in preparation for higher demands in winter and summer.[402]

Given the limited window in which maintenance can be scheduled, there are increasing operational risks associated with maintaining reliability and system security when maintenance does proceed. Equally, however, if preventative maintenance cannot occur in a timely manner due to power system security concerns, there is higher risk of plant failure and impacts on overall reliability during high demand periods.[403]

To further examine the potential reliability issues associated with the availability of large thermal coal generating units, the Panel has included some data on outages published by AEMO in the *2018 ESOO.* The Panel has also requested from AEMO some additional data on seasonality of generation availability.[404] This was further examined with the focus on the last quarter of 2017/18 through AEMO's *Quarterly energy dynamics* report.

The Panel notes that there were a number of outages of large thermal units in Victoria during the 25 January 2019 load shedding events in that state. As detailed data and reporting on this event is not yet available, and as it falls outside of the reporting period of this 2018 AMPR, the Panel intends to provide more detailed commentary on this event as part of the 2019 AMPR.

401 The capacity of the Kogan Creek Power Station is 744 MW.

402 AEMO, *Electricity statement of opportunities*, August 2018, p. 61.

403 Ibid.

404 Plant availability is defined in the NER chapter 10 as the active power capability of a generating unit, based on the availability of its electrical power conversion process and assuming no fuel supply limitations on the energy available for input to that electrical power conversion process.

2018 ESOO

In its *2018 ESOO*, AEMO found that because the existing thermal generation fleet is ageing, it appears likely that the aggregate reliability of thermal plant may be reducing. This is most evident over the past three years.[405]

This is evidenced through the change in generator outage data that AEMO collected from participants and then used in the *2018 ESOO*.

This outage data is included in Table 4.1, which compares forced outage[406] assumptions used by AEMO in the *2018 ESOO* and *2017 ESOO*. The Panel notes that the forced full outage rates[407] increased in 2018 projections for all generator aggregation, with the most significant increase for black coal generators in New South Wales before 2022.[408]

Table 4.1: **Forced outage assumptions in 2018 ESOO**

GENERATOR AGGREGATION	FULL OUTAGE RATE – *2018 ESOO*	FULL OUTAGE RATE – *2017 ESOO*
Brown coal	5.34%	4.10%
Black coal QLD	2.42%	2.05%
Black coal NSW – until 2022	6.56%	2.05%
Black coal NSW – after 2022	3.88%	2.05%
CCGT	1.33%	0.62%
OCGT	3.56%	0.66%
Steam Turbine	4.58%	1.73%
Hydro	1.58%	0.82%

Source: AEMO, *2018 Electricity Statement of Opportunities*, August 2018.

In regard to summer 2018/19, the Panel notes that total brown coal-fired generation during Q4 2018 was 8,227 GWh, representing the lowest quarterly average since market inception. This was a function of extended outages at Yallourn and Loy Yang A power stations. Black coal-fired generation in New South Wales was three per cent higher than in Q3 2018 despite lower electricity demand, driven by higher wholesale electricity prices and increased availability. Output from Queensland's black coal-fired generation was consistent with Q3 2018 results, with higher wholesale prices balancing the impact of lower availability. There

405 Market participants provide AEMO, via an annual survey process, details of the timing and size of historical unplanned generator outages. This data was used by AEMO to calculate the probability of forced outages, which were then applied randomly to each unit in the ESOO modelling. To protect the confidentiality of this data, AEMO calculated outage parameters for a number of technology aggregations. AEMO, *Electricity statement of opportunities*, August 2018, p. 48.

406 Forced outages exclude planned or strategic withdrawals of available capacity. An outage (including full outage, partial outage, or a failed start) is considered "forced" if the outage cannot reasonably be delayed beyond 48 hours.

407 Forced outage rates depict the probability of different types of generators experiencing an unplanned full outage.

408 In the *2018 ESOO*, a number of methodological changes have been made compared to the *2017 ESOO* with regard to outage modelling. For a number of technology aggregations, there has been a clear deterioration in reliability over the period where data is available. To reflect more realistic expectations of generator performance, among other things, AEMO has used only the most recent three years of outage data for brown coal, black coal, and gas-fired steam turbines. The Panel acknowledges that this change in methodology may contribute to the increased outage rates.

was also a relatively high number of sudden generator trips when completed to recent quarters, particularly in Queensland and New South Wales. At this stage, however, Q4 2018 results are not indicative of a longer-term trend, with the number of sudden unit trips in 2018 consistent with results in recent years.[409]

Seasonality of thermal generation outages

Seasonal outage/availability patterns of thermal coal generation can be relevant to the overall reliability of the power system. Historically, planned outages have occurred in the shoulder seasons (usually the periods outside of the summer peak), when demand is typically more moderate, so that availability of generation is maximised for the peak summer demand period. As noted above, any change in these patterns may impact on overall system reliability.

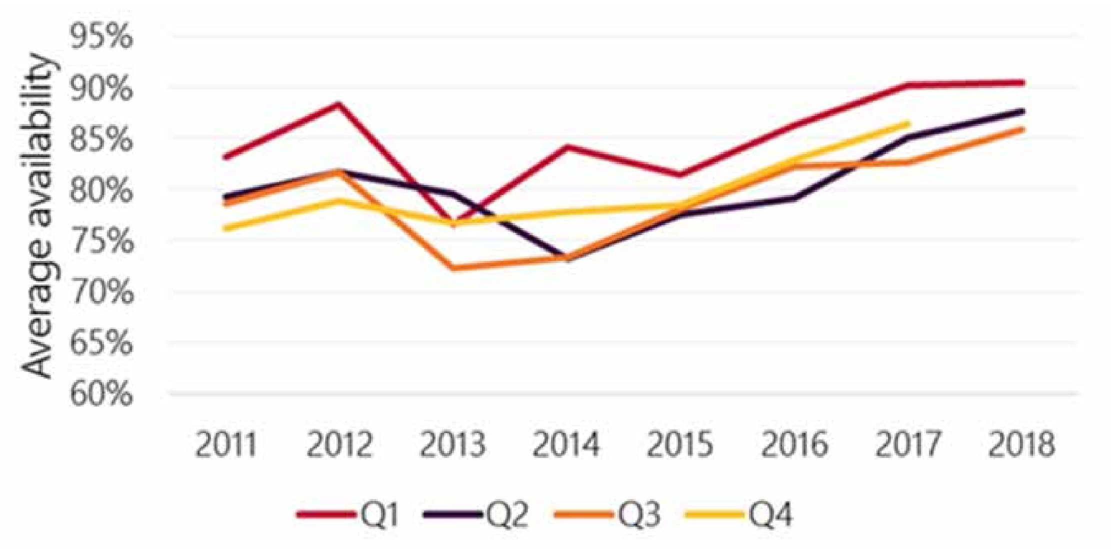
AEMO has provided the Panel with some analysis of historic outage patterns in the NEM. Generally, this analysis shows that availability of thermal coal generation has improved across all seasons in some regions, but has shown a recent decrease in others.

In relation to the seasonality of historic outages, both forced and planned, AEMO notified the Panel that:

- The Queensland coal fleet's average availability has increased evenly across all quarters of the year. The timing of outages during a year appears not to have changed (see Figure 4.5).
- The New South Wales coal fleet's average availability appears to have decreased from 2017 to 2018. This is especially notable for Q2 and Q3 (see Figure 4.6).
- The Victorian coal fleet's average availability has been steady: in 2017 and 2018 there appears to have been an increase in availability in Q2 (shoulder/winter season), with lower availability in other quarters, particularly in 2017 Q4 (see Figure 4.7).

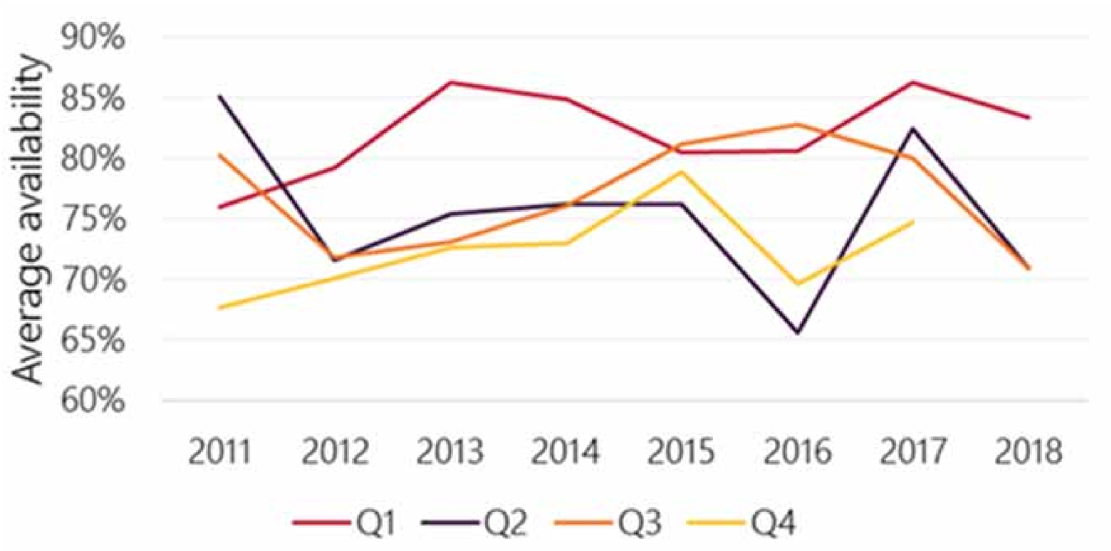
409 AEMO, *Quarterly energy dynamics - Q4 2018*, February 2019.

Figure 4.5: Queensland - coal fleet availability



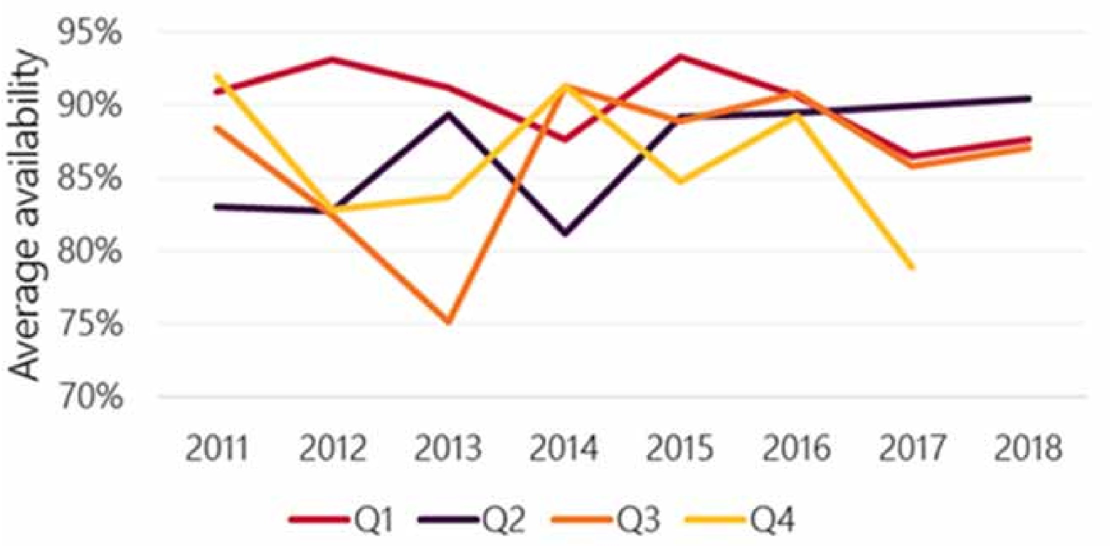
Source: AEMO.

Figure 4.6: New South Wales - coal fleet availability



Source: AEMO.

Figure 4.7: Victoria - coal fleet availability



Source: AEMO.

In its *Quarterly Energy Dynamics,* AEMO reports, among other things, on actual coal generation availability. The following key trends were observed in coal generation availability in the last quarter of 2017/18:[410]

- Average black coal-fired generation reduced compared to the recent quarters, driven by many planned and unplanned outages of the black coal fleet in New South Wales. The New South Wales fleet recorded its lowest availability since Q4 2016, largely due to extended unit outages at Bayswater and Eraring Power Stations.[411] Average output at these power stations reduced in Q2 2018 by 314 MW and 282 MW respectively compared to Q2 2017.
- Results for the Queensland black coal-fired fleet were mixed in Q2 2018, recording increased availability and generation compared to Q2 2017, but a slight reduction in generation compared to Q1 2018. The largest increases in generation compared to Q2 2017 were at Gladstone and Millmerran Power Stations (+297 MW and 288 MW, respectively), reflecting increased availability at lower prices.
- Brown coal-fired generation was steady in Q2 2018 compared to Q2 2017, reflecting few outages during the quarter. The one exception was at Yallourn Power Station, which had at least one unit on a planned outage for 75 per cent of Q2 2018.

410 AEMO, *Quarterly energy dynamics - Q2 2018,* August 2018, p. 8.

411 According to AEMO, it is typical for a greater number of planned outages to be scheduled for the lower demand 'shoulder' seasons of autumn and spring.

Renewable generation availability

Due to the variable nature of wind and solar, there is potential for material variations in energy availability from these generators, which may have reliability implications for the system.

In its *South Australian Renewable Energy Report,* AEMO stated that analysis of renewable generation output in 2016/17 showed that:[412]

- The maximum variation of all South Australian wind generation was 56.7 per cent of registered capacity across 30-minute periods.
- Estimated rooftop PV generation varied by up to 24.3 per cent of estimated capacity across 30-minute periods.

These variations represent more extreme examples of the rapidity of changes in output from renewable generation that can occur. Furthermore, they will not necessarily result in a reliability issue, as long as there is sufficient alternative supply or demand response available to maintain the balance of supply and demand.[413]

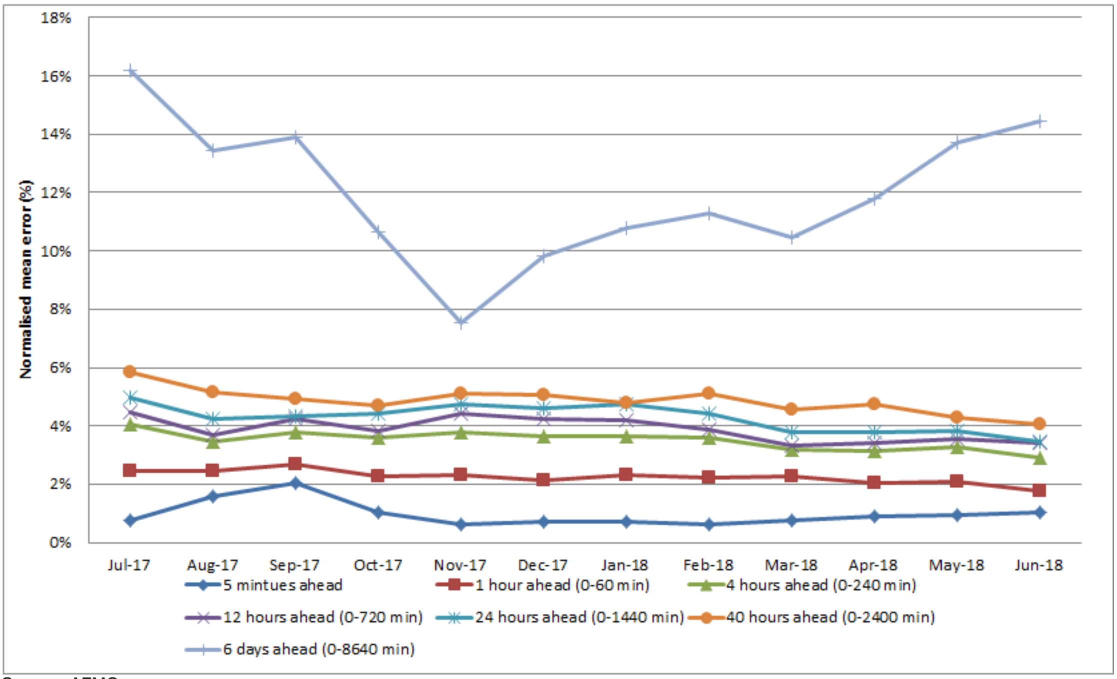
However, although these kinds of changes would not be expected to occur on a regular basis, they can pose challenges to the secure and reliable operation of the power system, particularly if they occur at times of very high demand.

In addition to these more extreme rapid variations in output, AEMO has also examined the degree of difference that can occur between forecast and actual variable renewable generation output, over different timeframes. This is illustrated in Figure 4.8 below.

412 AEMO, *South Australian renewable energy report,* November 2017, p. 4.

413 The Panel notes that these various alternatives could include supply from dispatchable generation, or supply via interconnection with other regions of the NEM. They also include response from the demand side, which is becoming an increasingly important part of the NEM wholesale market.

Figure 4.8: Australian wind energy forecasts for 2017/18



Source: AEMO.

This figure shows that the accuracy of forecasts of variable renewable generation generally improves closer to real time. However, at times of peak demand, even small variations within a tight timeframe can create reliability issues, if dispatchable generation is not available to replace this capacity.

AEMC analysis of historic forecasting accuracy also shows that the level of deviation between actuals and forecasts has generally remained steady over time. However, accurate forecasting has become more complex due to greater volumes of variable renewable energy generation entering the NEM.[414] Further, forecasting of variable renewable generation beyond seven-day time horizon is hard and, as could be expected, there is a significant degree of difference that can occur between forecast and actual variable renewable generation output. The Panel's assessment of AEMO's forecasting accuracy is outlined in appendix E.

The accuracy of forecasting is therefore a key factor in the effective integration of variable renewable generation into the NEM.[415] On this basis, forecasting systems will be an increasingly important tool for promoting efficiencies in NEM dispatch, pricing, system reliability and security, as renewable generation continues to make up a larger share of the generation mix.

414 AEMC, *Reliability frameworks review,* final report, July 2018, p. 31.

415 The Panel acknowledges that demand forecasting accuracy will also play a key role in this process.

The Panel notes that AEMO and ARENA have started the *Market Participant 5-Minute forecast* project to enable self-forecasting by utility-scale wind and solar projects, on a voluntary basis. As a part of this project, wind and solar farms will be able to submit their own forecasts to AEMO. This will allow local measurements to be combined with AEMO's modelling to improve the overall accuracy. Self-forecasting for a longer horizon, such as a few hours or even a day ahead, could provide a tangible reliability benefit by better informing AEMO and the market of the likely future output of wind and solar generators. In doing so, it would make wind and solar generators operate more similarly to scheduled generators who offer into the market.[416]

The combined impacts of thermal and renewable generation availability

As noted above, the Panel considers that changes in both the thermal and variable renewable generation mix may have implications for reliability. This is particularly the case where the kinds of issues discussed above occur simultaneously, during a period of high demand.

As an example of this combined impact, the Panel notes the event that occurred in South Australia on 8 February 2017.[417] During this event, unserved energy was recorded for the first time since 2008/09. AEMO instructed load shedding (100 MW for 27 minutes)[418] to restore the power system to a secure state.[419] Key contributing factors to this event included a number of forced and planned thermal generation outages, actual wind genertion output being lower than forecast, and timeframes for thermal generation to come online.

The 8 February 2017 incident involved rapidly changing supply from both renewable and thermal generation. At the point in time when demand was at its highest level during the day, wind generation was much lower than forecast and thermal generation capacity was reduced due to forced outages. The Torrens Island A1 and Pelican Point Gas Turbine 12 units were unavailable due to pre-existing outages. Together they represent 285 MW of capacity. A further 153 MW of thermal capacity was unavailable due to forced outages. These outages represented 17 per cent of South Australia's gas powered generation capacity. The operator at Pelican Point advised AEMO of a start-up time which would not have enabled AEMO to meet the system security requirements under the rules. Of the installed operational capacity in South Australia of 5,157 MW, a total of 3,046 MW was available at 18.00 on 8 February to contribute to the operational peak demand of 3,085 MW.[420]

This incident demonstrated the potential combined impacts of both thermal generator outages and changes in actual as opposed to forecast volumes of wind generation on the reliability of the electricity supply. The Panel acknowledges that there were a number of thermal generator outages on 24 and 25 January 2019, when load shedding occurred in

416 For more information, see: https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Market-Participant-5-Minute-Self-Forecast and https://arena.gov.au/funding/programs/advancing-renewables-program/short-term-forecasting/

417 This event is described in detail in 2017 AMPR.

418 The actual amount of load shed by South Australian Power Networks was approximately 300 MW due to a software error. Source: SA Power Networks, *Statement re load shedding event (8 February 2017)*, 15 February 2017, p.1.

419 AEMO, *System event report, South Australia, 8 February 2017*, February 2017, p. 4. In the report, AEMO stated that it was still undertaking investigations into the reviewable operating incident on 8 February 2017, including seeking information and clarification from participants.

420 Reliability Panel, *2017 Annual market performance review*, March 2017, p. 59.

Victoria. The extent to which these outages contributed to those load shedding events will be examined by the Panel in the 2019 AMPR.

4.2 Major reliability incidents

The Panel notes that it is AEMO's role to determine whether an event is defined as a security or reliability event. That is, AEMO determines whether any unmet demand is defined as unserved energy in relation to the reliability standard.

In 2017/18, there was no single incident that occurred that contributed to unserved energy at a wholesale level.[421] Accordingly, there is no major reliability incident to be reported here. Major security incidents are discussed in chapter 5.

As mentioned above, major incidents involving load shedding occurred in Victoria and South Australia on 24 and 25 January 2019. It is AEMO's responsibility to determine whether the incidents were security or reliability related. Calculations of unserved energy will be made ex post by AEMO, and provided to the Panel to inform the 2019 AMPR.

4.3 Reliability projections

4.3.1 AEMO's *2018 ESOO* unserved energy forecasts

AEMO publishes an Electricity Statement of Opportunities (ESOO) on an annual basis. This report provides technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the NEM over a 10-year outlook period.

The analysis from AEMO includes projections of future potential expectations of unserved energy. The projections of USE are signalled to the market with the intention of eliciting a response from participants to address the projected shortfall.

AEMO published the *2018 ESOO* in August 2018. As required under clause 3.13.3(q) of the rules, the ESOO includes projections of aggregate demand and energy requirements for each region, generating capabilities of existing and planned units, anticipated generator retirements and operational and economic information.[422] Box 3 summarises AEMO's processes and assumptions in forecasting supply reliability.

BOX 3: FORECASTING SUPPLY RELIABILITY IN THE *2018 ESOO*

The *2018 ESOO* includes forecasts of unserved energy for the NEM regions for a 10-year period, from 2018/19 to 2027/28. The modelling uses a statistical approach, which calculates an average USE over a number of demand outcomes (based on eight historical reference years of weather) and random generator outages, weighted by likelihood of occurrence, to

421 In 2016/17, there was one reliability incident that contributed to unserved energy. It occured on 8 February 2017 in South Australia.

422 AEMO, *Electricity statement of opportunities*, August 2018, p. 17.

determine the probability of any supply shortfalls. These shortfalls have been expressed in terms of the expected unserved energy and compared to the NEM reliability standard.

The *2018 ESOO* modelling has been performed under three scenarios: neutral, slower and faster pace of change. The ESOO scenarios assess supply adequacy of existing and committed generation, storage and transmission projects, under three different demand projections driven by faster or slower transformative change in the NEM.

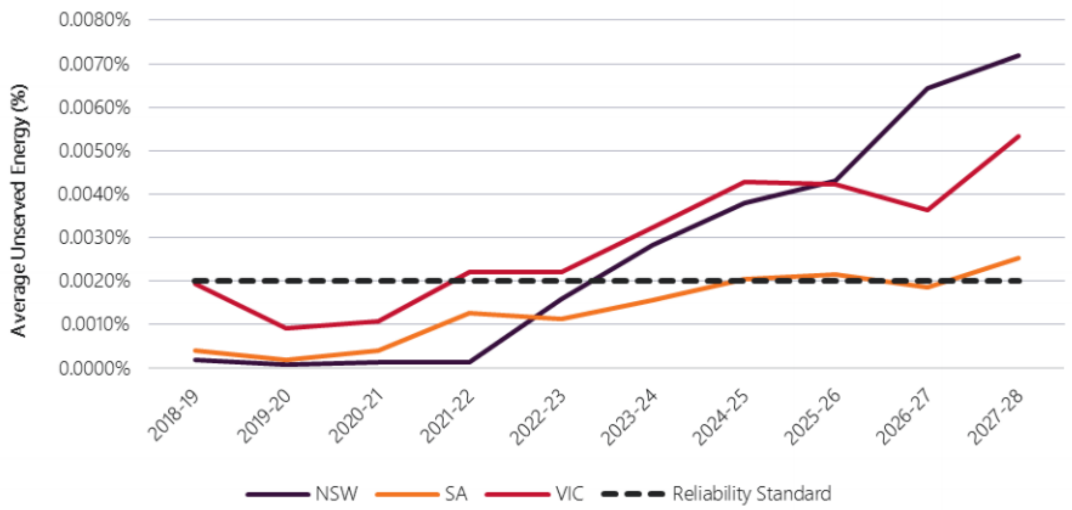
Comparing to *2017 ESOO*, among others, AEMO introduced the following modelling improvements in *2018 ESOO*:

- Wind and solar resource data – more site-specific assessment of variable renewable generation contribution at times of peak demand for committed resources in new locations.
- Battery behaviour – implemented two alternative charge/discharge profiles for residential battery storage reflecting both convenience charging and aggregated charging.
- Network performance – undertaken a detailed review of the modelling of weather-dependant dynamic line ratings. The updated line rating information more closely reflects historical network performance.
- Number of random samples – the number of random samples of generator outages has been increased.The neutral scenario outcomes are based on 1,600 simulations, and 800 simulations were modelled for all other scenarios. In the *2017 ESOO*, 210 simulations were modelled for each scenario.
- Generator ratings and performance – all generator summer capacities were reviewed to ensure that these values reflect likely performance under summer peak conditions. AEMO has also implemented higher outage rates for many generators based on historical outage data provided by market participants.

Source: AEMO, *Electricity Statement of Opportunities*, August 2018.

Figure 4.9 shows forecast unserved energy (USE) in the next 10 years in Victoria, New South Wales, and South Australia. This forecast is based on the Neutral scenario demand forecasts. The Panel notes that this forecast assumes no new generation projects being developed beyond those that are currently committed.

Figure 4.9: Forecast USE outcomes



Source: AEMO, *2018 Electricity Statement of Opportunities,* August 2018.

Key insights highlighted by AEMO in the *2018 ESOO* include:

- Without RERT, there was a heightened risk of USE exceeding the reliability standard in Victoria during the 2018/19 summer, with projected USE only marginally below the reliability standard.
- The key drivers of the heightened USE risk assessment in the short term are:
  - An increase in the projected likelihood of unplanned and forced generation outages
  - An increase in expected peak demand across Victoria and South Australia
  - A reduction in the export capacity of Basslink.[423]
- After the 2018/19 summer, the risk of USE is forecast to reduce in the short term, due to a slight reduction in forecast peak demand and the introduction of additional renewable generation.
- As forecast peak demand begins to grow, and Torrens Island A and Liddell Power Stations retire in 2019-21 and 2022 respectively, USE is projected to begin rising. Forecast USE is above the reliability standard in Victoria by 2021/22, in New South Wales by 2023/24, and in South Australia by 2024/25.
- There is no USE forecast in either Tasmania or Queensland over the 10-year modelling horizon.

According to AEMO, the following is required to address the reliability gap:

423 *2018 ESOO* modelling assumed the Basslink interconnector operation with a 478 MW limit in both directions based on forward-looking transfer capabilities supplied in the MT PASA. This represents a reduction in transfer capacity from Tasmania to Victoria of 116 MW compared to the *2017 ESOO*.

- After the closure of Liddell Power Station, the equivalent[424] of 350 MW of dispatchable capacity (beyond that already operating or committed) would be required by 2023/24 across Victoria, New South Wales, and South Australia, rising to 1,160 MW by 2027/28.
- Transmission augmentations and new lines would reduce the need for more dispatchable capacity by alleviating transmission congestion, leveraging resource diversity, and maximising the value of the existing generation fleet.

4.3.2 AEMO's GSOO projections of gas availability

The Panel reports on projections of gas availability and impacts on electricity markets. Reliable electricity supply depends on availability of fuel for all generators. Flexible gas-powered generation is an essential component of the NEM generation fleet, particularly as the NEM transitions to a fleet with a high penetration of variable, renewable generation. Gas generating units can usually turn on within a few hours if they have fuel available. Without these generators, reliability in the NEM could be compromised.

The Panel notes that 2017/18 was an eventful year in the gas industry. In particular, the eastern and south-eastern Australian gas markets were significantly impacted by the increase in volumes of gas being used for liquefied natural gas (LNG) exports and the subsequent coupling of the Australian gas market to international markets.

The increase in volumes of gas required for export has led to a tightening of domestic gas supply.[425] One of the main changes for the gas industry in 2017/18 was the Federal Government's introduction of the Australian Domestic Gas Security Mechanism. Under this mechanism the Federal Minister for Resources can determine whether export restrictions should be imposed to avoid any potential shortfall in meeting domestic demand for gas. In 2017, the Federal Government decided not to apply export controls for the 2018 year. However, it reached a Heads of Agreement[426] with the east coast LNG consortia under which they made commitments in relation to the domestic supply of gas in 2018 and 2019.

The projections of gas availability are presented in AEMO's *2019 Gas statement of opportunities.*The gas supply-demand balance in eastern and south-eastern Australia remains tight with gas production in southern Australia continuing to decline in the medium term, which increases reliance on production from Queensland to serve the needs of South Australia and New South Wales.

AEMO forecasts adequate supply to meet gas demands from existing and committed projects until 2023 under the expected market conditions. The immediate risk of shortfalls previously projected has been reduced due to the following changes:

- The Northern Gas Pipeline has now commenced operation and provides up to 90 terajules (TJ) per day of gas from the Northern Territory to Mount Isa.[427]

424 This includes flexible thermal generation, demand response and renewable generation with storage.

425 AEMO, *2018 Gas statement of opportunities,* June 2018, p. 3.

426 Department of Industry, Innovation and Science, *Heads of Agreement – The Australian East Coast Domestic Gas Supply Commitment*, 3 October 2017.

427 AEMO, *2019 Gas statement of opportunities,* March 2019, p. 3.

- Demand for gas from gas powered generators has reduced by 54 petajoules (PJ) from 2017 to 2018. The installation of nearly 2,000 MW of new utility scale renewable generators and a large number of residential rooftop PV systems in 2018 was a key contributing factor. This trend is set to continue in the near term with over 7,000 MW of additional renewable generators either committed or under construction.[428]
- New projects such as Cooper Energy's Sole and Esso-BHP's West Barracouta are forecast to begin production in 2019 and 2021 respectively.[429]
- The introduction of the Australian Domestic Gas Security Mechanism continues to provide an incentive for LNG producers to ensure adequate domestic supply.[430]

AEMO notes that overall gas production is forecast to continue to increase in the near term to meet forecast demand.[431]

The Panel also notes that in April 2018, AEMO published its final report into the review of the market parameter settings[432] in the Short Term Trading Market (STTM) and Declared Wholesale Gas Market (DWGM). AEMO determined that the STTM parameter set was sufficient to allow revenue recovery for new investments, and provided adequate protection in the STTM. Hence, the STTM parameter set remained unchanged. In relation to the DWGM market parameter set, AEMO stated that it failed to provide adequate risk protection to market participants buying gas. Therefore, AEMO proposed to reduce the cumulative price threshold value from $1,800/GJ to $1,400/GJ. According to AEMO, this will allow the revised parameter set to provide adequate protection to market participants buying gas, while minimising the impact on market efficiency and allowing adequate revenue recovery for new investments. AEMO will conduct a formal consultation under Part 15B of the National Gas Rules to implement the change with effect from 1 July 2020.[433]

In March 2018, the AEMC published a final report for the review of the application of gas pipeline capacity trading reforms in the Northern Territory (NT). This review, undertaken at the request of the COAG Energy Council, recommended that pipeline capacity trading reforms developed by the AEMC for the east coast gas market should apply in the NT. The reforms would make it cheaper and easier to move gas around the NT market and also the connected east coast market.[434] In July 2018, the AEMC also published its final report for the review into the regulation of covered pipelines. The report includes 32 recommendations for the economic regulation framework for full and light regulation of (covered) pipelines, which will make it easier and cheaper to move gas to where it is most valued.[435]

428 Ibid, p. 27.

429 Ibid, p. 5.

430 Ibid, p. 13-14.

431 Ibid, p. 38.

432 For the Short Term Trading Market parameter settings include: market price cap, administered price cap, cumulative price threshold, cumulative price threshold horizon and minimum market price. For the Declared Wholesale Gas Market parameter settings include: value of lost load, administered price cap, cumulative price threshold, cumulative price period and minimum market price.

433 AEMO, *Gas market parameter review 2018*, final report, April 2018, p. 2.

434 For more information see: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-application-of-capacity-trading-refo

435 For more information see: https://www.aemc.gov.au/markets-reviews-advice/review-into-the-scope-of-economic-regulation-appli

In March 2018, AEMO published the *2018 Victorian gas planning report update* that provides a supply and demand, and pipeline capacity adequacy assessment for the Victorian gas Declared Transmission System over the next five years.[436] The key findings of the report were:[437]

- Gas supply forecasts provided to AEMO by participants show that gas production, due to the depletion of offshore gas fields, is forecast to reduce further in 2022.
  - Without additional gas supply, there is a potential shortfall in meeting annual Victorian gas consumption from 2022.
  - Without additional gas supply, there is a potential shortfall in meeting annual Victorian gas consumption from 2022.
  - Producers have advised AEMO that, by 2022:
    - Gippsland annual production is forecast to reduce to 38 per cent below the 2018 production forecast. Maximum daily production capacity is forecast to reduce by 50 per cent compared to the 2018 forecast.
    - Port Campbell annual production is forecast to reduce by 68 per cent from the 2018 forecast, due to some offshore fields ceasing production. Maximum daily production capacity is forecast to reduce by 76 per cent.
  - Gas supply from Victoria to South Australia and New South Wales is expected to reduce, due to the forecast decline in Victorian gas production. Supply to these states is expected to reduce more during winter, due to inventory limitations on gas stored at the Iona Underground Gas Storage facility.
- Participants are currently investigating additional sources of gas supply including peak day capacity. Options include increased production and storage capacity, additional pipeline import capacity into Victoria, and a liquefied natural gas import terminal.

Further, in November 2018, the AEMC received three rule change requests from the Victorian Minister for Energy Environment and Climate Change to amend the National Gas Rules.[438] These rule change requests follow from the AEMC's July 2017 final report for the *Review of the Victorian declared wholesale gas market*, which identified a number of issues with the DWGM.[439] The rule change requests propose to introduce the following changes:

- the introduction of a clean and simple wholesale gas prices for the DWGM
- establishing a forward trading exchange which will make it easier for buyers and sellers to trade gas and lock in a future price
- improving the allocation and trading of pipeline capacity rights.

The AEMC has not yet initiated this rule change request.

436 For more information, see: https://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report

437 AEMO, *2018 Victorian gas planning report update,* p. 3.

438 For more information, see: https://www.aemc.gov.au/rule-changes/dwgm-simpler-wholesale-price; https://www.aemc.gov.au/rule-changes/dwgm-forward-trading-market and https://www.aemc.gov.au/rule-changes/dwgm-improvement-amdq-regime

439 For more information, see: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-victorian-declared-wholesale-gas-mar

4.4 Work underway on reliability

The Panel notes that various projects are currently underway that relate to the reliability of the power system. A summary of these projects is provided below.

4.4.1 Retailer Reliability Obligation

In October 2017, the ESB provided the COAG Energy Council with the initial advice on changes to the NEM and legislative framework. The proposed National Energy Guarantee aimed to combine reliability outcomes and emissions targets to achieve a single energy price that guides investment and operation in the lowest cost.[440]

In October 2018, the COAG Energy Council agreed to progress the reliability component of the National Energy Guarantee - the Retailer Reliability Obligation. The Retailer Reliability Obligation mechanism aims to incentivise retailers, and other large users, to invest in dispatchable electricity generation in the NEM regions, where it is expected there will be a gap between generation and forecast peak demand.[441]

The Retailer Reliability Obligation is a long term solution to help drive towards a reliable electricity supply. If a generation gap is forecast, liable entities will be required to demonstrate they can meet their share of peak demand, for example, by having firm on-demand contracts related to the purchase or sale of electricity from the wholesale market.

On 19 December 2018, the COAG Energy Council agreed to the final draft bill of NEL amendments, which will give effect to the Retailer Reliability Obligation, as presented by the ESB. The ESB will progress a final package of rules to be brought to Council for approval in the first half of 2019 to facilitate commencement of the obligation by 1 July 2019.[442]

4.4.2 Reliability Panel review of reliability standard and settings 2018

On 30 April 2018, the Panel published a final report on the reliability standard and settings in the national electricity market.[443] The standard and settings support efficient generation and operational decisions and provide an important 'price envelope' protecting market participants from exposure to excessive high and low prices. This is essential to maintaining the integrity of the market.

The reliability standard and settings focus on the future performance of the NEM. Their purpose is to:

- Establish the level of reliability consumers can expect from key aspects of the physical system (generators and interconnectors), by setting the reliability standard.

440 COAG Energy Council, *National Energy Guarantee*, accessed on 20 December 2018, at: http://www.coagenergycouncil.gov.au/publications/energy-security-board-update

441 COAG Energy Council, *Meeting Communique*, 26 October 2018.

442 COAG Energy Council, *Meeting Communique*, 19 December 2018.

443 For more information, see the project page: https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018

- Protect the long term integrity of the market by limiting the extent to which wholesale prices can rise and fall, to limit market participants' exposure to prices that could threaten the financial viability of a prudent market participant.
- Allow for sufficient investment to provide electricity to the agreed reliability standard.

The Panel recommended that the reliability standard and settings for the NEM remain unchanged for the period from 1 July 2020 to 1 July 2024 (see Table 4.2).

Table 4.2: **Reliability standard and settings**

COMPONENT AND PURPOSE	CURRENT LEVEL AND RECOMMENDED LEVEL FROM 1 JULY 2020
Reliability standard: Expresses the level of reliability sought from the NEM's generation and transmission inter-connector assets.	A maximum expected unserved energy in a region of 0.002 per cent of the total energy demanded in that region for a given financial year.
Market price cap: Seeks to maintain the overall integrity of the NEM by limiting market participants' exposure to temporary high prices which could threaten the financial viability of prudent market participants. The market price cap should be set at a level such that prices over the long term incentivise enough new investment in generation so the reliability standard is expected to be met. The market price cap is the maximum bid (and therefore settlement) price that can apply in the wholesale market.	$14,200/MWh ($2017)
Cumulative price threshold: Seeks to maintain the overall integrity of the NEM by limiting market participants' exposure to sustained high prices which could threaten the financial viability of prudent market participants. The cumulative price cap should be set at a level such that prices over the long term incentivise enough new investment in generation so the reliability standard is expected to be met. The cumulative price threshold caps the total market price that can occur over seven consecutive days.	$212,800 ($2017)
Administered price cap: Seeks to maintain the overall integrity of the NEM by limiting market participants' financial exposure to	$300/MWh

COMPONENT AND PURPOSE	CURRENT LEVEL AND RECOMMENDED LEVEL FROM 1 JULY 2020
sustained high prices, while maintaining incentives for participants to supply energy during the period of trading after the cumulative price threshold is exceeded, i.e. an administered price period. The administered price cap is the price 'cap' that applies when the cumulative price threshold is exceeded.	
Market floor price: Prevents market instability by imposing a negative limit on the total potential volatility of market prices in any trading interval, while allowing the market to clear during low demand periods. The market floor price should be set at a level that does not interfere with generators being able to differentiate themselves according to the value they place on being dispatched by bidding at negative prices during periods of excess generation.	-$1,000/MWh

Source: Reliability Panel, *Review of reliability standard and settings 2018,* April 2018.

4.4.3 Reliability frameworks review

On 26 July 2018, the AEMC published the final report of its *Reliability frameworks review*.[444] This review has looked at ways to deliver a reliable power system.

This report makes a series of recommendations to implement and develop mechanisms in the NEM aimed at supporting reliable outcomes for consumers at lowest cost. The key recommendation areas are:

- Improving the information available to the market so decisions made by market participants, the operator, regulators and policy-makers are better-informed.
- Integrating demand into the wholesale market to support an active demand side.
- Improving wholesale market outcomes and signals to underpin efficient operational decisions.

This report also concludes a number of Finkel Panel recommendations concerning reliability that were directed to the AEMC.[445] Specifically:

444 For more information, see the project page: https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review

445 For more information on the *Independent review into the future security of the national electricity market (Finkel Review)*, see: https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-blueprint-for-the-future-2017.pdf

- The Commission has recommended a package of changes to facilitate demand response in the wholesale market.
- The need for a strategic reserve is being considered through the *Enhancement to the RERT* rule change process.
- The Commission has concluded that a US-style day-ahead market would not be suitable for improving reliability outcomes in the NEM.

4.4.4 Demand response mechanism

On 15 November 2018, the Commission published a consultation paper inviting stakeholder feedback on the key issues raised in several rule change requests that seek to introduce a mechanism for wholesale demand response in the NEM.[446]

These rule change requests follow the Commission's consideration of wholesale demand response in its *Reliability frameworks review*. The final report for this review recommended integrating more demand response in the wholesale market by:

- enabling demand response aggregators and providers to be recognised on equal footing with generators in the wholesale market and so offer wholesale demand response transparently into the market.
- implementing a voluntary, contracts-based short term forward market that would allow participant-to-participant trading of financial contracts closer to real time. This will provide the demand side with more opportunities to lock in price certainty, making it easier for large demand side consumers to engage in the wholesale market and demand response in response to expected wholesale prices.
- allowing consumers to engage multiple retailers / aggregators at the same connection point (multiple trading relationships). This will promote competition between retailers, support new business models for demand response and provide consumers with greater opportunities to engage in wholesale demand response with parties other than their incumbent retailer.

4.4.5 Generator three-year notice of closure rule

On 8 November 2018, the Commission made a final rule that requires large electricity generators to provide at least three years' notice to the market before closing.[447] This information will help market participants respond to possible future shortfalls in electricity generation, for example by building replacement capacity. This will help to support the reliability of the power system. The rule is based on one of the recommendations in the Finkel Panel review.[448]

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446 On 31 August 2018, the Public Interest Advocacy Centre, Total Environment Centre and the Australia Institute submitted a rule change request seeking to introduce a mechanism for wholesale demand response. This mechanism would allow third parties to offer demand response into the wholesale electricity market in a transparent, scheduled manner. On 18 October 2018, the Australian Energy Council submitted a rule change request seeking to introduce a register for wholesale demand response. This proposal would introduce an obligation for retailers to negotiate in good faith with third parties looking to provide wholesale demand response through a register. On 21 October 2018, the South Australian Government submitted a rule change request seeking to introduce a mechanism for wholesale demand response. It also proposes to introduce a separate, transitory market for wholesale demand response.

447 For more information, see the project page: https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure

448 For more information on the *Independent review into the future security of the national electricity market (Finkel Review)*, see:

The rule requires generators to advise AEMO of the expected closure year for all their scheduled and semi-scheduled generation units. It also requires generators to give AEMO at least three years' notice of their intention to permanently close a generating unit unless they are granted an exemption by the AER. The provision of this information to the market will assist in managing the market impacts of the retirement of coal-fired generators as they reach the end of their economic lives.

AEMO must maintain an up-to-date list of expected closure dates for generating units on its website. AEMO must also consider and include information about generator exits as part of its annual long term forecast process, the ESOO.

The Commission has recommended new civil penalties, enforced by the AER, if generators fail to comply with the new obligations.

The rule also provides the Panel with discretion to identify specific energy constraint scenarios to be included for study for the purposes of preparing the *Energy Adequacy Assessment Projection* (EAAP). This will broaden the nature of input AEMO receives in considering possible energy constraint scenarios and their impact on generation adequacy.

To support implementation of the new rule, the AER will be required to develop a guideline by 31 August 2019, specifying how generators should provide information about closures to AEMO and when exemptions may apply. In the meantime, generators can voluntarily provide information about closures to AEMO.

4.4.6 Enhancement to the RERT rule

On 7 February 2019, the Commission published a draft determination for the AEMO's rule change request that seeks broad changes to the RERT.[449] The draft determination sets out a series of changes that will provide AEMO with the flexibility it needs to use the RERT to manage the transition in the power system, while doing so at least cost to consumers.

The draft rule enhances the RERT framework, by embedding it clearly within the reliability framework, providing AEMO with flexibility about how and when to purchase standby electricity supplies for events like extreme heatwaves, while keeping costs to consumers as low as possible.

The Commission has made a draft rule that is a more preferable rule. The draft rule will allow AEMO to procure reserves for the 2019/20 summer through the new framework. Some key features of the draft rule include:

- clarifying that the trigger for procuring RERT is a breach of the reliability standard
- increasing the time for AEMO to procure reserves from nine months to 12 months ahead of when it considers reserves will be needed
- introducing a price guide on the RERT so that the price paid for RERT is less than the cost of involuntary load shedding

https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-blueprint-for-the-future-2017.pdf

449 For more information, see the project page: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

- encouraging the market to be the primary means by which reliability is delivered by strengthening the provisions that govern that the RERT only includes out-of-market reserves
- improving transparency of how the RERT works and how much it costs.

4.4.7 Coordination of generation and transmission investment review

On 21 December 2018, the AEMC published the final report of its *Coordination of generation and transmission investment review*.[450]

This report recommends a comprehensive reform package that better coordinates investment in renewable generation and transmission infrastructure, facilitating transmission and generation in the right place at the right time at an efficient cost. The recommendations complement each other and include:

- directly link investment decisions by transmission businesses to the AEMO's ISP, to streamline regulatory approval processes for these strategic projects
- streamline the cost-benefit assessment for new transmission by removing duplication from the process
- manage congestion so the cheapest power can get to consumers. This involves implementing phased reforms to change how generators access and use the network, starting with dynamic regional pricing
- allow generators to pay for transmission infrastructure in exchange for access to it – which means generators can influence and have control over transmission planning decisions, leading to better coordination of generation and transmission investment
- examine how to better align the costs of transmission, especially interconnectors, with those that benefit from the investment
- facilitate renewable energy zones through generators funding of transmission infrastructure
- make it easier for large-scale storage systems to connect to the network by creating a new registration category to support seamless integration.

The AEMC's recommendations for better coordination of generation and transmission investment, outlined above, complement the recommendations made by the ESB to the COAG Energy Council in December 2018 on how to "convert the ISP" into an "actionable strategic plan", and how the ISP projects could be delivered as quickly as possible.[451] The AEMC's recommendations provide further detail on how the ESB's recommendations can be implemented.

The AEMC recommends that the reforms be implemented in stages, to enable delivery of the *2018 ISP* in the timeframes identified by AEMO. The final report includes an implementation work plan, with the final stage of reforms completed in 2023.

450 For more information, see the project page: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

451 For more information, see: ESB, *Integrated system plan; Action plan*, December 2018.

4.4.8 Coordination of generation and transmission investment implementation – access and charging

In February 2019, the AEMC started the second *Coordination of generation and transmission investment* review. Two key recommendations from the inaugural *Coordination of generation and transmission investment* final report will be progressed through this second review. These are:

- reforms to the way generators access and use the transmission network
- a review of the charging arrangements which enable transmission businesses to recover the costs of building and maintaining transmission infrastructure, both within and between regions.

On 1 March 2019, the AEMC published a consultation paper to commence the C*oordination of generation and transmission investment implementation – access and charging* review. The AEMC considers that the current access regime needs to evolve to allow the risk and cost of generation investment to evolve to better complement planning and investment in transmission. The purpose of proposed reforms is to improve the coordination between the generation and transmission sector. This includes considering how these reforms will better allow generators to coordinate on their connections, including the provision of certain services such as system strength. This longer-term work program will also consider issues related to system losses more holistically.

Over the course of 2019 the AEMC will develop draft rule change requests in relation to access and charging reforms. This timeframe will allow the Commission to undertake substantial consultation on this complex review, through the publication of papers, as well as establishing a technical working group and holding public forums.

4.4.9 Reporting on aggregate generation capacity for MT PASA rule

On 24 May 2018, the AEMC made a final rule to improve the clarity and consistency of information AEMO provides to signal whether electricity supply is projected to meet demand in the medium-term.[452]

The final rule removes the requirement that AEMO consider network constraints when reporting aggregate generation capacity for each region as part of the medium-term projected assessment of system adequacy, or MT PASA. Network constraints will continue to be considered in other relevant MT PASA outputs.

4.4.10 Reinstatement of the long notice RERT rule

On 21 June 2018, the Commission made a final rule which promotes reliability in the NEM by increasing the lead time available for AEMO to procure out-of-market reserves through the RERT, to nine months ahead of a projected shortfall. This effectively reinstates what was known as the long-notice RERT.[453]

452 For more information, see the project page: https://www.aemc.gov.au/rule-changes/reporting-of-aggregate-generation-capacity-for-mt

453 For more information, see the project page: https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader

The key features of the final rule are:

- an increase in the procurement lead time available to AEMO to procure the RERT from 10 weeks to nine months ahead of a projected reserve shortfall (effectively reinstating the long-notice RERT) with effect from 13 July 2018
- a transitional rule that amends the RERT guidelines made by the Panel to reflect the reinstatement of the long-notice RERT
- a transitional rule that requires AEMO to amend its RERT procedures to reflect the final rule and amended guidelines.[454] The rule requires AEMO to consult on the proposed amendments to its RERT procedures for a minimum of two weeks prior to the revised procedures taking effect.

The final rule promotes reliability since AEMO is able to, if there is a shortfall, have access to a broader range of reserves than it otherwise would. Reinstating the long-notice RERT may also improve efficiency of the procurement process and put downward pressure on RERT costs, if it is needed.

4.4.11 Establishing values of customer reliability rule

On 5 July 2018, the Commission made a final rule to make the AER responsible for calculating values of customer reliability (VCR) estimates.[455] VCR estimates play an important role in balancing the need to deliver secure and reliable electricity supplies and maintain reasonable costs for electricity consumers. This rule requires AER to develop a VCR methodology, and calculate the first VCR estimates under that methodology, by 31 December 2019.

The final rule will help remove unnecessary duplication and decrease the administrative burden both for bodies calculating VCRs, and for stakeholders contributing to their development. It does this by assigning responsibility to one body to develop the VCR methodology and calculating VCR estimates. Transparency, accountability and certainty will be improved by establishing timeframes, a VCR objective, and an overarching process for developing and reviewing the VCR methodology that will be used to calculate VCR estimates, along with publication requirements.

In October 2018, the AER has published a consultation paper for its *Values of customer reliability* review.[456] The review is expected to be completed by December 2019. The AER has also established a Consultative Committee that provides its views to the AER on matters relating to VCR. The Panel is a member of this Committee.

4.4.12 AEMO/ARENA demand response trial

On 19 May 2017, AEMO and ARENA announced a joint demand response pilot program for the NEM that involves the procurement of demand response reserves that would sit within

454 AEMO published the amended *Procedure for the exercise of Reliability and Emergency Reserve Trader* on 13 July 2018.

455 For more information, see the project page: https://www.aemc.gov.au/rule-changes/establishing-values-of-customer-reliability

456 For more information, see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability-vcr

the RERT framework (i.e. provide short-notice reserves).[457] The program began on 1 December 2017 and will run for three years. The program's aim is to trial a strategic reserve model (referencing international market designs) for reliability or emergency demand response, to inform future market design as well as contributing to reserves for summer.[458]

ARENA will provide, over a period of three years, up to $22.5 million of funding for projects outside New South Wales, and ARENA together with the New South Wales Government (on a 50-50 basis) will provide up to $15 million of funding for New South Wales projects. Those demand response service providers that were successful through the ARENA funding process receive the ARENA capital-funding grant in the form of availability payments over three years and are required to sign onto the AEMO short-notice RERT panel and be available for short notice RERT if requested. Providers will also receive usage payments of up to $1,000/MWh, if activated. If activated, the market would pay for the activation charges.[459]

This program has delivered 141 MW in year 1, and will deliver 190 MW in year 2 and 202 MW in year 3, across New South Wales, Victoria, and South Australia. This capacity complements 226 MW of non-market generation and 741 MW of industrial demand response contracted by AEMO under the long-notice RERT arrangements for summer 2017/18.[460]

The trial consists of two standardised products: a 60-minute product and a 10-minute product. ARENA has stated that seven of its 10 providers have offered an under 10-minute product, while three have offered to provide reserves under the 60-minute product - the latter are typically residential consumers with behavioural demand response, which requires a longer lead time.[461]

4.5 Relevant government initiatives

The Panel notes there have been a number of recent government interventions relevant to the reliability, as well as security, of the system.[462] These are summarised below.

4.5.1 Queensland

The Queensland Government's initiatives include:

- **Return Swanbank E gas-fired power station to service:** The Queensland Government directed Stanwell to return its 386 MW Swanbank E Power Station to service in late 2017.
- **CleanCo:** In August 2018, the Queensland Government announced the creation of a new publicly owned 'CleanCo' clean energy generator, which intends to address energy reliability and put downward pressure on electricity prices in Queensland.[463] CleanCo is expected to transform intermittent renewable energy into a firm financial product,

457 For more information, see: https://arena.gov.au/funding/programs/advancing-renewables-program/demand-response/
458 AEMC, *Enhancement to the Reliability and Emergency Reserve Trader,* options paper, 18 October 2018. p. 13.
459 Ibid.
460 Ibid.
461 ARENA-AEMO joint submission to *Reliability frameworks review* - directions paper, p. 6.
462 This sub-section of the report is both relevant for the Reliability and Security chapters.
463 For more information, see: https://www.treasury.qld.gov.au/growing-queensland/queenslands-new-cleanco/

offering retailers and customers firm base load power, backed by the state's low emission and renewable assets. According to the Queensland Government, CleanCo will have a strategic portfolio of low and no emission power generation assets, and will build, construct, own and maintain renewable energy generation. This includes the trading rights to a foundation portfolio of existing renewable and low emission energy generation assets such as the Wivenhoe pumped storage hydro plant, Swanbank E, Barron Gorge, Kareeya and Koombooloomba Power Stations.[464] CleanCo is expected to be trading in the NEM by mid-2019, subject to receiving regulatory approvals.

- **North Queensland plan:** The Queensland Government has committed:[465]
    - $150 million to develop strategic transmission infrastructure to link energy projects in North and North-West Queensland.[466]
    - $100 million equity injection into SunWater and reinvest dividends to deliver improvement works at the Burdekin Falls Dam, and further $100 million to fund a 50 MW hydro-electric power station at the dam.[467]
- **Reverse Auction:** The Queensland Government is supporting up to 400 MW of diversified renewable energy, including up to 100 MW of energy storage, through a reverse auction.[468]

4.5.2 New South Wales

The relevant New South Wales Government initiatives include:

- **Transmission Infrastructure Strategy:** In November 2018, the *New South Wales Transmission Infrastructure Strategy* was published.[469] In the document, the New South Wales Government stated it will provide a funding guarantee that will allow TransGrid to bring forward by up to nine months the final delivery of the following projects:
    - Upgrade the existing Victoria-New South Wales Interconnector
    - Upgrade the Queensland-New South Wales Interconnector
    - A new South Australia-New South Wales Interconnector
    - New transmission from Snowy Hydro to Bannaby, via Wagga Wagga.
- **Regional Community Energy:** In August 2018, the New South Wales Government announced the $30 million clean energy program. The program is designed to enable communities across the state to build their own local clean energy projects. The program targets regional areas and is composed of three streams:
    - Grants for community energy projects that are innovative or create dispatchable renewable energy and benefits to the local community.

464 The State of Queensland (Queensland Treasury), *CleanCo Fact Sheet*, accessed on 15 November 2018, at: https://s3.treasury.qld.gov.au/files/CleanCo-fact-sheet.pdf

465 For more information, see: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland

466 Subject to a feasibility study.

467 Subject to completion of a business case.

468 For more information, see: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland

469 Department of Planning and Environment, *NSW transmission infrastructure strategy*, November 2018, p. 10.

- Funding for up to five community energy hubs that improve household and small business access to expert energy advice and to initiatives such as bulk buys to help regional communities reduce bills.
- Funding to regional and remote communities to install emergency backup systems for key evacuation locations, such as a town hall, to improve resilience while also reducing energy costs during regular operations.

These community projects are expected to reduce pressure on the grid and improve energy security in the state.[470]

- **Emerging Energy Program:** In October 2018, the New South Wales Government announced the $55 million Emerging Energy Program. The program aims to encourage large-scale projects to provide electricity on demand and improve energy security and reliability in New South Wales. The program will promote the diversification of electricity supply, via emerging technologies and renewable sources. Eligible projects must demonstrate the ability to provide dispatchable or on-demand energy to help meet the state's energy needs. Projects must also demonstrate the ability to manipulate output (or load) in response to one or more of the wholesale energy or ancillary service price signals in the NEM. Funding will be provided to commercialise these projects, as well as support pre-investment studies.[471]
- **Smart Energy for Homes and Businesses:** The program is designed to bring together smart energy technologies in New South Wales homes and businesses to form a 'distributed' power plant with a demand response capability of up to 200 MW, to help manage peak demand on the grid. The $50 million program will reward smart energy homes and businesses for feeding their energy into the grid or reducing energy usage. Customers who invest in smart energy technologies, such as solar batteries or smart air-conditioners, and agree to contribute to the grid when this is needed will be eligible to receive a New South Wales Government incentive of up to $1,000. A demand response capability is expected to improve energy security in the region.[472]

4.5.3 Victoria

The Victorian Government has announced the following initiatives:

- **Energy Storage Initiative:** In 2017, the Victoria Government announced the $25 million Energy Storage Initiative, and in March 2018, two projects to build commercially-ready battery storage in western Victoria were selected: Ballarat Energy Storage and Gannawarra Energy Storage System (GESS).
  - Ballarat Energy Storage is a 30MW/30MWh large-scale, grid-connected battery located at the Ballarat Area Terminal Station.[473] ARENA and the Victorian Government jointly provided $25 million in funding for the project.[474] The battery will store energy

470 For more information, see: https://www.nsw.gov.au/your-government/the-premier/media-releases-from-the-premier/clean-energy-funding-to-reduce-power-bills/ and https://energy.nsw.gov.au/renewables/clean-energy-initiatives/regional-community-energy

471 For more information, see: https://www.energy.gov.au/news-media/news/emerging-energy-program-nsw-business

472 For more information, see: https://energy.nsw.gov.au/renewables/clean-energy-initiatives/smart-energy-homes-and-businesses

473 For more information, see: https://arena.gov.au/projects/ballarat-energy-storage-system/

at times of relatively low value and use it at times of relatively high value. The project will also examine providing other grid services such as FCAS, specifically, a fast frequency response. According to ARENA, this project may demonstrate how batteries can help provide grid stability and support on a congested transmission terminal, reducing the need to expand the substation. The battery will be capable of powering 20,000 homes for an hour.

- The GESS is a 25MW/50MWh lithium-ion battery to be co-located with the 60 MW Gannawarra Solar Farm located west of Kerang in north-western Victoria.[475] Similarly to Ballarat Energy Storage, ARENA and the Victorian Government jointly provided $25 million in funding for the project.[476] Among other potential benefits, the project may demonstrate how an existing solar farm can be retrofitted with battery storage. Further, according to ARENA, the battery could assist by reducing curtailment of future renewable energy generation on what is a relatively constrained line in the Victorian electricity system. This may support higher levels of renewables in the region by reducing or controlling peak loading on these circuits.[477]

- **Solar Homes program:** In August 2018, the Victoria Government announced the $68 million Solar Homes program. Under the program, eligible[478] Victorians will be able to install a solar panel system and get half of the cost back via a 50 per cent rebate, up to a maximum rebate of $2,225. The rebates are available for systems installed on/or after 19 August 2018.[479]

4.5.4 South Australia

Key programs being designed and delivered by the South Australian government include:

- **$100 million Home Battery Scheme:** From October 2018, 40,000 South Australian households can access $100 million in State Government subsidies and $100 million in loans to pay for the installation of home battery systems.[480]
- **$50 million Grid Scale Storage Fund:** Grants are provided to support development of new energy storage technologies to back up renewables and enhance reliability of South Australia's electricity system.[481]
- **$150 million Renewable Technology Fund:** The fund was designed to accelerate the deployment of renewable technologies. The first investment from the Fund was

474 The total project value is $35.10 million.

475 For more information, see: https://arena.gov.au/projects/gannawarra-energy-storage-system

476 The total project value is $34.27 million.

477 ARENA, *Gannawarra Energy Storage System (GESS),* accessed on 15 November 2018, at: https://arena.gov.au/projects/gannawarra-energy-storage-system/

478 The 50 per cent rebate on solar panel systems will be available to Victorians with a household income of up to $180,000 who live in their own home valued at up to $3 million. According to the Victorian Government, this means almost nine out of 10 Victorians who own their own house are eligible.

479 For more information, see: https://www.solar.vic.gov.au/Solar-Panel-Rebate

480 For more information, see: http://www.energymining.sa.gov.au/energy_implementation/home_battery_scheme

481 SA State Budget 2018/19, accessed on 15 November 2018, at: https://statebudget.sa.gov.au/#Lower_Costs

Hornsdale Power Reserve - the world's largest lithium ion battery (100 MW, 129 MWh) officially launched in South Australia on 1 December 2017.[482]

- **Virtual Power Plant:** The South Australian government is developing a network of potentially 50,000 home solar PV and Tesla Powerwall battery systems across South Australia. The first 100 systems have been installed on SA Housing Trust homes. Installation of a further 1,000 systems on SA Housing Trust homes will test these energy systems operating together as a virtual power plant. Subject to the success of the trials, the full program will be rolled out to a further 24,000 public housing properties and 25,000 private properties from mid-2019.[483]
- **Demand Management Trials Program:** The program allocates $30 million over three years towards trials aiming to establish mechanisms to reward consumers for demand flexibility and changing their consumption patterns to reduce peak demand and lower energy system costs.[484]
- **$4 million investment into South Australia and New South Wales interconnector:** Direct assistance of $4 million will be provided in 2018/19 to enable transmission network operators to commence early works to support delivery of further interconnection between the eastern states and South Australia. The government will also provide a finance guarantee of up to a further $10 million for this purpose.[485]

482 For more information, see: https://virtualpowerplant.sa.gov.au/sites/default/files/public/attachments/energy-investment-guidelines.pdf

483 For more information, see: https://virtualpowerplant.sa.gov.au/virtual-power-plant

484 SA State Budget 2018/19, accessed on 15 November 2018, at: https://statebudget.sa.gov.au/#Lower_Costs

485 SA State Budget 2018/19, accessed on 15 November 2018, at: https://statebudget.sa.gov.au/#Lower_Costs

5 SECURITY REVIEW

This chapter describes:

- the Panel's consideration of the system security performance of the NEM in 2017/18
- projections of system security and emerging issues
- relevant work addressing system security issues in the NEM.

The Panel notes the following key system security trends and outcomes:

- **Meeting frequency requirements:** The frequency performance of the NEM showed mixed performance in 2017/18. During the review period, the frequency operating standard (FOS) was only partly met in the mainland and was not met in Tasmania. The FOS consists of several different measures of frequency performance, only some of which were met. The elements of the FOS relevant to normal operation of the power system include:
  - power system frequency is required to be kept within specific bands, for normal operation. The current requirement is that for 99 per cent of the time, power system frequency must be maintained within the range of 49.85 – 50.15Hz (the normal operating frequency band), over any 30 day period, and
  - if there is a disturbance to power system frequency, frequency must be returned to the normal operating frequency band within a set timeframe. The current requirement is that during normal operation, if the power system frequency deviates outside the normal operating frequency band, it must be returned to the normal operating frequency band within five minutes.

  In 2017/18, one element of the FOS was not met in the mainland and both elements were not met in Tasmania:

  - While the mainland frequency remained within the normal operating frequency band more than 99 per cent of the time for each month of the reporting period, there were 50 events where system frequency took longer than five minutes to return to the normal operating frequency band, and therefore did not meet all the requirements of the standard.[486]
  - In Tasmania, frequency performance did not meet either of the FOS requirements[487], with system frequency outside of the normal operating frequency band for more than 99 per cent of the time for 11 months in 2017/18. Further, there were 295 events where frequency took longer than five minutes to be returned to the normal band.[488]

  In 2017/18, the aggregate amount of time spent outside the normal operating frequency band more than doubled for the mainland and also saw marked increases for Tasmania,

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486 AEMO, *Frequency and time error monitoring reports*, March 2018, March 2018, June 2018 and July 2018.

487 The current frequency operating standard for the NEM mainland and Tasmania defines different frequency boundaries that apply for different types of contingency events. This is due to the specific tolerances of Tasmanian generators to frequency variations and the intention at the time the standard was set to limit the cost of FCAS procurement.

488 Ibid.

as compared to 2016/17. Work underway to address the degradation of frequency performance is discussed further in this chapter.

- **Instances when the power system was not in a secure operating state:** In 2017/18, there was one instance where the power system was not in a secure state for greater than 30 minutes.[489] Over the past three years, this represents a significant decrease in the number of times secure operating limits were exceeded for greater than 30 minutes.[490]
- **Voltage limits:** Issues related to voltage control arose in South Australia and Victoria during the reporting period. In those states a need was identified for additional reactive support to maintain transmission system voltages within operational limits during minimum demand periods. AEMO is currently managing over voltages with short term de-energisation of high voltage lines, with de-energisation of individual 500 kV lines in Victoria occurring more than 40 times during light load periods, and five incidents of de-energisation of two 500 kV lines. In November 2018, AEMO had to de-energise three 500kV lines in Victoria for the first time.[491] These interventions may result in transmission network reliability risks and may also have market impacts. AEMO notified the market bodies that in future it will refrain from de-energisation of three 500 kV transmission lines in Victoria, and will instead direct generators to assist with voltage control. This is discussed further in the chapter together with the measures undertaken to address the voltage stability.
- **System Strength:** According to AEMO, levels of system strength are declining in north Queensland, south-west New South Wales, north-western Victoria and South Australia.[492] AEMO also identified a Network Support and Control Ancillary Services (NSCAS) gap in South Australia for system strength in the *2016 National Transmission Network Development Plan* (NTNDP).[493] To manage system strength in South Australia, AEMO uses the following instruments:
  - **Constraints:** AEMO continuously select resources to achieve security-constrained economic dispatch. This means that at all times, AEMO operates the system to balance supply and demand for power using the most economic resources available, consistent with maintaining a secure and reliable system. While AEMO applies economic principles to do this, power systems must operate in accordance with the laws of physics.[494] To secure grid operation in South Australia, AEMO uses constraints to restrict asynchronous generation to levels typically between 1,295 MW and 1,460

489 The Panel acknowledges that in the *2018 Health of the NEM*, the ESB reported that there were two such instances during 2017/18. However, since then AEMO undertook further analysis of the 2017/18 power system incidents and has determined that there was only one incident where the power system was not in a secure operating state for more than 30 consecutive minutes.

490 There were 11 such instances in 2016/17.

491 AEMO*, Victorian reactive power support project specification consultation report,* May 2018, p. 7. The Panel notes that the number of times high kV lines were de-energised has increased by the date of the publication of AEMO's Victorian reactive power support paper, as after May 2018 AEMO has used this instrument numerous times to address excessively high voltages in Victoria. For more information, see AEMO's market notices.

492 AEMO, *Integrated system plan*, July 2018, p. 62.

493 AEMO, *2016 National transmission network development plan*, December 2016, p. 8. AEMO confirmed this gap in subsequent updates in September 2017 and October 2017.

494 AEMO, *Advice to Commonwealth government on dispatchable capability*, September 2017, p. 2.

MW, to allow for a minimum number of synchronous generators being online for system strength requirements. The Panel understands there may be significant costs associated with the application of these system strength constraints in South Australia. Restricting output from asynchronous generators which often bid into the market at low prices, to allow synchronous generators with higher marginal costs to remain online during periods of low demand, impinges on the cost-efficient dispatch of generators and can increase wholesale prices. According to AEMO, in the 2017 calendar year the cumulative marginal value[495] of system strength constraints in South Australia was $4.75 million.[496]

- **Directions:** In 2017/18, there were 101 directions, compared to eight in 2016/17. Most of the directions (100 out of 101) that have occurred in 2017/18 were to ensure adequate system strength for secure operation of the South Australian power system.[497] Further, the proportion of time in which directions have been in place in the NEM has risen noticeably over the last year. For 2017/18, a direction was in place in the NEM on average approximately 20 per cent of the time, up from one per cent in 2016/17. According to AEMO, the cost[498] of the system strength directions was $7.05 million in Q2 2018 and $7.4 million in Q3 2018.[499] ElectraNet also stated that ongoing direction compensation costs are currently estimated to be approximately $34 million per annum in net terms (equivalent to around $3 million per month).[500] This excludes the broader impact of intervention pricing[501] on wholesale market prices through AEMO's direction process, which represents an additional cost ultimately borne by customers. In its *Addressing the system strength gap in SA* report, ElectraNet stated that the cost impact of intervention pricing on wholesale market outcomes as a result

495 Every dispatch interval, NEMDE provides the marginal value of every constraint used in the dispatch process. The marginal value of a constraint is the effect on total dispatch costs of alleviating that constraint by 1 MW. Summing the marginal values of a constraint over some a time period gives an indication of the cumulative marginal value of the constraint over the that time period. It is important to remember that the cumulative marginal value measures only the marginal cost of a constraint, and not the total cost. For example, in a given dispatch interval the marginal value of a constraint might be $10,000 per MW. This does not mean that alleviating the constraint by 10 MW will yield a benefit of $100,000 – the marginal cost of the constraint may fall rapidly as the constraint is alleviated, and may even fall to zero, which means the constraint is no longer binding.

496 AEMO, *NEM Constraint Report 2017 summary data*, July 2018.

497 In 2017/18, a direction in Queensland to maintain power system security was the only direction issued in the NEM other than for management of system strength in South Australia.

498 Based on Compensation Recovery Amount (provisional amount). Compensation Recovery Amount is recovered from the NEM for a direction. It is equal to the sum of the compensation amount paid by AEMO, independent expert fee and the interest amount. Interest is determined at the average bank bill rate between the settlement date corresponding to the direction date and the settlement date of the final determination week. AEMO, *NEM direction compensation recovery*, January 2015.

499 AEMO, *Quarterly energy dynamics*, Q3 2018, p. 7.

500 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 20. The cost of $34 million does not represent the total cost of directing generators in South Australia to ensure adequate system strength. It is also appropriate to take into account trading amounts that would otherwise be paid to those generators and wider impacts on wholesale market prices. This is discussed in more detail in Chapter 7 of the consultation paper for the AEMC's *Investigation into intervention mechanisms and system strength in the NEM*. Source: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

501 Where a direction has been issued, AEMO will apply intervention pricing in accordance with its Intervention Pricing Methodology. Intervention pricing is triggered when AEMO intervenes in the market by activating the RERT or issuing a direction. Intervention pricing determines the price at which the market clears during an AEMO intervention event, while compensation is a separate process and is paid only to certain parties – those who are directed to provide services and those who are affected (i.e. dispatched differently) due to the direction. Compensation is payable regardless of whether intervention pricing is implemented.

of issuing directions for system strength as at September 2018[502] exceeds $270 million.[503] This is additional to the impacts of constraining wind generation.[504]

5.1 System security assessment

Power system security is defined in the rules as the safe scheduling, operation and control of the power system on a continuous basis, in accordance with the power system security principles. These principles include AEMO maintaining the power system in a secure operating state[505] and returning the power system to a secure operating state as soon as it is practical to do so or in any event within 30 minutes following a contingency event or a significant change in power system conditions, including a major supply disruption.[506]

The performance of the power system is measured against various standards and guidelines that form the technical standards framework. The framework comprises a hierarchy of standards such as: system standards, access standards and plant standards.

The key technical parameters that need to be managed to maintain a secure and satisfactory operating state are power flows, system strength, voltage, frequency, the rate at which these quantities change and the ability of the system to withstand faults. Network limitations such as thermal limits[507], transient stability[508] and oscillatory stability[509] also need to be managed by the system operator.

This section examines whether key power system quantities, such as frequency and voltage, were maintained at the levels required in system performance standards during 2017/18. The section also examines performance stability of the power system in 2017/18. These system security performance indicators are explained in greater detail in appendix G.

502 While the basis on which this figure is calculated is not set out in the report, the Panel understands that it reflects the difference between spot prices as set by the intervention pricing run and prices produced by the dispatch run, averaged over the period April 2017 to September 2018.

503 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 21. While the basis of this $270 million figure is not set out in the ElectraNet report, the Panel surmises that it reflects the difference between spot prices as set by the "intervention pricing run" and prices produced by the "dispatch run" when system strength directions are in effect, averaged over the period from April 2017 to September 2018. If this is the case, it is likely that this figure represents an upper limit of the impact of intervention pricing on wholesale energy prices. This is because the market could be expected to self-correct at least to some degree if intervention pricing was not applied and prices were allowed to fall in response to additional generation coming online in response to a system strength direction. For example, in South Australia, removing intervention pricing and allowing the spot price to fall to reflect the supply demand balance that follows from the direction could be expected to prompt generators to rebid or withdraw from the market rather than pay to generate when prices fall to strongly negative levels. Secondly, higher spot prices typically do not translate immediately or directly into higher prices for consumers. This is because most retailers have hedge contracts with generators in order to manage wholesale price volatility. However, contract prices are negotiated having regard for expectations about future spot prices. As such, higher spot prices can be expected to put upward pressure on contract prices and thus wholesale energy costs. For more information, see: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

504 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 21.

505 The NEM is considered to be in a secure operating state if the power system is a satisfactory operating state and will return to a satisfactory operating state following a credible contingency in accordance with the power system security standards. The power system security standards are the standards (other than the reliability standard and the system restart standard) governing power system security and reliability of the power system.

506 For more information on these principles refer to rules clause 4.2.6.

507 For managing the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency.

508 For managing network flows to ensure the continued synchronism of all generators on the power system following a credible contingency.

509 For managing network flows to ensure the damping of power system oscillations is adequate following a credible contingency.

5.1.1 Instances when the system was not in a secure operating state

The power system is in a satisfactory operating state when:[510]

- it is operating within its technical limits (i.e. frequency, voltage, current etc. are within the relevant standards and ratings); and
- the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment.

The power system is in a secure operating state when it:[511]

- is in a satisfactory operating state; and
- will return to a satisfactory operating state following a single credible contingency event or protected event.

It is possible for secure technical limits to be exceeded for short durations. Clause 4.2.6(b)(1) of the NER requires AEMO to take all reasonable actions to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within 30 minutes.[512]

During 2017/18, there was one incident of the power system being operated outside its secure limits for greater than 30 minutes. Figure 5.1 shows the number of such instances from 2014/15 to 2017/18. The figure demonstrates that in 2017/18 there was a significant decrease in the number of times secure operating limits were exceeded for greater than 30 minutes. The power system has been operated outside its secure limits for greater than 30 minutes four times in 2014/15, seven times in 2015/16 and 11 times in 2016/17.

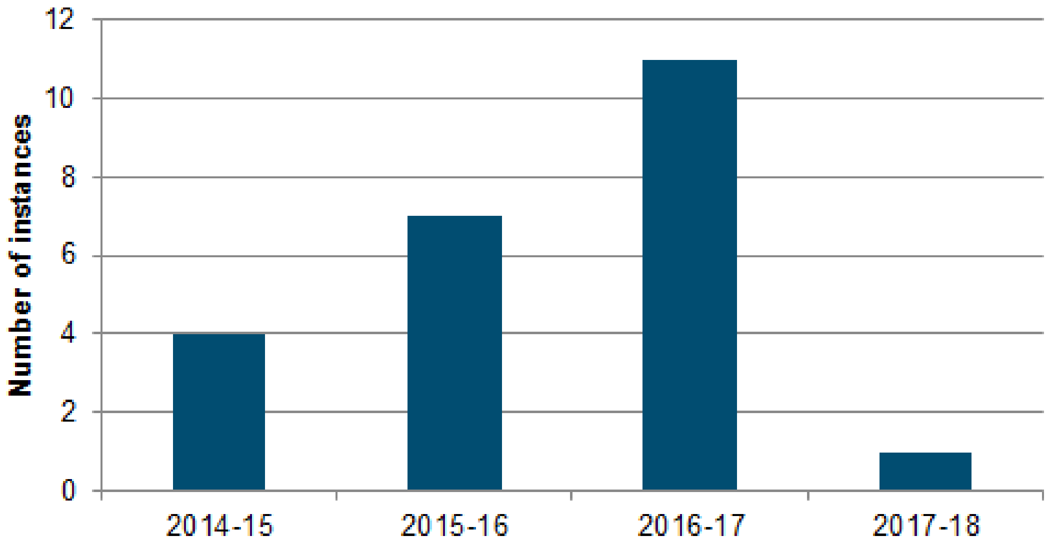
AEMO notes that there is no trend or pattern in the number of these events. The power system can become insecure for many reasons, which may or may not combine with other pre-existing or subsequently arising conditions or actions. According to AEMO, in the majority of cases where historically recovery has exceeded 30 minutes, AEMO could not have done anything differently to reduce the recovery time because of the particular combination of events that coincided. It is expected that the number of these events will continue to vary considerably over the years. The Panel considers that any apparent trends identified in the information set out in the figure below should be viewed in light of AEMO's comment.

510 Refer to clause 4.2.2 of the rules for the full definition of a satisfactory operating state.

511 Clause 4.2.4 of the rules.

512 In relation to frequency performance, there are additional requirements that are outlined in the frequency operating standard. Among other things, the standard provides the range of allowable frequencies and times for the stabilisation and recovery of the power system frequency following a frequency deviation. Frequency performance in 2017/18 in compared against the standard in section 5.1.2.

Figure 5.1: Number of times the operating system was not in a secure operating state for greater than 30 minutes



Source: AEMO.
Note: The Panel acknowledges that in the *2018 Health of the NEM*, the ESB reported that there were two such instanced during 2017/18. However, since then AEMO undertook further analysis of the 2017/18 power system incidents and has determined that there was only one incident where the power system was not in a secure operating state for more than 30 consecutive minutes.

In 2017/18, the event when the power system was not in a secure operating state for greater than 30 minutes followed switching actions taken to manage contingency overloads indicated after a transformer failure in Victoria on 18 January 2018.

The power system security issue was localised, and was identified by AEMO after a post-event review. Contingency analysis tools did not identify the issue at the time because the configuration of relevant equipment was not accurately reflected in AEMO's models. AEMO has since reviewed the modelling for all similar substations in the region.

Key details of the event are as follows:[513]

- At 15:19 on 18 January 2018, the Rowville No. 2 500 kV busbar, the Rowville A2 500/220 kV transformer, and the Rowville–South Morang line at South Morang tripped simultaneously.
- At 15:28 on 18 January the Loy Yang B No. 1 generating unit tripped from 530 MW.
- Approximately 600 MW of load was lost during this incident. The loss of load occurred in the distribution networks and no bulk supply points were disconnected from the transmission network. AEMO did not instruct any load shedding.

513 AEMO, *Trip of the Rowville No. 2 500kV Busbar and A2 500/220 kV Transformer on 18 January 2018*, incident report, March 2019, p. 6. NEM time (Australian Eastern Standard Time) is used in this report.

- The transmission equipment was returned to service in stages by 18:36 on 18 January 2018. The Loy Yang B No.1 generating unit was returned to service at 17:11 on 18 January 2018.

AEMO has concluded that:[514]

- The root cause of the disconnection of the busbar and transformer at Rowville was a faulty current transformer at Rowville, which was not isolated by AusNet Services in a timely manner.
- The trip of the Rowville–South Morang line occurred due to incorrect protection settings at South Morang. The protection settings have been corrected.
- Analysis performed subsequent to the conclusion of the incident indicated that, as a result of network switching requested by AEMO in response to this incident, the power system was not in a satisfactory operating state between 18 January and 1 February 2018.
- The trip of the Loy Yang B1 generating unit was caused by a generator governor issue and was not directly related to the issues at Rowville or South Morang.
- AEMO did not reclassify the loss of the Rowville–South Morang line for any fault at Rowville as a credible contingency in a timely manner.
- AEMO did not advise the market that constraints with interconnector terms on the Left Hand Side of a constraint equation (LHS) had been invoked during this incident.

5.1.2 Frequency

The alternating voltages and currents in an AC power system vary between negative and positive values in a sinusoidal manner. The number of complete cycles of these sinusoids that occur within one second is called the 'frequency' and is measured in Hertz (Hz).

Keeping the frequency of the system steady within defined boundaries is necessary to maintain the stability of the system. This is because generators typically require a narrow band of system frequency in order to operate safely and efficiently and maintain supply of power to the system. Changes in the system frequency can cause generators to disconnect from the system and create supply shortfalls.

The frequency requirements that AEMO must meet are set out in the frequency operating standard (FOS), which is defined in the NER and determined by the Panel.[515] The FOS incorporates a range of criteria that establish the frequency performance in the NEM for a range of operating conditions. The elements of the FOS relevant to normal operation of the power system include:

- the range of allowable frequencies in bands corresponding to the operating state of the power system. The current requirement is that for 99 per cent of the time, the power

514 Ibid, p. 4.

515 The frequency operating standards for the mainland and for Tasmania are available on the AEMC's website, at: http://www.aemc.gov.au/Australia-s-Energy-Market/Market-Legislation/Electricity-Guidelinesand-Standards. The Panel is currently in the second stage of its review of the frequency operating standard.

system is maintained within the range of 49.85Hz – 50.15Hz (the normal band) over any 30 day period, and

- times for the stabilisation and recovery of the power system frequency following a frequency deviation. The current requirement is that during normal operation, if the power system frequency deviates outside the normal band, it must be returned to the normal band within five minutes.

Controlling and maintaining a stable system frequency within a narrow range, close to 50Hz, increases the resilience of the system to non-credible contingency events. In the event of a severe non-credible or multiple contingency event, frequency that is already outside the normal frequency operating band may deviate even further from 50Hz, potentially leading to load shedding. The likelihood that the system will recover from the contingency event increases when frequency is within the normal operating band.

In the 2017 AMPR, the Panel concluded that as a general trend the number of normal band exceedances has increased over the past three years for both the mainland and Tasmania. The Panel's analysis of frequency control for the 2018 AMPR highlights the continuing degradation of frequency performance in the NEM. This trend is driven by various factors, including the marked reduction in primary frequency response of the NEM generation fleet.

The Panel has found that in 2017/18 one element of the FOS was not met in the mainland and both elements were not met in Tasmania:

- While the mainland frequency remained within the normal operating frequency band more than 99 per cent of the time for each month of the reporting period (as per the requirements of the FOS), there were 50 events where system frequency took longer than allowed in the FOS to be returned to the normal operating frequency band, and therefore that did not meet all the requirements of the standard.[516]
- In Tasmania, frequency performance did not meet both of the FOS requirements[517] ,with system frequency outside of the normal band for more than 99 per cent of the time for 11 months in 2017/18. Further, there were 295 events where frequency took longer than allowed in the FOS to be returned to the normal band.[518]

Table 5.1 summarises frequency performance against the standard in both the mainland and Tasmania from Q1 2017 to Q2 2018.

Table 5.1: Frequency performance from Q1 2017 to Q2 2018

REGION	FOS ELEMENT	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018
Mainland	Number of the 30-day	0	0	0	0	0	0

516 AEMO, *Frequency and time error monitoring reports*, March 2018, March 2018, June 2018 and July 2018.

517 The current frequency operating standard for the NEM mainland and Tasmania defines different frequency boundaries that apply for different types of contingency events. This is due to the specific tolerances of Tasmanian generators to frequency variations and the intention at the time the standard was set to limit the cost of FCAS procurement.

518 AEMO, *Frequency and time error monitoring reports*, March 2018, March 2018, June 2018 and July 2018.

REGION	FOS ELEMENT	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018
	periods (out of 12), when the normal band was exceeded for more than one per cent of the time[1]						
	Number of events not meeting the FOS	14	13	14	25	3	8
Tasmania	Number of the 30-day periods (out of 12), when the normal band was exceeded for more than one per cent[1]	10	10	12	10	7	9
	Number of events not meeting the FOS	67	47	49	36	57	153

Source: AEMO's *Frequency and time error monitoring reports*.
Note: 1 - Time during contingency events is excluded.

The Panel also notes that the AEMC and AEMO are currently progressing various regulatory measures, which are designed to address and improve the frequency control performance of the NEM. Specifically, AEMO and AEMC are working to introduce suitable interim measures to deliver sufficient primary frequency control in the NEM by Q3 2019. The AEMC will also work on a permanent mechanism to secure adequate primary frequency control by mid-2020.

Furthermore, there is evidence that market participants are utilising emerging technologies to provide new frequency control services.

This section sets out some of the ongoing frequency control issues in the NEM, then provides an overview of the various regulatory and commercial responses underway.

Overview of frequency control

Frequency control is a key element of power system security. To maintain a stable system frequency close to the nominal system frequency, AEMO must balance the supply of electricity into the power system against consumption of electricity at all times. When there is more generation than load, the frequency will tend to increase. When there is more load than generation, the frequency will tend to fall.

A number of components of the regulatory framework enable AEMO to manage frequency:

- ***Frequency control ancillary services (FCAS):*** FCAS are procured by AEMO to increase or decrease active power over a time frame that meets the requirements of the frequency operating standard. There are two types of FCAS: regulating and contingency. Regulating FCAS is used to correct small deviations away from 50 Hz during normal operation of the power system, while contingency FCAS are used to respond to larger frequency deviations due to disturbances such as a contingency event.[519]
- ***Generator technical performance standards:*** The levels of performance for equipment connected to the power system are set out in the performance standards for each connected generating system. In September 2018, the AEMC made the *Generator technical performance standards* rule, which, among other things, changes the requirements for connecting generators to manage their frequency performance in the face of certain frequency disturbances.[520] The rule also introduces new, more stringent requirements for generators to be capable of remaining connected to the power system following more severe frequency disturbances.[521]
- ***Emergency frequency control schemes:*** Emergency frequency control schemes are schemes that help restore power system frequency in the event of extreme power system events, such as the simultaneous failure of multiple generators and/or transmission elements. The AEMC's *Emergency frequency control schemes* rule (which commenced on 6 April 2017) established a framework for the consideration and management of power system frequency risks arising from non-credible contingency events.[522] The rule places an obligation on AEMO to undertake, in collaboration with transmission network service providers, a *Power system frequency risk review* (PSFRR) at least every two years of risks associated with non-credible contingency events.[523]

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519 In the NEM, FCAS is sourced across eight markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised. FCAS market performance for 2017/18 is discussed in chapter 3.

520 Specifically, the rules now require new connecting generators to, at a minimum, have the capability to operate in frequency response mode, which is the ability to change active power output in response to a change in power system frequency.

521 The rules now require generators to be able to survive more onerous rate of change of frequency conditions.

522 For more information, see: https://www.aemc.gov.au/rule-changes/emergency-frequency-control-schemes-for-excess-gen

523 In June 2018, AEMO published the final report of the *PSFRR 2018*, which recommends material changes to emergency frequency control schemes for South Australia and Queensland. It also recommends the declaration of a protected event for South Australia designed to manage risks relating to a potential black system caused by transmission line failure and subsequent islanding during destructive wind conditions in South Australia. On 5 November 2018, AEMO submitted a request to the Panel seeking the declaration of a protected event in South Australia. On 13 December 2018, the Panel published a consultation paper seeking stakeholder feedback on the key issues in AEMO's request.

- ***The frequency operating standards:*** The frequency requirements that AEMO must meet are set out in the frequency operating standard, which is defined in the NER and determined by the Panel.[524] The purpose of the frequency operating standard is to define the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies. Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the frequency operating standard, while AEMO is responsible for maintaining the frequency within the ranges defined by the standard. The frequency operating standard currently consists of two separate standards - one for the mainland NEM and one for Tasmania - to reflect the different physical and market characteristics of the Tasmanian region as opposed to the mainland NEM.

  Figure 5.2 and Figure 5.3 set out the frequency bands defined in the frequency operating standard for the mainland NEM and Tasmania. The current requirement in the frequency operating standard for the mainland NEM and for Tasmanian is that, for 99 per cent of the time over any 30 day period, the power system is maintained within the range of 49.85 – 50.15Hz. During normal operation, in the absence of a contingency or load event, there is an allowance for brief excursions outside this band, but within the normal operating excursion band of 49.75 - 50.25 Hz. Under these conditions, if the power system frequency deviates outside the normal band, it must be returned to the normal band within five minutes.[525]

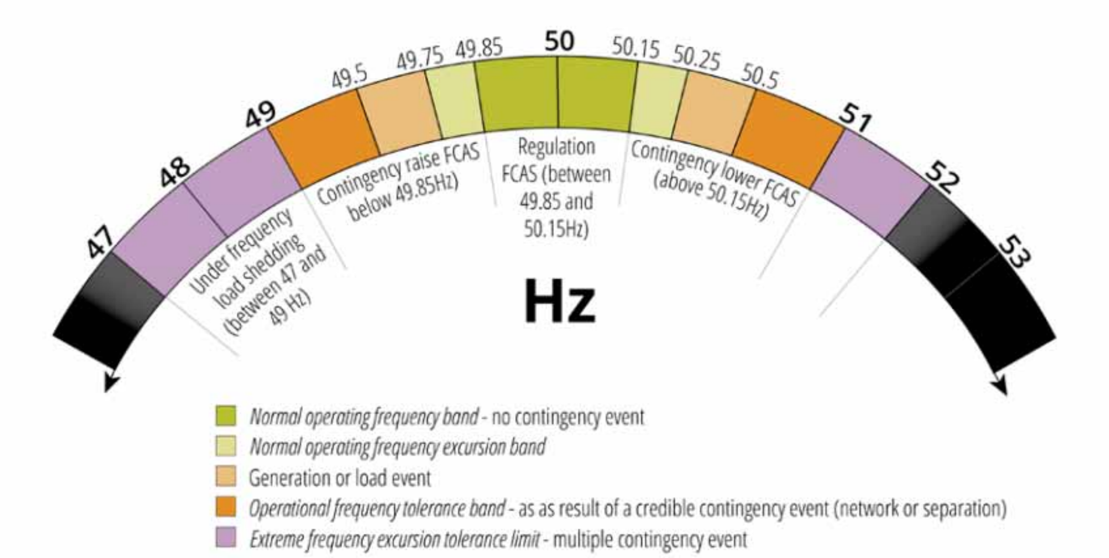
  In addition to the FOS, the NER also provide a broader requirement for AEMO, in any event (including frequency related), to take all reasonable actions to return the system to a secure operating state within 30 minutes.[526] These events, when the system was not returned to a secure operating state within 30 minutes, are discussed in section 5.1.1.

524 The frequency operating standards for the mainland and for Tasmania are available on the AEMC's website, at: http://www.aemc.gov.au/Australia-s-Energy-Market/Market-Legislation/Electricity-Guidelinesand-Standards. The Panel is currently in the second stage of its review of the frequency operating standard.

525 Reliability Panel, *Review of the frequency operating standard,* issues paper, July 2017.

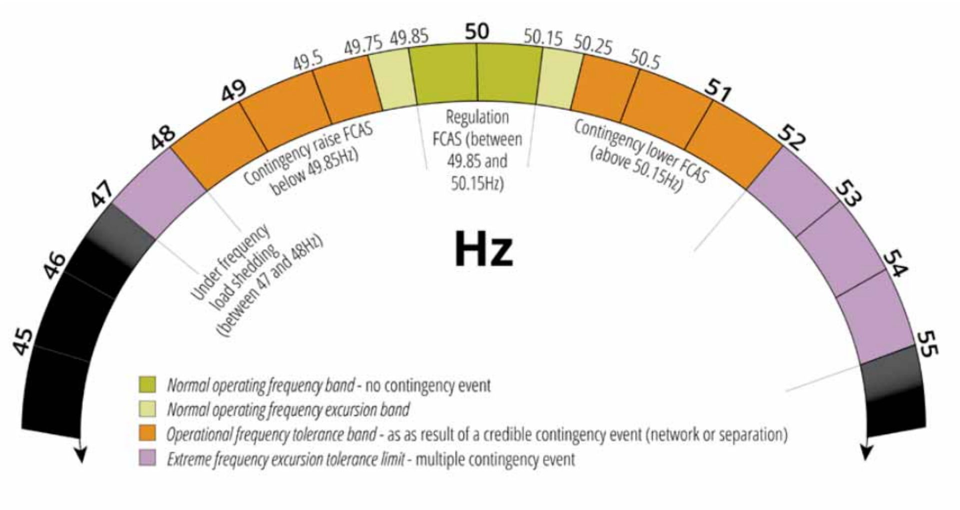
526 Clause 4.2.6(b)(1) of the NER.

Figure 5.2: Frequency bands - mainland NEM



Source: AEMC, *Frequency control frameworks review*, draft report, March 2018.

Figure 5.3: Frequency bands - Tasmania

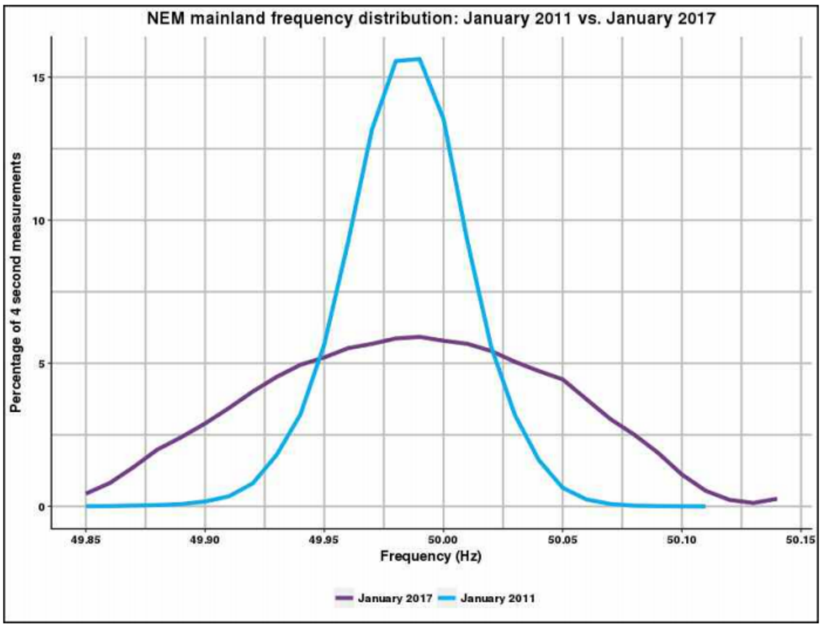


Source: AEMC, *Frequency control frameworks review*, draft report, March 2018.

Frequency performance

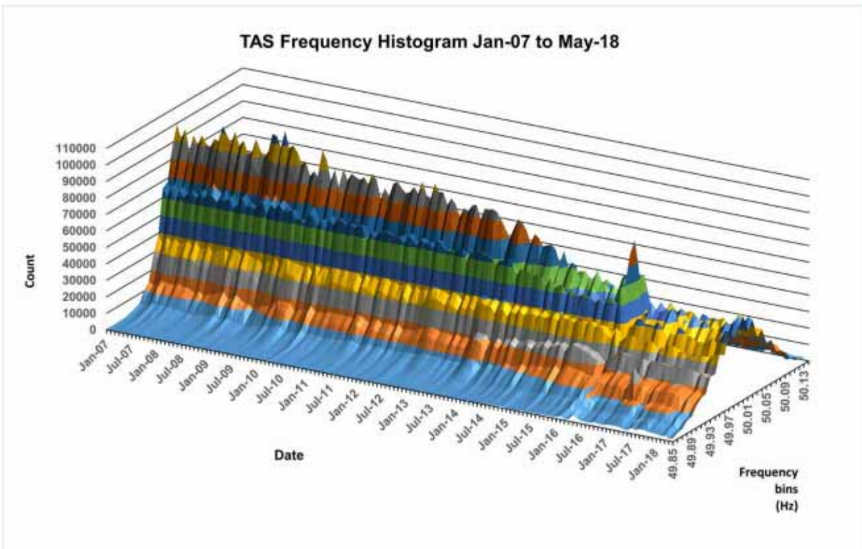
Frequency performance under normal operating conditions has been deteriorating in recent times. That is, there has been a flattening of the distribution of frequency within the normal band, as shown in Figure 5.4 for the NEM mainland and Figure 5.5 for Tasmania. As a result, the mainland and Tasmania power systems increasingly operate at frequencies further away from 50 Hz than has historically been the case.

Figure 5.4: Frequency distribution profile NEM mainland: Jan 2011 - Jan 2017



Source: AEMC, *Frequency Control Frameworks Review*, final report, July 2018.

Figure 5.5: Frequency distribution profile in Tasmania: Jan 2007 - May 2018



Source: AEMC, *Frequency Control Frameworks Review*, final report, July 2018.

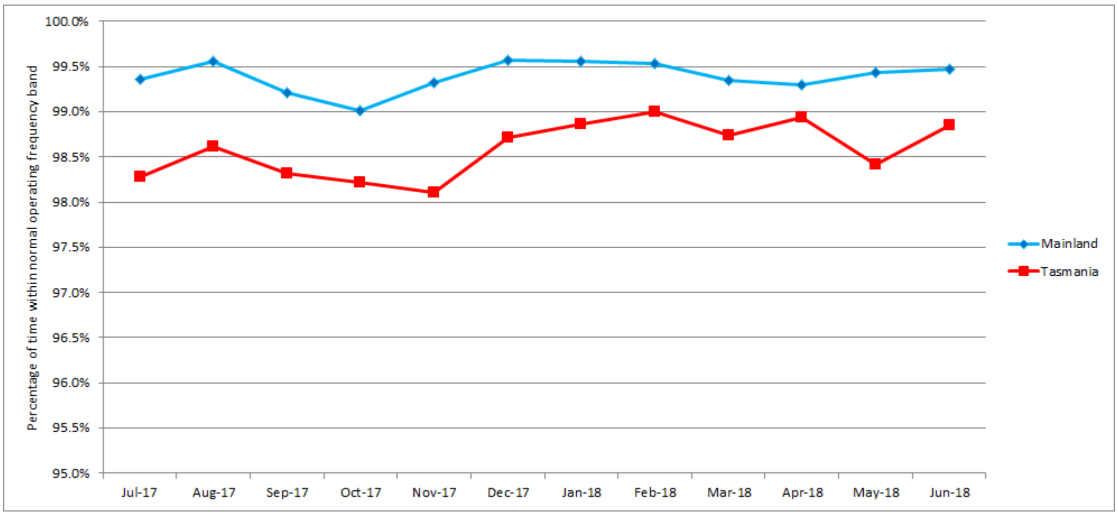
Mainland

On the mainland, frequency exceeded some of the requirements of the frequency operating standard and the mainland FOS was therefore not met in 2017/18. While the mainland frequency remained within the normal band more than 99 per cent of the time, there were events where system frequency took longer than five minutes to be returned to the normal band, and therefore that did not meet all the requirements of the frequency operating standard.

In 2017/18, the system operated outside the normal band for 192,380 seconds. This is an increase from 2016/17 (93,032 seconds) and from in 2015/16 (25,592 seconds). However, despite an increased amount of time operating outside the normal band, the percentage of time the mainland frequency was within the normal band met the required standard of 99 per cent over any 30-day period in 2017/18 (see Figure 5.6).[527]

However, in its *Frequency and time error monitoring* reports, AEMO has specified that there were 50 events that did not meet the frequency operating standard during 2017/18. This was due to the nature and duration of the relevant events, where the time outside the normal band was greater than five minutes, or where the frequency was outside the normal operating excursion band for a reason other than a contingency event or a load event.[528]

Figure 5.6: Percentage of time within normal band



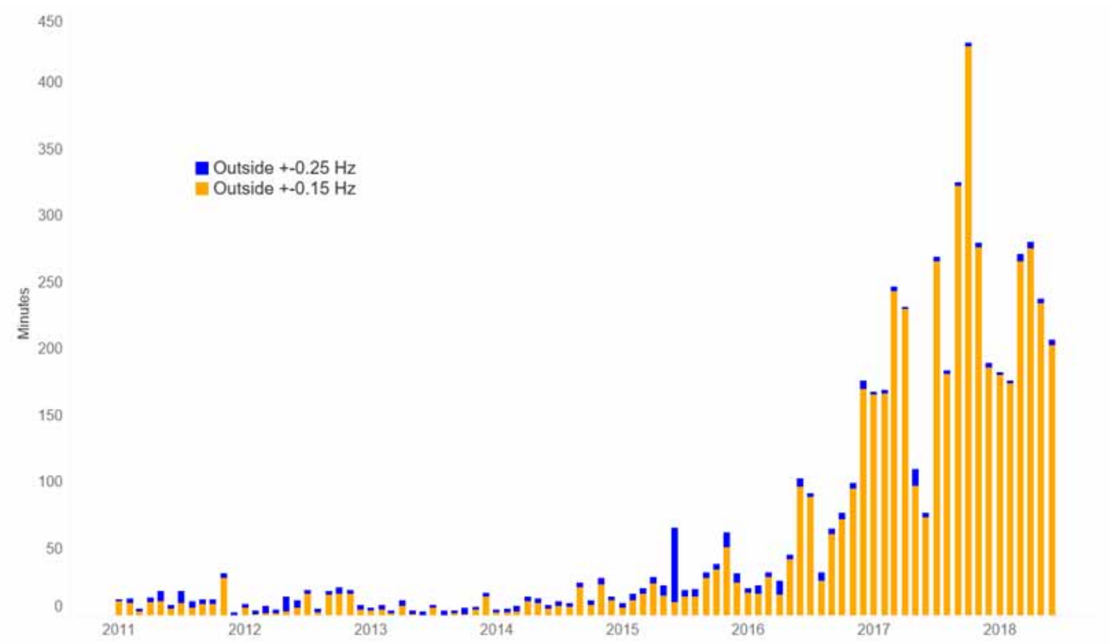
Source: AEMO.

Figure 5.7 shows historical frequency excursions on the mainland. The number of minutes the normal band has been exceeded on the mainland has increased over the last few years. This indicates that the frequency on the mainland has become increasingly variable, and is increasingly moving away from being contained within the normal band.

527 Reliability Panel, *The frequency operating standard*, November 2017, p. 1.

528 AEMO, *Frequency and time error monitoring reports*, March 2018, March 2018, June 2018 and July 2018.

Figure 5.7: NEM mainland frequency excursions over time



Source: AEMC analysis.

Tasmania

In Tasmania, frequency exceeded the requirements of the frequency operating standards. This means that the FOS was not met in 2017/18 in the Tasmanian region.

Tasmania was within the normal band for 98.57 per cent of the time, and therefore the FOS requirement was not met (see Figure 1.6). The standard provides that 99 per cent of the time frequency needs to be inside the normal band, in any 30 day period. The percentage of time the power system frequency was inside normal band did not meet this requirement for 11 months of the 2017/18 year (as compared with seven months in 2016/17). In 2017/18, Tasmania operated outside the normal band for 446,708 seconds. This is an increase from 2016/17 (338,992 seconds) and from 2015/16 (398,544 seconds).

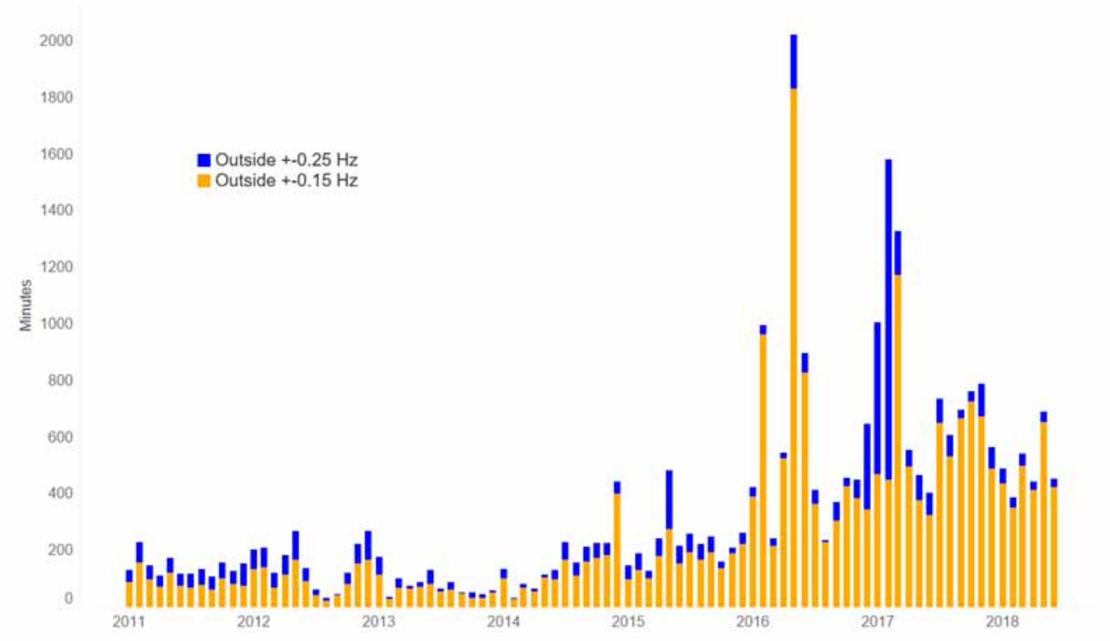
Further, there were 295 events that did not meet the frequency operating standard during 2017/18.[529] Hence, the frequency operating standard was not met in Tasmania, in regard to both requirements. This was due to the nature and duration of the relevant events, where the time outside the normal band was greater than five minutes, or where the frequency was outside the normal operating excursion band for a reason other than a contingency event or a load event.[530]

529 Ibid.

530 Ibid.

Figure 5.8 shows that over the past few years, the number of minutes where system frequency has been outside of the normal band has increased. The Panel notes that the number of frequency band exceedances in Tasmania is much greater than on the mainland. Additionally, in Tasmania system frequency has exceeded the more severe +/-0.25Hz band significantly more often than in the mainland.

Figure 5.8: Tasmania frequency excursions over time



Source: AEMC analysis.

More detail on the frequency operating standard is provided in appendix G.

Drivers of frequency control degradation

The Panel understands that there are various drivers of this degradation of frequency performance. As identified by AEMO and the AEMC in various reports, one of these causes is a reduction in generator frequency response during normal operation, due to generators making changes to their control systems that effectively decrease or remove their responsiveness to frequency deviations within the normal band.[531]

Analysis by AEMO and the AEMC has found that this change in generator response may be occurring as generators have widened their 'deadband' settings, which define the frequency threshold beyond which they will provide an automatic frequency response. This deadband widening has been enabled by generators upgrading their old mechanical governors with digital governors, which allows for the rapid changing of deadband settings. Furthermore,

531 AEMC, *Frequency control frameworks review*, draft report, March 2018, p. 42.

generators have been installing secondary control systems, which allow generating units to further reduce the extent of automatic primary frequency response.[532]

To explore the extent to which these changes to governor control are occurring, the Panel asked AEMO to provide data on how many generators are making these changes to generating systems. Accordingly, AEMO provided aggregated data on the types of generator plant alterations that have been performed in recent years.[533] This included information on when generators have made alterations to governor control systems.

The data analysis showed that around 43 per cent of all alterations made to generators between 2014 and 2018 were described as 'governor control system upgrade' or 'governor settings changes'.[534]

The Panel acknowledges that such changes do not automatically mean that all of the generators that have altered equipment in accordance with this clause have necessarily widened their deadbands or installed secondary control equipment to reduce frequency response. However, the Panel also notes that these are the kind of alterations that could enable the changes to governor settings identified by AEMO and the AEMC as being the key drivers of the worsening frequency performance of the NEM.

AEMO has provided further analysis of the extent to which primary frequency control capability has reduced in the NEM. Over 2017, AEMO conducted a survey of generators to explore frequency responsiveness of the NEM generating fleet.

For the survey purposes, AEMO categorised settings as follows:

- Continuous frequency support with +/-50 mhz deadband - that is, a continuous response from generators when the frequency was within the range of 49.95Hz - 50.05Hz. [535]
- Continuous frequency support with +/-100 mhz deadband - that is, a continuous response from generators when the frequency was within the range of 49.90Hz - 50.10Hz.
- Wider deadbands, no frequency response, or unknown response characteristics.

The survey results are as follows:

532 Ibid.

533 In accordance with clauses 5.3.9 and 5.3.10 of the NER, a market participant must not commission altered generating plant until the relevant network service provider has advised the generator that it and AEMO are satisfied that it meets the relevant technical requirements.

534 In total, 14 of these alterations were made over the time period.

535 These deadbands represent the frequency responsiveness of the generator. This means that the generator will only change its active power output in response to power system frequency, when power system frequency is outside the limits of the generator's deadband. The current requirement in the FOS is that, for 99 per cent of the time over any 30-day period, the power system is maintained within the range of 49.85 - 50.15Hz which is a normal operating frequency band.

Table 5.2: Generator survey summary

STATE	<=50 MHZ (TOTAL MW REGISTERED CAPACITY)	<=100 MHZ (TOTAL MW REGISTERED CAPACITY)	WIDER OR UNKNOWN (TOTAL MW REGISTERED CAPACITY)
NEM total	9,514	3,632	40,671
Queensland	304	2,575	11,706
New South Wales	5,000	0	13,552
Victoria	3,202	0	8,449
South Australia	713	0	5,115
Tasmania	295	1,057	1,849

Source: AEMO.
Note: Totals may differ slightly to figures elsewhere due to filtering and rounding.

This analysis shows that around 13,000 MW of the generation capacity surveyed had deadbands set within the normal operating frequency band, with approximately 40,671 MW of capacity had deadbands set outside of the normal band and would not therefore be considered frequency-responsive within the normal range. A wider deadband means that these generators will not provide an automatic response to a frequency disturbance until frequency has moved a significant distance away from the nominal 50Hz, or at least until the frequency has moved outside of whatever deadband settings the generator has implemented.

The AEMC's final report for the *Frequency control frameworks review* concluded that there is a need to find a permanent solution to the deterioration of frequency control. The report provided a detailed explanation of one possible policy mechanism, referred to as a deviation pricing mechanism, which could be further developed to efficiently value the provision of frequency services under normal operation in the longer term. The AEMC also flagged the possibility of the introduction of an interim measures to manage frequency performance during normal operation, where AEMO considered this necessary.[536]

The *Frequency control frameworks review* report also set out a spectrum of potential frameworks for the procurement and dispatch of FCAS to address the potential deficiencies of the existing arrangements as the system security needs of the system changes.[537]

During the *Frequency control frameworks review,* AEMO notified the AEMC that it is undertaking a range of actions in an attempt to better understand the drivers of the deterioration of frequency performance under normal operating conditions, and to reverse this deterioration, or at the very least halt any further deterioration. Specifically, AEMO stated that it is or has:[538]

536 AEMO, *Frequency control frameworks review*, final report, July 2018, p. 38.

537 Ibid.

538 Ibid.

- conducted a survey of generator frequency control settings (completed April 2018)
- conducted a trial of primary frequency control in Tasmania (completed May 2018)
- published a revised causer pays procedure to remove aspects of it that may be discouraging the provision of a primary regulating response (completed November 2018)
- conducting automatic generation control system (AGC) tuning
- investigating the need to increase the quantity of regulating FCAS on a static or dynamic basis, and doing so if necessary
- conducting a trial of primary frequency control in the mainland, building on experience from the Tasmanian trial undertaken in May 2018
- monitoring and reporting quarterly on frequency outcomes, on a voluntary basis[539]
- continued coordination of proposed changes to generator governor settings following the results of the survey conducted in April 2018.

Most recently, AEMO published the final report into the Queensland and South Australia system separation event that occurred on 25 August 2018. The analysis in the report highlights a decline in frequency control capability and system resilience to events larger than single credible contingencies in the NEM. AEMO considers this an immediate risk to the power system. AEMO made a number of recommendations to improve frequency performance. The principal recommendation is the implementation of interim actions to deliver sufficient primary frequency control in the NEM.[540] This incident and AEMO's recommendations are discussed in more detail in section 5.2.

As noted above, the AEMC established a work program at the conclusion of the *Frequency control frameworks review*, which included the possibility of an interim measure for frequency control. The AEMC intends to work closely with AEMO over the coming months to consider the range of options available to address the frequency degradation in the NEM. As it was outlined in AEMO's *Queensland and South Australia system separation - 25 August 2018* incident report, appropriate interim arrangements to increase primary frequency control responses will be established, including through rule changes submitted to the AEMC as required.[541]

5.1.3 Emergency frequency control schemes

If a frequency deviation results in the frequency moving significantly outside of the normal ranges, automatic protection systems operate to trip load (under-frequency load shedding (UFLS) schemes) or generation (over-frequency generation shedding (OFGS) schemes) to bring the frequency back to within the normal operating standards.[542]

539 AEMO has already published *Frequency and time error monitoring reports* for the 1st and 2nd Quarters of 2018.

540 AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018,* January 2019, p. 7.

541 Ibid, p. 8.

542 Typically, automatic UFLS schemes are triggered when the frequency moves outside of the operational frequency tolerance band of 49Hz to 51Hz. While UFLS schemes are universal in the NEM, OFGS schemes are more rare.

Additional schemes are in place to reduce effective contingency sizes, or to respond to specific contingency events to prevent system separation and uncontrolled frequency disturbances in the resulting islanded sub-networks.

In June 2018, AEMO published the final report of its inaugural *2018 Power system frequency risk review* (PSFRR), which recommends material changes to emergency frequency control schemes for South Australia and Queensland.[543] It also recommends the declaration of a protected event for South Australia designed to manage risks relating to a potential black system caused by transmission line failure and subsequent islanding during destructive wind conditions in South Australia. On 5 November 2018, AEMO submitted a request to the Panel seeking the declaration of a protected event in South Australia. On 13 December 2018, the Panel published a consultation paper seeking stakeholder feedback on the key issues in AEMO's request.

Table 5.3 summarises the existing emergency frequency control schemes across the NEM regions, which were reviewed by AEMO in its *2018 PSFRR.* This table includes AEMO's initial assessment as to whether the relevant scheme requires alteration or amendment.

Table 5.3: Existing emergency frequency control schemes

REGION	EXISTING EMERGENCY FREQUENCY CONTROL SCHEMES	AEMO'S ASSESSMENT
New South Wales	The New South Wales UFLS scheme	No need was identified to modify the scheme in 2018. However, emerging issues, such as possible residential rooftop PV impact on UFLS, warrant a review in 2019.
Queensland	Queensland UFLS scheme	No need was identified to modify the scheme in 2018. However, emerging issues, such as possible residential rooftop PV impact on UFLS, warrant a review in 2019.
	Central Queensland to Southern Queensland Special Protection Scheme (CQ–SQ SPS)	AEMO recommends amending the existing CQ–SQ SPS, to be effective for higher southerly flows that are anticipated as generation projects connect in North Queensland. AEMO estimates that the modification can be completed within two years.
	Stanwell–Broadsound System	No need was identified to modify the

543 In March 2017, the AEMC published a final rule for the *Emergency frequency control schemes* rule change request. The final rule placed a clear obligation on AEMO to undertake, in collaboration with TNSPs, an integrated, periodic review of power system frequency risks associated with non-credible contingency events – the *Power system frequency risk review* – as part of a governance framework for emergency frequency control. For more information see: https://www.aemc.gov.au/rule-changes/emergency-frequency-control-schemes-for-excess-gen.

REGION	EXISTING EMERGENCY FREQUENCY CONTROL SCHEMES	AEMO'S ASSESSMENT
South Australia	UFLS scheme	No need was identified to modify the scheme in 2018. However, emerging issues, such as possible residential rooftop PV impact on UFLS, warrant a review in 2019.
	OFGS scheme	No need was identified to modify the scheme in 2018.
	SIPS	AEMO recommends implementing an upgrade to the SIPS to reduce the likelihood that a loss of multiple generators in South Australia will lead to separation and a black system. AEMO estimates that the modification can be completed within two years, and recommends that it be progressed as a protected event emergency frequency control scheme.[1]
Tasmania	Frequency Control System Protection Scheme	No need was identified to modify the scheme in 2018.
	OFGS scheme	No need was identified to modify the scheme in 2018.
	Tamar Valley Generator Contingency Scheme	No need was identified to modify the scheme in 2018.
	UFLS scheme	No need was identified to modify the scheme in 2018.
Victoria	Victoria UFLS scheme	No need was identified to modify the scheme in 2018.
	Emergency Alcoa Portland Tripping scheme	In *2018 PSFRR,* AEMO has not identified an immediate need to modify the scheme. However, after a major system security event on 25 August 2018, when Queensland and South Australia system separation occurred, AEMO recommended to immediately commence a review of this scheme to identify improvements.
	Interconnector Emergency	AEMO has not identified any need to

REGION	EXISTING EMERGENCY FREQUENCY CONTROL SCHEMES	AEMO'S ASSESSMENT
	Control Scheme	modify the scheme beyond the planned upgrade.[2]

Source: AEMO, *Power system frequency risk review*, final report, June 2018.

Note: 1 - On 5 November 2018, AEMO submitted a request to the Panel seeking the declaration of a protected event to help AEMO maintain power system security in South Australia. On 13 December 2018, the Panel published a consultation paper seeking stakeholder feedback on the key issues in AEMO's request. For more information, see: https://www.aemc.gov.au/market-reviews-advice/request-declaration-protected-event-november-2018

Note: 2 - AEMO, in its role as Victorian TNSP, is planning to implement tripping of hydroelectric generating units in the Victorian region upon trip of both South Morang – Dederang 330 kV lines in 2019.

In its *Queensland and South Australia system separation - 25 August 2018* incident report, AEMO made a number of recommendations to reduce the risk of islanding regions from the NEM by reviewing and improving protection schemes and other control and protection schemes. Specifically, it was recommended:[544]

- AEMO to immediately commence a review of the Emergency Alcoa Portland Tripping scheme to identify improvements by 1 July 2019.
- AEMO to review other existing AC interconnector schemes with TNSPs, to determine whether their performance remains fit for purpose in the changing environment and are properly co-ordinated, by Q1 2020.
- AEMO to continue implementation and investigate any further functional requirements of emergency frequency control schemes for each region, commencing with South Australia and Queensland prior Q1 2020.

The Panel notes that in 2017/18 there were no occasions where under frequency load shedding or over-frequency generation shedding schemes were triggered.[545] For comparison, in 2016/17 there were three occasions where under frequency load shedding schemes were triggered.

Impact of rooftop solar PV on the operation of emergency frequency control schemes

AEMO notes that the high penetration of rooftop solar PV presents some challenges to the operation of emergency frequency control schemes.

As rooftop PV units are installed in distribution networks, TNSPs and AEMO have a limited visibility of the actual state of load feeders in these networks. Emergency frequency control schemes such as UFLS and OFGS rely on visibilities of loads and generation, as that is how these schemes have been designed. Rooftop PV may blur this visibility substantially.

If UFLS has been activated, not only load but the distributed generation may also be disconnected. That may lead to further decrease in frequency and as a result the disconnected loads may be considerably higher than intended and under the worst case scenario system collapse may occur.

544 AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018,* January 2019, p. 8.

545 The separation event on 25 August 2018 is outside the review period for this AMPR.

One of the solutions to this issue would be to install 'directional' relays (dynamic arming) that would measure and determine whether the measured load is negative i.e. there is more PV generation than load on a particular feeder. As a result, and depending on other variables, the UFLS scheme may or may not trip this particular feeder.

It is also worthwhile mentioning that traditionally AEMO interpreted the NER requirements for load shedding capability to mean that '*60% of the total load of a region should be connected to under frequency protection*'(as expressed in AEMO's *Power System Security Guidelines*). At times when operational demand is zero, this could suggest that no load shedding capability is required. This may not reflect actual power system needs or strike an appropriate balance of cost and risk for consumers. Different approaches to assessing the adequacy of load shedding schemes may be required.

In summary, distributed PV will impact on the operation of emergency frequency control schemes in a variety of ways:

- **UFLS** – Rooftop solar PV is co-located with customer loads in the distribution network. As PV penetration levels grow, this may reduce the "net load" available for shedding at a feeder level, and therefore may progressively reduce the efficacy of the UFLS. When a feeder is in reverse flows (feeding energy back into the grid), tripping that feeder will exacerbate an under-frequency disturbance, rather than helping to correct it.
- **OFGS** – At times of high distributed PV generation, there may be very little centralised generation operating. This means that there is very little centralised generation available to shed in a coordinated way, reducing the ability of the scheme to arrest an over-frequency event.
- **SPS** (Special Protection Scheme) - Will be affected similarly to UFLS and OFGS, depending on whether they disconnect loads or generation.

AEMO has started a review of NEM UFLS schemes starting with South Australia being the most urgent. AEMO is also developing proposals to mitigate the impact of UFLS cascading failure.

5.1.4 New frequency response technologies

The Panel notes that the market is adapting to the technology transformation that is currently occurring in the NEM, and that there are a number of examples of new technologies and approaches being integrated and trialled in the NEM to provide new ways to control power system frequency.

There are a range of new technologies connecting to the system, including battery storage, that are capable of providing FCAS. These technologies offer the potential to provide frequency response services that act much faster than the existing services, perhaps as quickly as a few hundred milliseconds. Such fast frequency response (FFR) services could act to arrest the frequency change more quickly than the fastest existing contingency services, which have response times of up to six seconds.[546]

546 AEMC, *Frequency control frameworks review*, final report, July 2018, p. 27.

AEMO states that it is looking at facilitated proof of concept projects in order to build confidence in the capability of FFR to deliver the frequency control services required in the NEM.[547] AEMO is pursuing collaborative opportunities with ARENA and market participants to develop trials of new services, including FFR.[548]

There are a number of examples of new technologies and approaches being integrated and trialled in the NEM. These various developments are described in further detail below.

EnerNOC

EnerNOC's aggregated contingency raise resource has been participating in the six-second, sixty-second and five-minute FCAS raise markets since October 2017. EnerNOC has indicated that its FCAS resource is comprised of distributed, aggregated switching controllers installed at commercial and industrial energy users' facilities throughout the NEM. The MW quantities that EnerNOC bids into the market vary by trading interval, in line with customers' production schedules and real-time demand.[549]

Hornsdale Power Reserve

The Hornsdale Power Reserve (HPR) is located near Jamestown, north of Adelaide in South Australia. The HPR battery is rated at 100 MW discharge and 80 MW charge, and has a storage capacity of 129 MWh.

The HPR provides a range of services under commercial agreements between the South Australian Government, Tesla (the battery technology provider), and NEOEN (the owner and operator of the Hornsdale Wind Farm). The HPR is capable of offering the following:[550]

- **Energy arbitrage**. Under normal conditions, 30 MW of the battery's discharge capacity is made available to NEOEN for commercial operation in the NEM.
- **Reserve energy capacity.** The remaining 70 MW of battery discharge capacity is reserved for power system reliability purposes.[551]
- **Network loading control ancillary services.** The HPR was included in the SA System Integrity Protection Scheme (SIPS) – which is intended to reduce the likelihood of the South Australia power system separating from the rest of the NEM following a sudden increase in flow on the Heywood Interconnector. The SIPS control scheme is intended to detect high flows on the Heywood Interconnector and trigger the HPR to start discharging at 100 MW as quickly as possible.
- **FCAS.** The HPR is registered to provide all eight FCAS services, and actively participates in all eight FCAS markets.

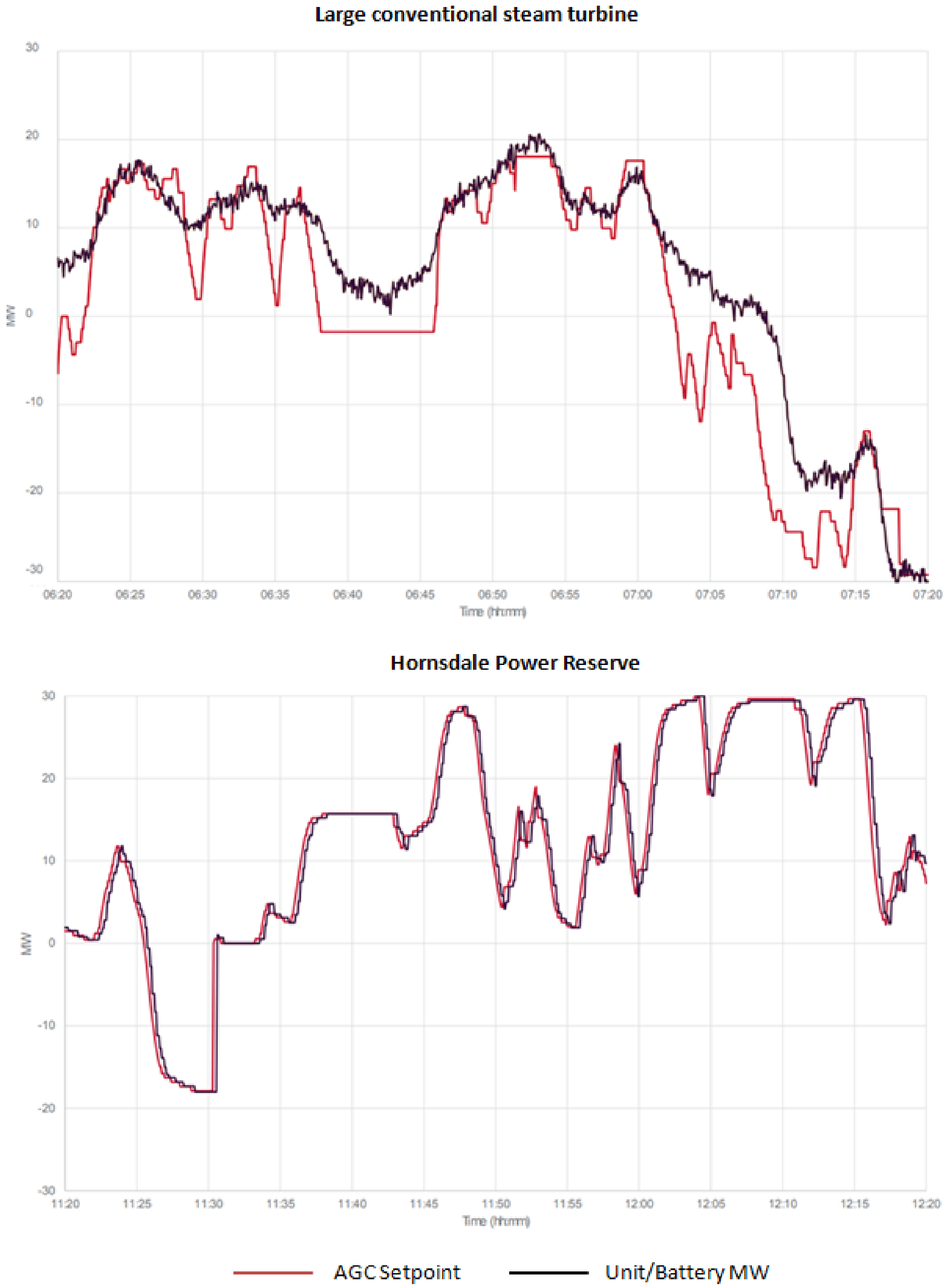
547 AEMO, *Power system requirements,* reference paper, March 2018, p. 15.
548 AEMC, *Frequency control frameworks review*, final report, July 2018, p. 82.
549 EnerNOC, *Submission on the Reliability frameworks review,* interim report, February 2018, p. 15.
550 AEMO, *Initial operation of the Hornsdale Power Reserve Battery Energy Storage System*, April 2018, p. 4.
551 As at the end of 2017/18, this 70 MW reserve capacity has never been dispatched. Under arrangements with the South Australian government, this capacity is offered into the NEM at the Market Price Cap, ensuring this component of the HPR will not be dispatched ahead of other generation in South Australia.

AEMO has noted that the regulation FCAS provided by the HPR is both rapid and precise, compared to the service typically provided by a conventional synchronous generation unit.[552] Figure 5.9 compares the accuracy and response speed of a large conventional steam turbine and the HPR to the AGC set-point control targets for frequency regulation over a one-hour period. It provides a clear illustration of the high level of accuracy of the service provision from the new battery technology.[553]

552 AEMO, *Initial operation of the Hornsdale Power Reserve Battery Energy Storage System*, April 2018, p. 5.

553 While experience shows that the HPR is capable of providing very high quality regulation FCAS, regulation FCAS arrangements in the NEM do not currently recognise differences in the 'quality' of service delivery. The Market Ancillary Services Specification (MASS), which specifies each market ancillary service, and how it is to be quantified, does not address performance requirements for regulation FCAS. All regulation FCAS is essentially considered to be equal and interchangeable, and providers are paid the same price per MW of enabled service, regardless of performance.

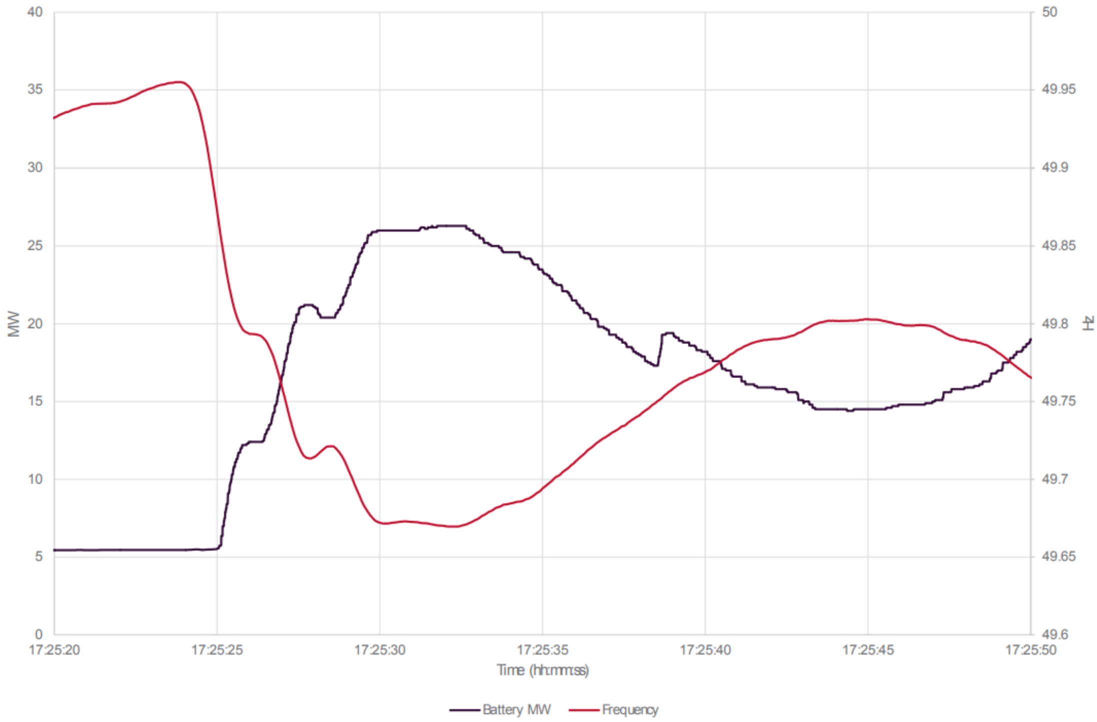
Figure 5.9: Regulation FCAS response



Source: AEMO, *Initial operation of the Hornsdale Power Reserve Battery Energy Storage System*, April 2018.

Commissioning tests and simulations confirm that the HPR is also capable of responding rapidly and accurately to a contingency event. An example of the HPR's actual response to the trip of 689 MW of generation in New South Wales on 18 December 2017 is shown in Figure 5.10 below.[554]

Figure 5.10: The HPR response to trip of generation in New South Wales, 18 December 2017



Source: AEMO, *Initial operation of the Hornsdale Power Reserve Battery Energy Storage System*, April 2018.

Further, in its *Queensland and South Australia system separation - 25 August 2018* incident report, AEMO stated that the HPR response during the major contingency event was consistent with its design. It contributed to both arresting the initial decline in system frequency, and then by rapidly changing output from generation back to load, to arrest the over-frequency condition in South Australia following separation from Victoria. According to AEMO, the very rapid speed of delivery of frequency response from the HPR was valuable in this event, and ensured the response contributed to limiting the under- and over-frequency conditions.[555]

554 Similar to regulation FCAS, due to the way the MASS assesses contingency FCAS capability, HPR's high response capability is not recognised or rewarded differently to the service provided by conventional synchronous generation.

555 AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018,* January 2019, p. 67.

ESCRI-SA Battery Energy Storage Project (BESS)

BESS is a grid connected 30 MW / 8 MWh[556] lithium ion storage system located seven kilometres south-east of Stansbury and adjacent to ElectraNet's existing Dalrymple substation.[557]

The BESS is owned and maintained by ElectraNet, with the operation of the BESS leased to AGL Energy for twelve years. AGL operates it to provide competitive market services, while ElectraNet provides regulated services.[558] ARENA provided $12 million in funding toward the project.[559]

The battery system has been designed to deliver four main services:[560]

- Regulated services provided by ElectraNet:
  - **Islanded operation.** The BESS was designed to provide islanded grid forming services for the Dalrymple local service area by providing the necessary power system frequency reference and control, and the reactive power necessary to maintain a stable power system voltage. The power system island includes all loads and rooftop solar PV installations downstream of Dalrymple substation and a portion of Wattle Point Wind Farm. This is expected to reduce unserved energy to Dalrymple following loss of supply.
  - **Fast frequency response.** The battery is expected to reduce constraints on the Heywood Interconnector, resulting in increased flows on the interconnector.
- Competitive services provided by AGL:
  - **Contingency FCAS.** The BESS was registered to provide contingency FCAS services.
  - **Energy trading.** Market trading of electricity in the NEM through the provision of market caps.

The Dalrymple battery energy storage system commenced commercial operations in December 2018.

Hornsdale Wind Farm trial

The Hornsdale Wind Farm trial was announced in August 2017 and was a joint ARENA/NEOEN project aimed at establishing the feasibility of wind farms providing both regulation and contingency raise and lower services. It involved testing the technical capability of Type 4 wind turbines to be remotely controlled by AEMO, followed by a 48-hour market trial to test the ability of the wind farm to fully participate in NEM energy and FCAS markets, under a variety of wind and market conditions.[561]

556 The maximum design charge / discharge rate of the BESS is 30 MW and the design capacity of the BESS is 8 MWh at the end of the 12-year design life. The initial installed capacity of the battery is higher to allow for battery deterioration over the BESS design life.

557 This area of the Yorke Peninsula is supplied by one distribution line that is susceptible to frequent disruptions.

558 ElectraNet, *About the battery,* accessed on 26 November 2018, at: https://www.escri-sa.com.au/about/

559 ARENA, *30 million dollar 30 MW SA battery*, media release, accessed on 26 November 2018, at: https://arena.gov.au/news/30-million-dollar-30mw-sa-battery/

560 ElectraNet, *ESCRI-SA project summary report - the journey to financial close*, May 2018.

561 AEMC, *Frequency control frameworks review*, draft report, March 2018, p. 151.

The trial run from 19 December 2017 to 1 February 2018. The wind farm delivered across six of the eight different FCAS markets and met the project's objectives.[562] Without any major outages during the trail, the potential for the wind farm to deliver fast FCAS (six-second response) following a contingency event could not be evaluated. This will be further explored through ARENA's frequency control trial at Musselroe Wind Farm in Tasmania.[563]

As a result of the successful trial, the Hornsdale Wind Farm is now registered and offering FCAS services in the NEM.[564] This is the first time a wind farm has been registered to offer and deliver FCAS services in Australia.

ActewAGL's Virtual Power Plant

In late 2018, ActewAGL, acting as a Financially Responsible Market Participant[565], registered with AEMO its one MW Virtual Power Plant[566] to provide six-second, sixty-second and five-minute FCAS lower services. The VPP is operated using the Reposit Power technology. This is the first time a VPP has been registered to offer and deliver FCAS services in Australia.

The AEMC is collaborating with AEMO, the AER and members of the Distributed Energy Integration Program, to establish the VPP demonstrations. These demonstrations are the first step in a broad program of work designed to inform changes to regulatory frameworks and operational processes so distributed energy resources can be effectively integrated into the NEM, maximising value to consumers while also supporting power system security.[567]

Musselroe Wind Farm trial

The Musselroe Wind Farm trial was announced in March 2018 and is a joint ARENA/Woolnorth project aimed at extending the work undertaken at Hornsdale. The trial intends to investigate the technical feasibility of providing FCAS and the economic and commercial viability of the wind farm to provide ancillary services and participate in FCAS markets. This study will also examine options to store surplus wind energy when constraints on the network prevent energy from being used.[568]

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562 The Panel understands that the Hornsdale Wind Farm was unable to offer six-second fast raise or lower services, due to interactions with fault ride through and reactive power injection obligations.

563 AEMO, *Hornsdale Wind Farm 2 FCAS trial*, July 2018, p. 5.

564 Hornsdale Wind Farm cannot provide six-second contingency service because of its response when there is a voltage disturbance along with a frequency disturbance, i.e. the output dropped for the first few seconds. Hornsdale Wind Farm 1 and 3 deliver only regulation services. Hornsdale Wind Farm 2 delivers six services. The ability of other wind farm projects to provide fast FCAS will be further investigated in the Musselroe Wind Farm FCAS Trial.

565 Financially Responsible Market Participant is a market participant which has either classified the connection point as one of its market loads; classified the generating unit connected at that connection point as a market generating unit; or classified the network services at that connection point as a market network service. Chapter 10 of the NER.

566 A VPP broadly refers to an aggregation of resources, coordinated using software and communications technology to deliver services that have traditionally been performed by a conventional generator.

567 For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Virtual-Power-Plant-Demonstrations

568 AEMC, *Frequency control frameworks review*, draft report, March 2018, p. 151.

5.1.5 Voltage limits

Satisfactory voltage limits represent the minimum or maximum safe operating level of a network asset set by the asset owner[569] and which should not normally be exceeded. A secure voltage limit is the normal minimum or maximum operating limit of a network asset such that, post contingency, voltage levels will not exceed the satisfactory limits.

An emerging challenge in the NEM relates to circumstances where a lack of online synchronous generation, often combined with low levels of demand, can create significant overvoltages on parts of the transmission system.

This is an emerging issue in Victoria and South Australia, but may become more prevalent in other regions following changes in demand patterns and the generation fleet.

This section describes this emerging issue, and summarises some of the regulatory solutions currently being progressed.

Overvoltages as an emerging system security issue

System voltages are controlled through the injection and absorption of reactive power. Lightly loaded transmission lines inject reactive power into the power system.[570] The extent to which reactive power is injected by a transmission line is based on its operating voltage (its kV rating), its length, and the amount of loading on the line. An injection of excess reactive power can create unacceptable over-voltages.[571]

A number of developments in the power system are resulting in excess injection of reactive power and subsequently driving new issues related to overvoltages. This includes the retirement of synchronous generation, which has the capability to absorb reactive power, and therefore relieve over voltages on these high kV lines. Changing demand patterns, particularly decreases in levels of minimum demand, further exacerbate system overvoltages by reducing line loading on high kV lines.

Operation of the power system is becoming more difficult to manage due to increased variability of demand, for example as high levels of rooftop PV result in minimum demand periods in the middle of the day. Currently residential rooftop PV does not inject reactive power in the system, and may also reduces the need for reactive power as there is no voltage drop across the system. The reduction in demand at the end of the network (customers) and the lines running below its surge impedance loading level (and therefore generating reactive power in excess) cause overvoltages. Without prudent investment in reactive compensation, intervention – such as having to direct fast start synchronous generation online to provide reactive support – may become a more frequent occurrence.

569 While satisfactory voltage limits are set by the asset owner, they must also comply with the relevant Australian Standards and requirements of the NER.

570 In an alternating current power system, reactive power is used to maintain voltages within defined limits. Reactive power can be 'injected' or 'absorbed' by synchronous machines like synchronous generators and synchronous condensers, or various types of reactive plant. The injection or absorption of reactive power is used to raise or lower system voltages, respectively.

571 Overvoltages can cause damage to electrical equipment, including network assets, generators and end user equipment, by overloading insulation protection and causing short circuit related problems.

AEMO has identified that the retirement of large synchronous generators in certain states has created a need for additional reactive support to maintain transmission system voltages within operational limits during minimum demand periods.[572] The lack of reactive power absorption capability could be especially evident overnight, when load is low and synchronous generators turn off due to low, or even negative, wholesale prices.

Over-voltages cannot be solved by load shedding. To address these issues, AEMO currently uses the following instruments:

- issuing directions to a generator to return or remain in service to assist with voltage control, through the provision of reactive support
- de-energisation of high voltage transmission lines.

De-energisation of high voltage transmission lines is used as a short term operational measure, to manage high transmission system voltages. This would typically be when all standard practices, such as utilising the reactive power capabilities of generators and transformer tapping, are exhausted.[573] This solution has been used in Victoria in recent years.

While line de-energisation can provide a temporary solution to overvoltages, it can also reduce the overall reliability and stability of the system, by reducing the number of flow paths available for the transmission of power. Repeated line switching can also reduce the life of switching equipment.

Victoria

In Victoria, high voltages on the 220 kV and 500 kV network in the South-West Corridor around Geelong, Keilor, Portland, and Moorabool have been observed during minimum demand periods. Further, the closure of Hazelwood Power Station in March 2017 has exacerbated the issue by removing a generator that had the capability to absorb reactive power and help regulate system voltages.[574] Briefly, voltage control issues in Victoria have included the following developments:

- Before March 2017, AEMO managed excessively high voltages with short term de-energisation of a single 500 kV line, when other means of voltage control had been exhausted.
- Following the closure of Hazelwood in March 2017, the frequency of low 500 kV line loading under minimum demand and subsequent over voltages have increased. AEMO and the relevant DNSPs then commenced switching off distribution capacitors during light load periods to manage high voltages.[575] About 270 MVAr of distribution capacitors have been switched off until at least the end of summer 2017/18.

572 AEMO*, Victorian reactive power support: project specification consultation report,* May 2018, p. 3. In Victoria, the planning and ownership of the Victorian transmission network is split between AEMO and transmission network service providers. AEMO is responsible for planning and directing augmentations to the network, and plans and procures services from third parties to achieve this.

573 AEMO, *Victorian reactive power support: project specification consultation report*, May 2018, p. 7.

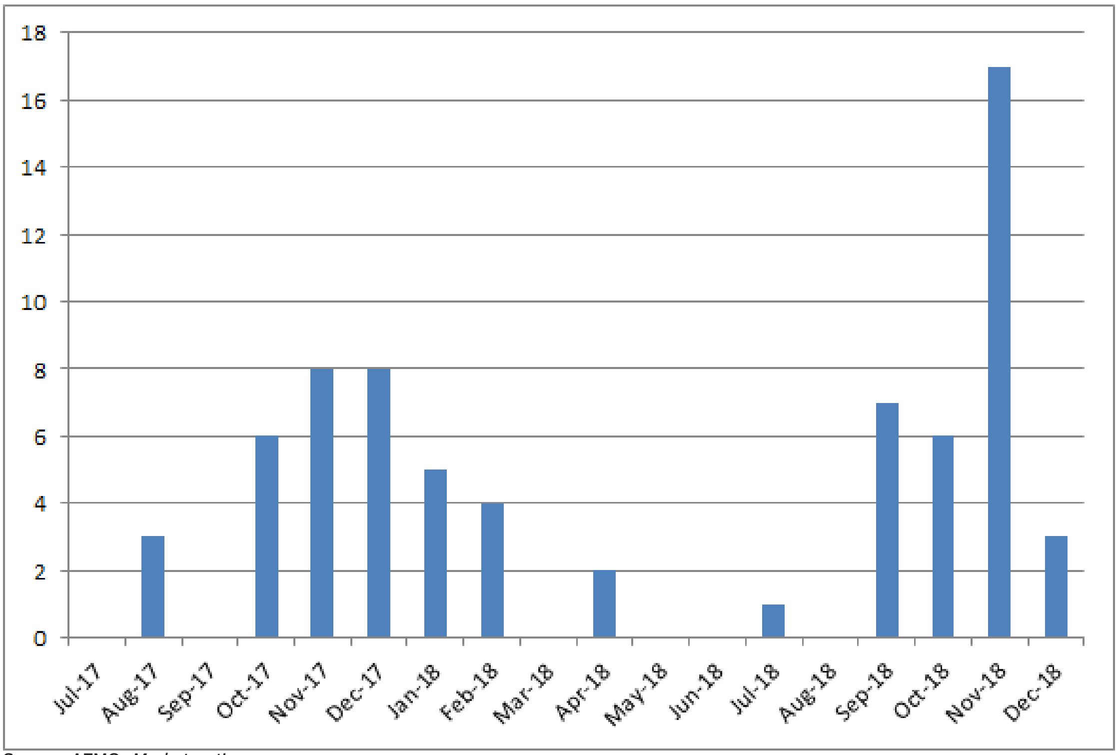
574 Ibid, p. 3.

575 This measure can compensate the loss of reactive power support from Hazelwood, by reducing the amount of reactive power injection to the transmission network from distribution networks.

- However, even with switching of distribution capacitors, the need for de-energisation of 500 kV lines has increased. AEMO stated that between March 2017 and May 2018 the de-energisation of 500 kV lines was implemented more than 40 times during light load periods to manage high voltage, and de-energisation of two 500 kV lines was required five times during very light load periods.[576] Figure 5.11 shows the number of times de-energisation of lines was implemented in Victoria between May 2016 and December 2018. The figure demonstrates that the number of times 500 kV transmission lines were de-energised increased significantly in November 2018.

  The Panel also notes that line de-energisation usually occurs during night-time, when demand is low.

Figure 5.11: Number of times 500 kV transmission lines were de-energised to manage voltage in Victoria



Source: AEMO, *Market notices*.

In November 2018, a particularly significant voltage control incident occurred in Victoria. This incident, which required the de-energisation of three 500 kV lines for the first time in the NEM, provides an illustration of these emerging voltage control issues. This event is described in more detail in Box 4.[577] In response to this event, in December 2018 AEMO

576 AEMO, *Victorian reactive power support: project specification consultation report,* May 2018, p. 7.

577 As this event falls outside the 2018 AMPR review period, the Panel will discuss it in greater detail in the 2019 AMPR.

declared an NSCAS gap for voltage control in Victoria. AEMO, in its Victorian planning role, entered into contractual arrangements with synchronous generators for voltage support.[578]

BOX 4: VOLTAGE CONTROL AND SYSTEM STRENGTH INCIDENTS IN VICTORIA FROM 16 TO 18 NOVEMBER 2018

Between 16 to 18 November 2018, a number of generator outages resulted in a series of directions to generators to support system voltages and levels of system strength. During this period, AEMO also switched out three high voltage transmission lines for the first time.

On 16 November 2018, AEMO made the decision to direct Newport Power Station into service to assist with voltage control to manage the potential for post-contingent voltage violations around the Keilor terminal station.

On 17 November 2018, to ensure sufficient system strength was available, AEMO required Newport Power Station to maintain its direction. To manage voltages in Victoria, a number of high voltage lines were also de-energised.

On 18 November 2018, AEMO de-energised three high-voltage transmission lines for the first time. System studies then indicated that a Mortlake unit in service on minimum generation and absorbing 100 MVAr would eliminate the post-contingent voltage violations at Keilor terminal station and system security requirements would be met. AEMO therefore directed Mortlake Power Station to manage network voltage control.

AEMO stated that these directions were prompted by periods of low demand, low prices, and synchronous plant outages. Without AEMO's intervention, these conditions would have resulted in insufficient in-service synchronous generation to maintain power system security in Victoria. AEMO also notified the market bodies that in future it will refrain from de-energisation of three 500 kV transmission lines in Victoria, and will instead direct generators to assist with voltage control. Further assessment may limit the de-energisation of high-voltage transmission lines in Victoria to one.

Source: AEMO, *System strength directions briefing*, November 2018; AEMO's market notices.
Note: 1-There are four high-voltage transmission lines in Victoria. During the incident on 18 November 2018, only the Hazelwood - South Morang No.2 line remained operated.

Given the above issues, the Panel notes that AEMO is progressing work related to voltage control under its functions as Victorian transmission network planner. AEMO's *2017 Victorian Annual Planning Report* identified a need for additional reactive support[579] to maintain transmission system voltages within operational limits during minimum demand periods.[580] In May 2018, AEMO commenced a RIT-T for increasing reactive power support to help manage voltage at times of low grid demand.[581]

578 AEMO, *2018 National transmission network development plan*, December 2018, p. 21.

579 An alternating current power system, like the NEM, operates using both active (real) and reactive power. Active power moves through the system and is delivered to consumers. Reactive power regulates voltage so active power keeps moving and the system works securely and safely.

580 AEMO is responsible for the planning of the Victorian transmission network.

581 AEMO, *Victorian reactive power support: project specification consultation report*, May 2018. For more information, see:

AEMO specified that the need for additional reactive support is driven by the following factors:[582]

- Hazelwood Power Station closed in March 2017, removing its reactive power capability to regulate voltage.
- The reduction in operational demand during light load conditions and the predicted shifting of minimum operational demand to the middle of the day.
- Expected increased penetration of large-scale renewable generation and withdrawal of thermal plants.

AEMO identified the need for additional reactive support as follows:[583]

- Maintain voltages within operational and design limits during minimum demand periods, and to maintain the power system in a satisfactory and secure operating state.[584]
- Reduce reliability[585] risk from the de-energisation of 500kV lines. The 500kV system in Victoria was not designed to operate with two or more 500kV lines out of service under pre-contingency conditions. When two or more 500kV lines are switched out of service for managing high voltages, any subsequent contingency could result in the power system losing stability, resulting in cascade tripping and large-scale interruption of consumers, even if the demand is low.
- Reduce market impact from the de-energisation of 500kV lines. De-energisation of 500 kV lines reduces Victoria's ability to export power to other regions, and may increase the need for higher marginal cost generation in other regions. AEMO's *2017 Victorian Annual Planning Report* identified that the market benefit[586] by avoiding de-energisation of a single 500 kV line could be in the range of $7 million to $26 million over the next 40 years.[587]

In July 2018, AEMO published a request for information seeking non-network options to relieve the high voltages in the Victorian transmission network during low demand periods. The request invited registered participants with equipment capable of being dispatched to suppress high voltages and located in certain areas[588] to submit a proposal to AEMO for the provision of non-market ancillary services.[589]

The next step of the RIT-T process is the full options analysis and publication of the Project Assessment Draft Report.

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

582 Ibid, p. 3.

583 Ibid, p. 6-7.

584 Refer to Chapter 4 of the NER for definitions of a satisfactory or secure operating state.

585 A reliable power system is one which has enough generation, demand-side and network capacity to supply customers.

586 From cost of fuel savings.

587 See Section 3.5 of AEMO's *2017 Victorian annual planning report*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2017/2017-VICTORIANANNUAL-PLANNING-REPORT.pdf.

588 The locations are: Moorabool, South Morang, Geelong, Sydenham or Keilor terminal stations in Victoria.

589 For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Request-for-Information-for-reactive-power-Non-market-Ancillary-Services-in-VIC

South Australia

AEMO's assessment has not identified an NSCAS gap over the next five years, as high voltages can be managed using existing plant, planned synchronous condensers, and temporary operational measures (for example, de-energising the Magill – East Terrace 275 kV cable).[590]

The system strength requirements, outlined in section 5.1.8, dictate a minimum synchronous generation dispatch in South Australia. The reactive power capability that is provided by generation to support system strength needs, and the reactive power that will be delivered by ElectraNet's planned system strength solution, is expected to support the increasing need for reactive power during low demand conditions.[591]

In its *2018 South Australian Transmission Annual Planning Report,* ElectraNet[592] reported that the minimum demand supplied by the transmission network is forecast to continue to decrease. In relation to voltage limits, ElectraNet stated the following:[593]

- A 50 MVAr, 275 kV reactor is being installed at Templers West during 2018 to prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand.
- The synchronous condensers that are planned to meet the identified system strength and potential inertia needs are expected to also enable improved system voltage control.
- A further 50 MVAr, 275 kV reactor may need to be installed between 2023 and 2028, to again prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand.

New South Wales

The closure of Liddell Power Station, together with increasing renewable generation, is likely to result in higher voltage across the New South Wales network during minimum demand periods.[594]

This increased voltage across New South Wales during minimum demand is likely to bring the existing high voltage conditions in Southern New South Wales closer to its upper limit. AEMO currently utilises six reactors and a tripping scheme in this region to manage high voltage issues under system normal conditions. AEMO stated that together with TransGrid they may need to explore other operational measures to control high voltage with higher penetration of committed renewable generation in New South Wales.[595]

Work underway

The Panel notes that AEMO recognises the need for more options to manage high voltages in the transmission network, caused by reduction in operational demand during light load

590 AEMO, *2018 National transmission network development plan*, December 2018, p. 20.

591 Ibid.

592 ElectraNet is South Australian principal transmission network service provider.

593 ElectraNet, *South Australian transmission annual planning report,* June 2018, p. 11.

594 Ibid, p. 21.

595 Ibid, p. 21.

conditions and displacement or retirement of synchronous generators together with their reactive power capabilities to regulate voltage. In response to this, AEMO has developed a work program to address challenges related to voltage control. The work program, among other things, includes:

- Collaboration with TNSPs to explore and implement short term operational measures to manage system voltages during light load conditions. This has a particular focus in Victoria at present.
- Implementation of short term non-market ancillary service contracts in Victoria, while regulatory processes continue in parallel to deliver permanent network solutions.
- Coordination of a program of work with TNSPs to collaboratively conduct system studies to identify emerging voltage control and reactive power requirements over the next 1-10 years. Development of a NEM-wide strategy for voltage management by the end of 2019.

5.1.6 System restart standard

The Panel determines the system restart standard that applies to the NEM.

The system restart standard sets out several key parameters for power system restoration, following the occurrence of a black system event.[596] The standard includes the time frame for system restoration and how much supply is to be restored. The standard provides AEMO with a target against which it procures system restart ancillary services (SRAS) from contracted SRAS providers.

In December 2016, the Panel completed the review of the system restart standard. The final standard commenced on 1 July 2018. The Panel introduced some changes to the system restart standard. The key changes made to the standard include:[597]

- tailoring the level and time components of the system restart standard for each electrical sub-network to reflect the speed at which the generation can be restored, the characteristics of the transmission network and the economic circumstances that apply to the sub-network
- specifying the minimum level of generation and transmission capacity to be restored by system restart ancillary services in each sub-network in accordance with a detailed economic assessment of procuring different levels of system restart ancillary services
- including aggregate reliability of the system restart ancillary services procured for each of the electrical sub-networks. This requirement of the system restart standard better specifies the performance of the procured system restart ancillary service, and includes a requirement for AEMO to consider the reliability of the transmission network, following a major supply disruption, when it calculates aggregate reliability.

In September 2017, the AEMC made the *Generating system model guidelines* rule, which requires prospective SRAS providers to provide AEMO with sufficient data, models and parameters of relevant generators in accordance with the requirements described in the

596 Clause 8.8.3(aa) of the rules.

597 For mere information, see: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-system-restart-standard

rules.[598] In February 2018, the AEMC published the *System restart plan provisions* rule, which provides AEMO with greater regulatory certainty in disclosing the system restart plan to certain parties for the purposes of preparing for, and participating in, system restoration during a major supply disruption.[599] In March 2018, the AEMC also published the *Testing of system restart ancillary services capability* rule, which exempts generators from notifying network service providers about a short notice test of SRAS capability. Instead, AEMO now works directly with network service providers to plan the test date.[600]

Over 2017/18, AEMO undertook a procurement process to acquire SRAS for the period starting 1 July 2018, in accordance with the SRAS Guideline published by AEMO in December 2017. A competitive tender process was conducted for all electrical sub-networks other than Tasmania.[601] All new contracts are for a three-year duration, with options to extend by up to one year at AEMO's discretion, and up to a further year by agreement. Table 5.12 compares actual SRAS costs[602] between 2015/16 and 2017/18. It also demonstrates estimated costs of SRAS for 2018/19 (new contracts).

598 The requirements are described in clause 3.11.9(g) of the NER. For more information, see: https://www.aemc.gov.au/rule-changes/generating-system-model-guidelines

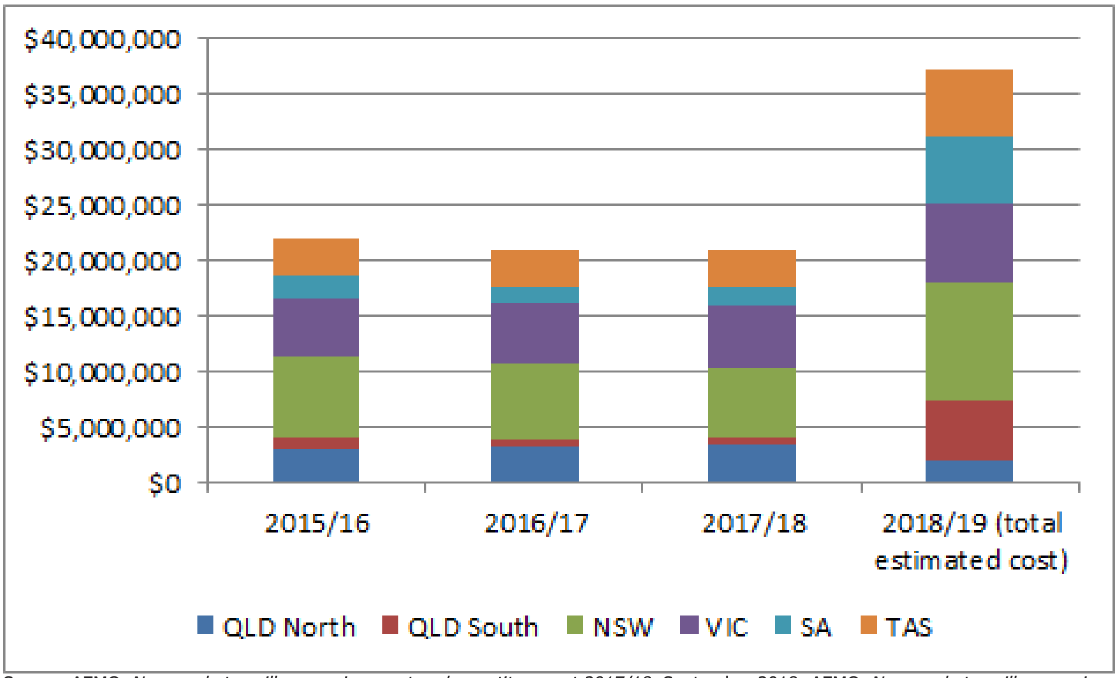
599 For more information see: https://www.aemc.gov.au/rule-changes/system-restart-plan-release-provisions

600 For more information see: https://www.aemc.gov.au/rule-changes/testing-of-system-restart-ancillary-services-capab

601 As there is only one possible SRAS provider for Tasmania, AEMO directly requested offers from that provider.

602 The annual cost of SRAS is based on an aggregation of payments to contracted providers for: availability ($ per 30-minute trading interval), testing (fixed amount per successful test) and usage (fixed amount if the service is used in the event of a blackout).

Figure 5.12: SRAS costs



Source: AEMO, *Non-market ancillary services cost and quantity report 2017/18,* September 2018; AEMO, *Non-market ancillary services cost and quantity report 2016/17,* September 2017; AEMO, *Non-market ancillary services cost and quantity report 2015/16,* September 2016.

Note: AEMO notes that a conservative approach was adopted to calculate total estimated SRAS costs for 2018/19. For the calculation of estimated availability costs 100 per cent availability for each service was assumed. This is likely to be less due to outages.

To date, AEMO drew on SRAS only once - to restore supply in South Australia following the black system event in September 2016. In *2017 AMPR*, the Panel has discussed the function of SRAS during the event. Further, on 14 December, the AER published its *Black system event compliance report.* The findings of this report will be discussed in the 2019 AMPR.

5.1.7 Constraints

A constraint is a limit that is imposed in the NEM dispatch engine, which is a linear program that AEMO uses to determine the optimal pattern of generation dispatch. It is effectively a mathematical representation of a physical limit that exists on the power system, which is used to change the pattern of dispatch determined by NEMDE. The net result of this limit, in terms of how it translates into changes in generation dispatch, is commonly called 'congestion'.

The application of these constraint equations to the process of dispatch can have an impact on pricing in the electricity market.

AEMO publishes a report every year which examines some key impacts from the application of these constraints in dispatch. The key findings of the *NEM Constraint Report 2017* included:[603]

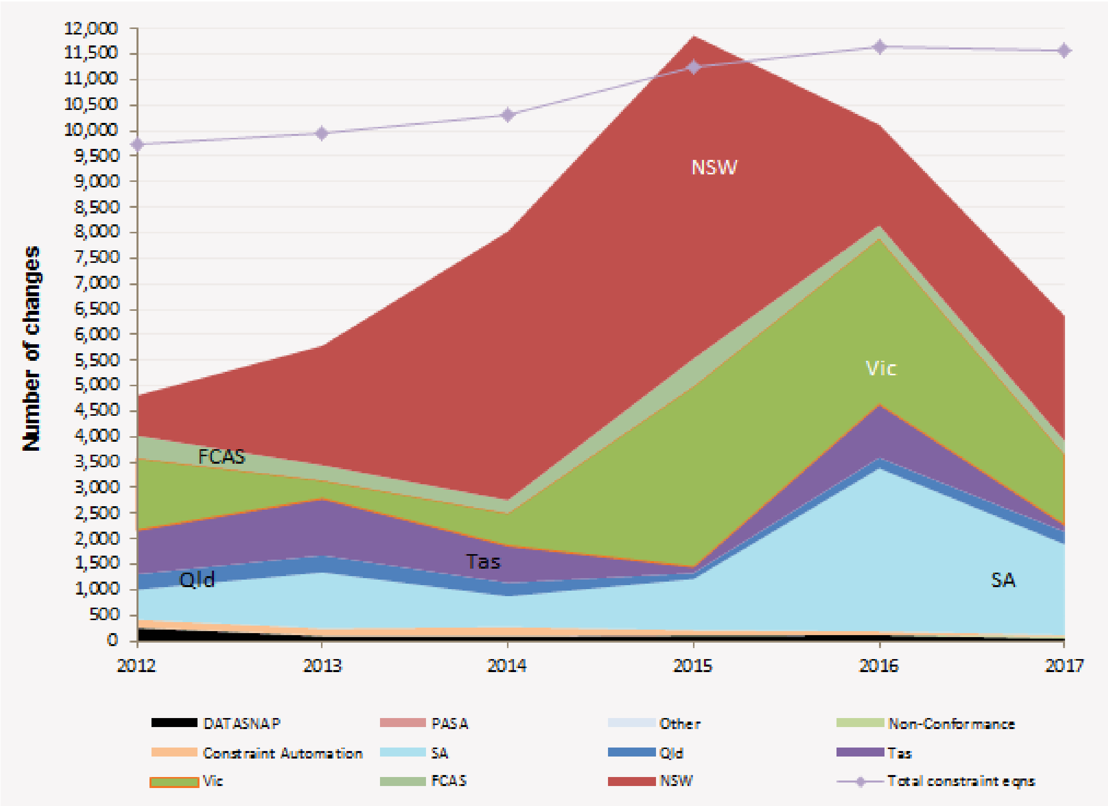
- The main driver for either updating or creating new constraint equations is a physical change in the power system. These changes are likely to be associated with the addition of, or removal of, either generation or transmission assets. In 2017, the number of constraint equation changes decreased significantly in comparison to 2016, from 10,477 to 6,756. This was mostly due to the decreases in the number of constraint equation changes in Victoria, South Australia and Tasmania (see Figure 5.13). This demonstrates that in 2017 the power system experienced fewer changes than in 2016 and 2015. The major contributor to the high number of constraint equation changes in 2016 was the Heywood Interconnector upgrade project in South Australia.[604] The major contributors to the high number in 2015 were generator changes in New South Wales and Victoria.[605] AEMO expects that the number of constraint equation changes will materially increase with the volumes of new generation entering the NEM.

603 AEMO, *NEM Constraint report - electronic summary data*, July 2018.

604 Reliability Panel, *2017 Annual market performance review*, March 2018, p. 94.

605 AEMO, *NEM Constraint report 2015*, June 2016, p. 6.

Figure 5.13: Constraint changes by region and year

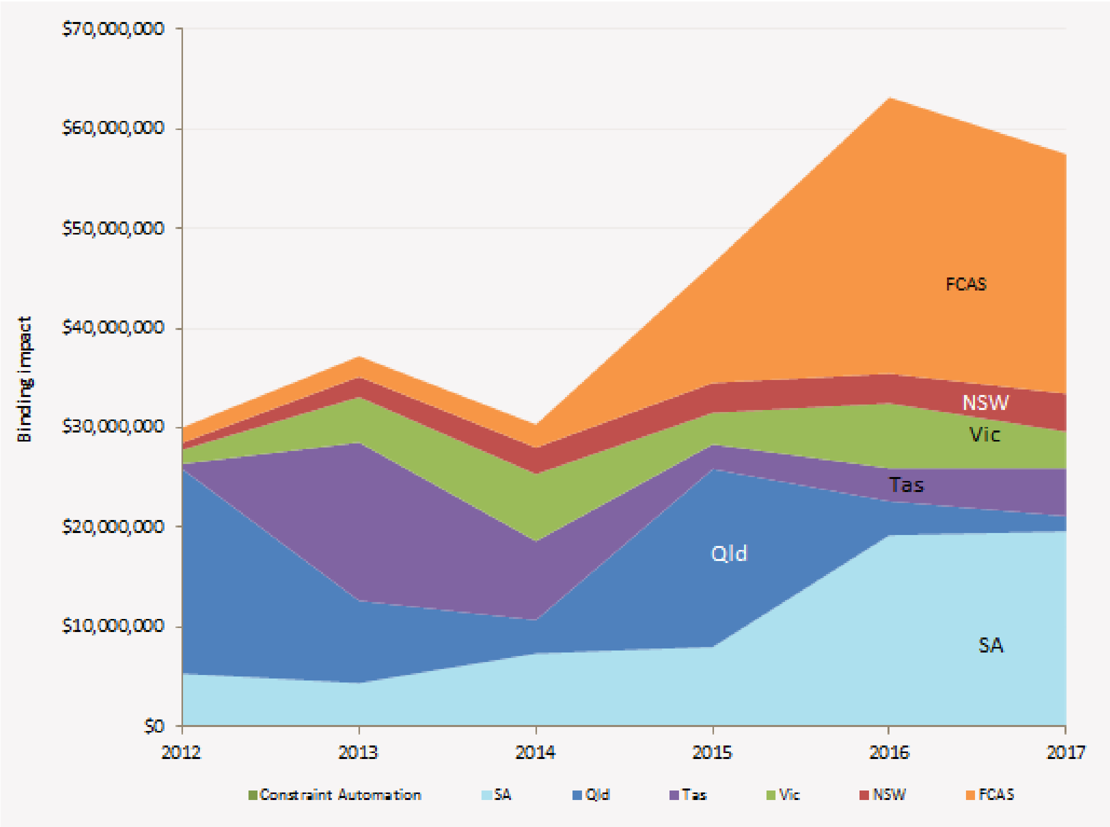


Source: AEMO, *NEM Constraint Report 2017 summary data,* July 2018.

- The total cumulative marginal value[606] of constraints decreased from $63 million in 2016 to $57 million in 2017. Figure 5.14 shows that the change in the total cumulative marginal value of all constraints could be mainly attributed to the decrease in the cumulative marginal value of FCAS constraints between 2016 and 2017. Nevertheless, as a proportion of the total cumulative marginal value of all constraints, FCAS constraints are still the largest component, and has increased markedly since 2014.

606 Every dispatch interval, NEMDE provides the marginal value of every constraint used in the dispatch process. The marginal value of a constraint is the effect on total dispatch costs of alleviating that constraint by 1 MW. Summing the marginal values of a constraint over a time period gives an indication of the cumulative marginal value of the constraint over the time period. It is important to remember that the cumulative marginal value measures the only marginal cost of a constraint, and not the total cost. For example, in a given dispatch interval the marginal value of a constraint might be $10,000 per MW. This does not mean that alleviating the constraint by 10 MW will yield a benefit of $100,000 – the marginal cost may fall rapidly as the constraint is alleviated, and may even fall to zero, which means the constraint is no longer binding.

Figure 5.14: Binding impact of constraints



Source: AEMO, *NEM Constraint Report 2017,* July 2018.

More information on constraints is provided in appendix G. Constraints to manage system strength in South Australia are discussed in section 5.1.8. Inter-regional constraints on the interconnectors are discussed in chapter 3.

5.1.8 System Strength

System strength is a property of the power system that resists changes in voltage in response to a change in loading conditions. It is also related to the level of current that can flow into a short circuit at a particular point in the power system, with low system strength conditions corresponding to low levels of available fault current. This availability of fault current affects the ability of system protection systems to operate correctly and the stability and dynamics of generator control systems.

System strength is supported by synchronous generating systems or other equipment, such as synchronous condensers, that are able to supply fault current. To date, asynchronous, inverter connected generating systems have not provided fault current to support system strength.

Accordingly, system strength is often lowest in areas of the power system with low levels of local synchronous generation either connected or online, and may deteriorate further as more asynchronous, inverter-based generation is connected.[607]

Declining levels of system strength can lead to localised issues and can also have broader power system impacts. The potential challenges for the power system associated with decreasing levels of system strength include:[608]

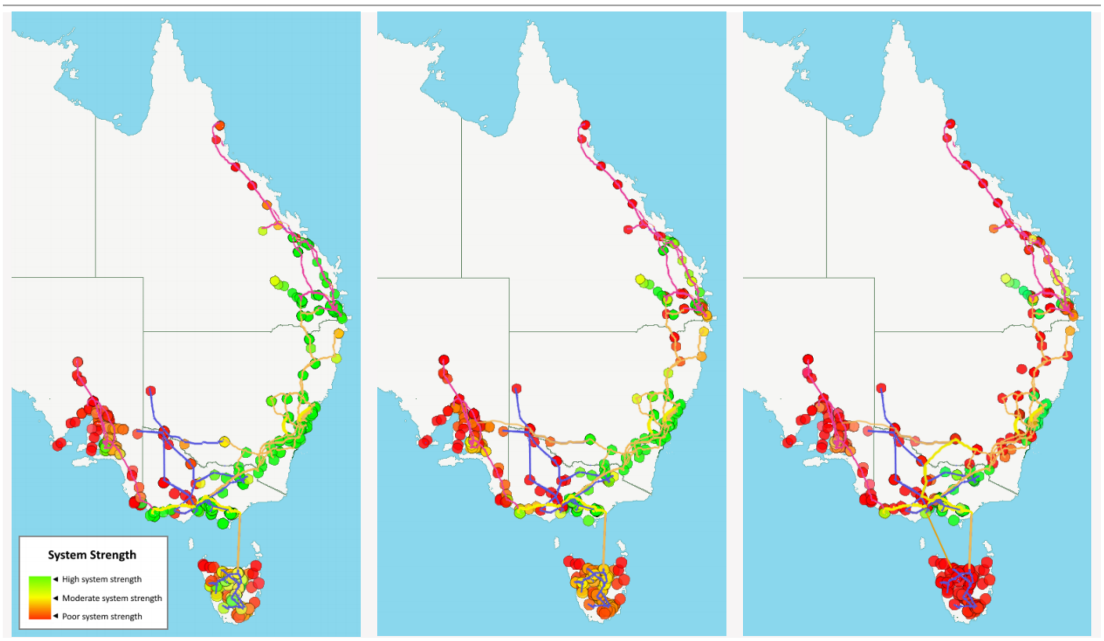
- In systems with low system strength, greater deviations in voltages occur due to disturbances, such as a fault on the network. In a weak network area, voltage dips are deeper, more widespread, and can last longer than in a strong network.
- The width and depth of these voltage disturbances can be exacerbated in those parts of the power system where there is a lack of reactive capability due to reduced synchronous plant online. This can lead to difficulty in maintaining secure operating voltages.
- In a weak system, where the impact of the network faults can be deeper and more widespread, a large amount of asynchronous generation can enter fault ride-through mode during the brief period before a fault is isolated, resulting in an active power imbalance.
- For the same consumer demand, voltage harmonics and imbalance are generally higher in weak systems than in strong systems. Because synchronous generators dampen harmonics and voltage imbalance, displacement of synchronous generators with inverter-connected generation diminishes power quality.
- The trend of decreasing system strength will result in fault current being reduced, which makes it more difficult for protection systems to detect and isolate faults.

The Panel also notes that system strength is a local issue and fault levels generally must be supplied locally. Solutions to improve system strength include synchronous condensers, synchronous generators, and asynchronous generation with grid-forming inverters.[609]

A projection of estimated future levels of system strength is shown in Figure 5.15. The figure shows that, currently, there is low system strength at the fringes of the grid, particularly in north Queensland, south-west New South Wales, north-western Victoria, and South Australia. This figure also shows that levels of system strength are projected to worsen over the next 20 years, in the absence of any remediation actions by generators or networks.[610]

607 Ibid.
608 Ibid.
609 Ibid, p. 73.
610 Ibid.

Figure 5.15: Projected system strength assessments for 2018-19 (left), 2028-29 (middle), and 2038-39 (right)



Source: AEMO, *Integrated System Plan*, July 2018.

The Panel notes that in September 2017, the AEMC published the *Managing power system fault levels* rule. Obligations under the rule commenced in South Australia on 13 October 2017, and on 1 July 2018 in the rest of the NEM. The rule places an obligation on:[611]

- Transmission network service providers (TNSP) to maintain minimum levels of system strength. The framework in the final rule clearly allocates responsibility for system strength to the party who is best placed to manage the risks associated with fulfilling that responsibility – that is, the relevant TNSP. Should a shortfall be identified by AEMO, the TNSP must procure system strength services to maintain the fault levels determined by AEMO. AEMO has published methodologies and assessments relating to these TNSP responsibilities to maintain minimum fault levels at specific fault level nodes.[612]
- New connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system. When a new generator is negotiating its connection with the relevant network service provider (NSP), a system strength impact assessment is required to be undertaken by the NSP to assess the impact of the connection of the generating system on the ability of the power system to maintain stability in accordance with the NER, and for other generating systems to maintain stable

611 For more information, see: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

612 AEMO, *System strength requirements methodology, 2018 System strength requirements & fault level shortfalls,* 29 June 2018, available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review

operation including following any credible contingency event or protected event. The new connecting generator would be required to fund the provision of any required system strength services to address the impact of its connection on system strength.[613] AEMO notes that many renewable developments contemplated in the 2020s are likely to require some level of system strength remediation.[614]

System strength in South Australia

Network Support and Control Ancillary Services (NSCAS) are non-market ancillary services designed to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network. While NSPs are responsible for procuring network support services generally, AEMO is responsible for assessing the adequacy of these services, and can declare a "NSCAS gap" where it determines further services are needed.

AEMO identified an NSCAS gap in South Australia for system strength in the *2016 National transmission network development plan* (NTNDP)[615], and confirmed this gap in subsequent updates in September 2017[616] and October 2017[617]. ElectraNet has agreed to meet this gap under the minimum system strength framework discussed above.[618] Further, in *2018 NTNDP*, AEMO declared an inertia shortfall in South Australia.[619]

To address the system strength issue, ElectraNet determined that the installation of synchronous condensers on the network is the most efficient and least cost option.[620] ElectraNet plans to deliver a solution to improve system strength in South Australia by end 2020.[621] To address the inertia shortfall, AEMO also recommended that ElectraNet fit flywheels to the proposed synchronous condensers and consider opportunities for developments that provide fast frequency response.[622]

Until these measures are in force, to manage the security of the system AEMO will continue to use the following main instruments to manage system strength in South Australia:

- **Directions:** to direct synchronous machines to synchronise or remain online to maintain sufficient system strength in South Australia and thereby maintain the grid in a secure operating state. System strength directions in South Australia are discussed in more detail in section 5.1.9.

613 This already could be observed in north-west Victoria, where Total-Eren agreed to install a synchronous condenser with its 200 MW Kiamal Solar Farm to avoid significant curtailment issues. For more information, see: https://new.siemens.com/au/en/company/press-centre/2018/first-solar-farm-synchronous-condenser.html

614 AEMO, *Integrated system plan*, July 2018, p. 72.

615 AEMO, *2016 National transmission network development plan*, December 2016, p. 8.

616 AEMO, *Update to the 2016 NTNDP*, September 2017, p. 3.

617 AEMO, *Second update to the 2016 NTNDP*, October 2017, p. 3.

618 ElectraNet, *Strengthening South Australia's power system*, accessed on 21 November 2018, available at: https://www.electranet.com.au/what-we-do/projects/power-system-strength/

619 AEMO, *2018 National transmission network development plan*, December 2018, p. 4. Inertia shortfalls are identified by AEMO, and actioned by NSPs, through a process separate to the NSCAS framework.

620 Ibid, p. 16.

621 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 5.

622 AEMO, *2018 National transmission network development plan*, December 2018, p.12.

- **Constraints:** to curtail the amount of asynchronous generation that is generating at any point in time.[623] The constraints act to constrain the amount of wind generation to a level that can be accommodated while ensuring system strength remains adequate. That is, currently system strength is a function of synchronous units online. Asynchronous generation above certain limits is constrained to reach the required minimum security limit. Increased total generation leads to the relaxation of constraints.

In July 2017, AEMO introduced a system strength constraint in South Australia.[624] The new constraint initially had the effect of curtailing total asynchronous South Australian generation output to 1,200 MW, to meet a minimum system strength requirement. In December 2017, AEMO announced this curtailment limit had been increased from 1,200 MW to 1,295 MW.[625] More recently, AEMO has applied a regional constraint to limit the aggregate level of asynchronous generation output in South Australia to levels typically between 1,295 MW and 1,460 MW, unless a minimum level of synchronous generation is dispatched.[626]

Figure 5.16 demonstrates the levels of asynchronous generation curtailment[627] in South Australia from Q2 2017 to Q2 2018.

The Panel notes that the total curtailment of asynchronous generation during Q3 2018 (not shown in the graph below) was the highest amount on record, at around 150 GWh or 10 per cent of available South Australian asynchronous generation. According to AEMO, the key driver of this was insufficient synchronous generators online on top of the minimum requirement to enable wind to generate.

623 The Panel notes that not all asynchronous units are impacted. For instance, the Hornsdale Power Reserve is not curtailed.

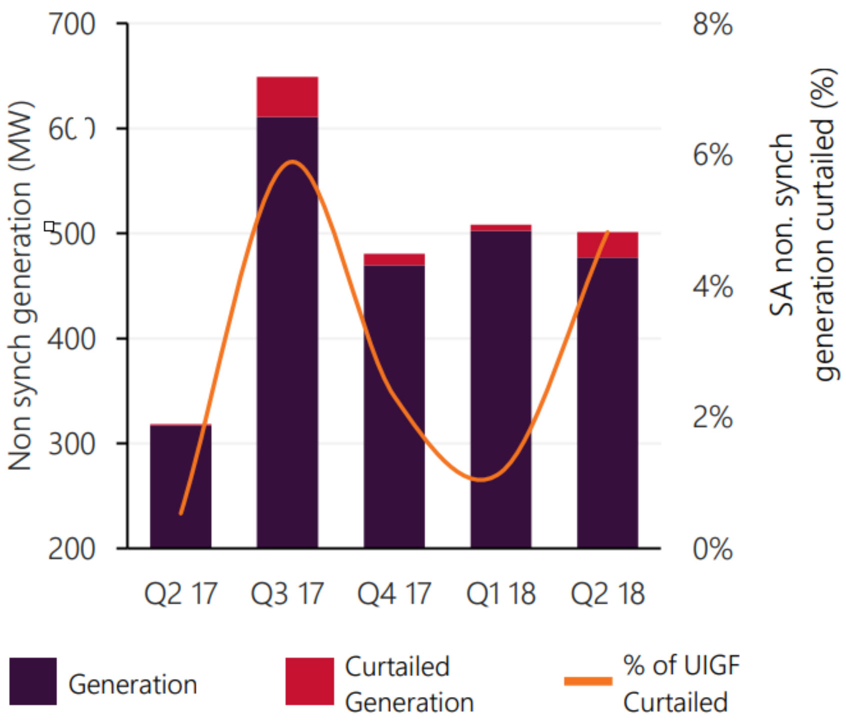
624 To address system strength in South Australia, AEMO applied the S_WIND_1200_AUTO and S_NIL_STRENGTH_1 constraints.

625 AEMO, *Transfer limit advice – South Australian system strength*, December 2017, p. 7.

626 ElectraNet, *Addressing the system strength gap in SA*, economic evaluation report, February 2019, p. 12. For more information, also see: AEMO, *Transfer limit advice – South Australia system strength*, Version 19, 5 December 2018, available at: http://https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestioninformation/Limits-advice

627 This figure is based on AEMO's unconstrained intermittent generation forecast (UIGF). AEMO is required to prepare forecasts of the available capacity of semi-scheduled generators, in order to schedule sufficient generation in the dispatch process. This is known as the UIGF. AEMO estimates UIGF based on the outputs of the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting

Figure 5.16: Curtailment of SA asynchronous generation



Source: AEMO, *Quarterly Energy Dynamics*, Q2 2018.

Note: This figure is based on AEMO's unconstrained intermittent generation forecast (UIGF). AEMO is required to prepare forecasts of the available capacity of semi-scheduled generators, in order to schedule sufficient generation in the dispatch process. This is known as the UIGF. AEMO estimates UIGF based on the outputs of the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). For more information, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting

The Panel recognises there may be material costs for consumers associated with the application of these system strength constraints in South Australia. This is because the application of these constraints to keep the system in a secure operating state also has the effect of increasing wholesale market prices. By restricting output from asynchronous generators, which traditionally bid into the market at low prices, market prices are likely to be higher, due to the fact that synchronous generators with higher marginal costs will remain online at times when they would (but for the constraints) be displaced by low cost wind output.

The Panel's analysis of the system strength constraints in South Australia demonstrates that the marginal values[628] of inidividual constraints, per event, are not high, as compared to the marginal values of other inidividual system normal constraints.[629] However, the fact that these constraints occur very frequently results in a relatively high cumulative marginal value. Therefore, in 2017, system strength constraints had the highest cumulative marginal value of all system normal constraints, which include both constraints managing power flows within the system and constraints setting limits on interconectors. According to AEMO, in the 2017 calendar year the cumulative marginal value of system strength constraints in South Australia was $4.75 million.[630]

Other costs associated with the measures being taken to address system strength issues in South Australia are discussed further below.

5.1.9 Power system directions and instructions

AEMO may issue a direction[631] or an instruction[632] to registered participants where it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state.[633]

A registered participant must use its reasonable endeavours to comply with a direction regardless of the financial implications including potential losses - unless to do so would, in their reasonable opinion, be a hazard to public safety, materially risk damaging equipment, or contravene any other law.[634]

The use of directions has increased markedly over the last year, with an increase in both the number and duration of direction events. Figure 5.17 presents the number of direction events since 2006/07. It shows that:

- The number of direction events in 2017/18 was the highest of the past 10 years. The number of direction events was four times higher than in the past financial year (32 in 2017/18 compared to eight in 2016/17).
- All but one of the direction events in 2017/18 occurred in South Australia.

628 Every dispatch interval, NEMDE provides the marginal value of every constraint used in the dispatch process. The marginal value of a constraint is the effect on total dispatch costs of alleviating that constraint by 1 MW. Summing the marginal values of a constraint over some time period gives an indication of the wholesale market impact of the constraint over the time period. This is called the cumulative marginal cost of the constraint. It is important to remember that this measure considers only the marginal cost of a constraint, and not the total cost. For example, in a given dispatch interval the marginal value of a constraint might be $10,000 per MW. This does not mean that alleviating the constraint by 10 MW will yield a benefit of $100,000 – the marginal cost may fall rapidly as the constraint is alleviated, and may even fall to zero, which means the constraint is no longer binding.

629 System normal constraints are those that reflect the operation of the system in its standard operating configuration, that is, they do not include constraints caused by outages of transmission elements.

630 AEMO, *NEM constraint report 2017 summary data*, July 2018.

631 For example, if there is a risk to the secure or reliable operation of the power system, AEMO can direct a generator to increase (or decrease) its output unless (in the Registered Participant's reasonable opinion) it would be a hazard to public safety, materially risk damaging equipment or contravene any other law. Clause 4.8.9(c) of the NER.

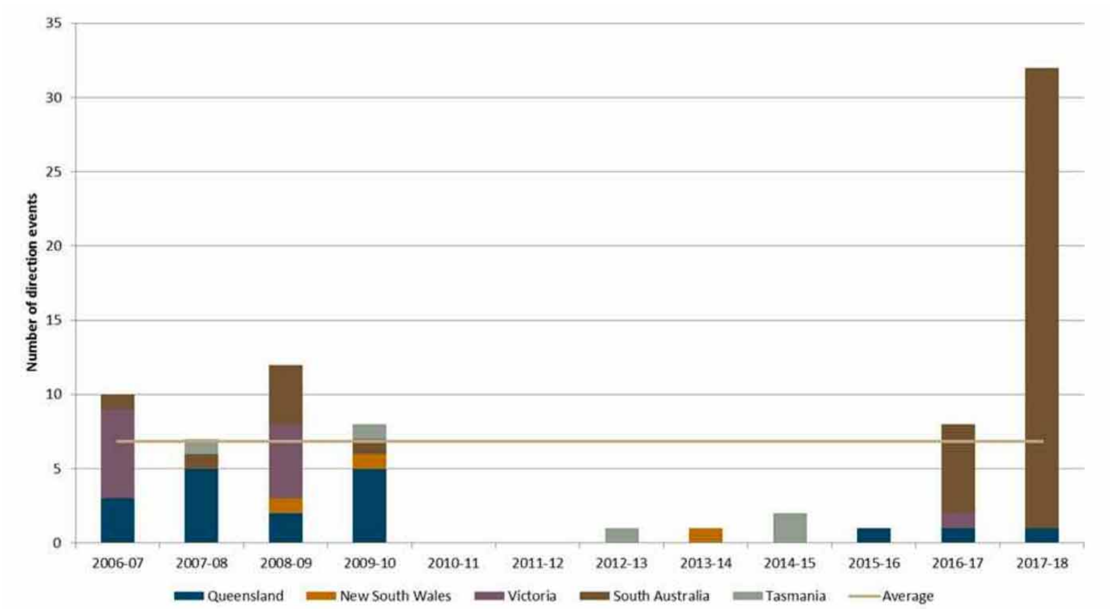
632 Instructions generally involve AEMO requiring a network service provider or a large energy user to shed load (under clause 4.8.9(a) and 4.8.9(a1)(2) of the NER). Since April 2016, AEMO has issued only two instructions resulting in load shedding. Both of them were in February 2017.

633 Clause 4.8.9(a)(1) of the NER.

634 Clause 4.8.9(c) of the NER.

- Over the past two years almost all direction events involved maintaining the system in a secure operating state (38 of 40 events). Only two direction events were to maintain the system in a reliable operating state.

Figure 5.17: Direction events in the NEM



Source: AEMO.

The Panel notes that a direction event may include multiple individual directions to different generators.[635] For instance, between 23 April and 14 May 2018 (a 21 day period) a single direction event occurred in South Australia. Within this single direction event, 27 individual directions were issued to market participants to maintain power system security. AEMO notified the Panel that in 2017/18 it issued a total of 101 individual power system security directions.[636] This is the highest number over the past 10 years. For comparison, in 2016/17, eight power system security directions were issued.

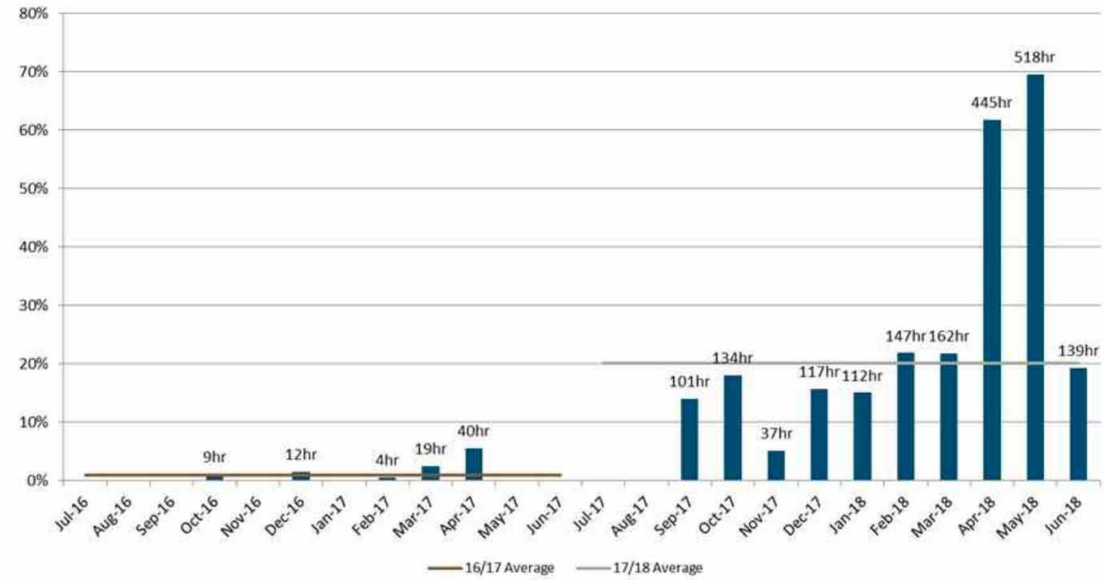
The proportion of time in which directions have been in place in the NEM has also risen noticeably over the last year. Figure 5.18 presents the percentage of time per month that directions were in place since July 2016. For 2017/18, a direction event was in force in the NEM on average approximately 20 per cent of the time, up from one per cent in 2016/17. Notably, directions were in force for over 60 per cent of the time during April and May 2018. That is, in 2017/18 directions were in place on average 159 hours per month; in 2016/17 the average figure was seven hours per month.[637]

635 A direction event is not a defined term in the NER. There is no prescribed method, by which to determine the appropriate length of AEMO direction events. These can range from a few hours to, in one case, 21 days (in April-May 2018).

636 The increase in directions issued could be attributed to the fact that in South Australia certain combinations of synchronous generators must be in service at all times. This is discussed further in this section.

637 AEMC, *Reliability frameworks review*, final report, July 2018, p. 97.

Figure 5.18: Percentage of time in each month direction was in force



Source: AEMC, *Reliability frameworks review*, final report, July 2018.
Note: The percentage calculations are based on the total number of hours per month, which varies month to month. The assumptions made regarding how directions are grouped may affect total monthly hours.

Directions in South Australia

Most of the directions that account for the increased number of directions in the reporting period were to ensure adequate system strength for secure operation of the South Australian power system.

In South Australia, certain combinations of synchronous generators must be in service at all times to maintain sufficient levels of system strength. In September 2017, AEMO published the *South Australia system strength assessment,* where it was identified that a more complex arrangement of synchronous machines must remain online, to maintain sufficient system strength for various asynchronous generation dispatch levels in South Australia.[638] When AEMO determines that this power system security requirement will not be met, AEMO issues a direction to one or more synchronous generators to synchronise or remain synchronised.

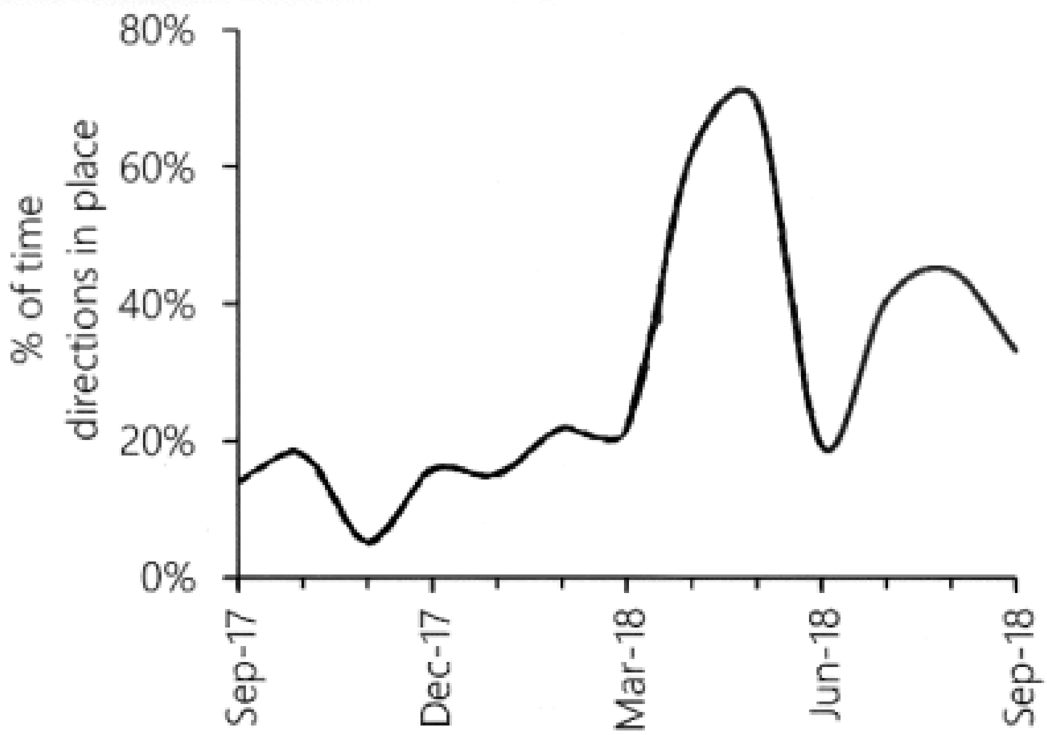
AEMO continues to investigate system strength requirements in South Australia, and updates the set of viable combinations on a regular basis. The most recent summary of synchronous generation combinations that would provide sufficient system strength at different asynchronous generation levels was published in December 2018.[639]

638 An initial minimum system strength requirement was equivalent to the two largest synchronous machines to remain online at all times.

639 See: AEMO, *Transfer limit advice - South Australian system strength*, December 2018.

AEMO notes that on average, system strength directions were in place for around 40 per cent of the time during Q3 2018, 50 per cent of the time in Q2 2018 and 30 per cent in the period since the system strength unit combinations were introduced in September 2017 (see Figure 5.19).[640]

Figure 5.19: Directions for system strength in South Australia



Source: AEMO, *Quarterly energy dynamics*, Q3 2018.

AEMO recognised the following key drivers of system strength directions during the quarters:[641]

- **Q2 2018:** System strength directions were driven by high wind generation output, lower operational demand and generator outages, including at Pelican Point.
- **Q3 2018:** Key drivers during the quarter included periods of relatively low prices (<$50/MWh) and high wind output (>1,100 MW), which resulted in synchronous generators seeking to de-commit from the market for commercial reasons.

640 AEMO, *Quarterly energy dynamics*, Q3 2018, p. 7.

641 AEMO, *Quarterly energy dynamics*, Q2 2018 (p. 6) and Q3 2018 (p. 7).

These interventions impose material costs on consumers. According to AEMO, the cost[642] of the system strength directions was $7.05 million in Q2 2018 and $7.4 million in Q3 2018.[643] ElectraNet also stated that ongoing direction compensation costs are currently estimated to be approximately $34 million per annum in net terms (equivalent to around $3 million per month).[644] This excludes the broader impact of intervention pricing[645] on wholesale market prices through AEMO's direction process, which represents an additional cost ultimately borne by customers. In its *Addressing the system strength gap in SA* report, ElectraNet stated that the cost impact of intervention pricing on wholesale market outcomes as a result of issuing directions for system strength as at September 2018[646] exceeds $270 million.[647] This is additional to the impacts of constraining wind generation.[648]

In addition to the directions being issued in South Australia, system strength related issues are emerging in other regions of the NEM. For example, on 17 November 2018, AEMO issued a direction in Victoria to maintain sufficient system strength. To date, AEMO has not declared a shortfall in system strength in any NEM region other than South Australia. However, the recent direction in Victoria may indicate an emerging system strength issue in that region and could potentially be an indication of nascent system strength issues throughout the rest of the NEM.

System strength shortfalls can be expected to continue as existing synchronous generators retire and as installation of residential scale solar continues to grow. This is because residential rooftop PV reduces operational demand, which impacts on spot prices and can

642 Based on Compensation Recovery Amount (provisional amount). Compensation Recovery Amount is recovered from the NEM for a direction. It is equal to the sum of the compensation amount paid by AEMO to directed generators, the independent expert fee and interest amount. Interest is determined at the average bank bill rate between the settlement date corresponding to the direction date and the settlement date of the final determination week. AEMO, *NEM direction compensation recovery*, January 2015.

643 AEMO, *Quarterly energy dynamics*, Q3 2018, p. 7.

644 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 20. The cost of $34 million does not represent the total cost of directing generators in South Australia to ensure adequate system strength. It is also appropriate to take into account trading amounts that would otherwise be paid to those generators and wider impacts on wholesale market prices. This is discussed in more detail in Chapter 7 of the consultation paper for the AEMC's *Investigation into intervention mechanisms and system strength in the NEM*. Source: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

645 Where a direction has been issued, AEMO will apply intervention pricing in accordance with its Intervention Pricing Methodology. Intervention pricing is triggered when AEMO intervenes in the market by activating the RERT or issuing a direction. Intervention pricing determines the price at which the market clears during an AEMO intervention event, while compensation is a separate process and is paid only to certain parties – those who are directed to provide services and those who are affected (i.e. dispatched differently) due to the direction. Compensation is payable regardless of whether intervention pricing is implemented.

646 While the basis on which this figure is calculated is not set out in the report, the Panel understands that it reflects the difference between spot prices as set by the intervention pricing run and prices produced by the dispatch run, averaged over the period April 2017 to September 2018.

647 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 21. While the basis of this $270 million figure is not set out in the ElectraNet report, the Panel surmises that it reflects the difference between spot prices as set by the "intervention pricing run" and prices produced by the "dispatch run" when system strength directions are in effect, averaged over the period from April 2017 to September 2018. If this is the case, it is likely that this figure represents an upper limit of the impact of intervention pricing on wholesale energy prices. This is because the market could be expected to self-correct at least to some degree if intervention pricing was not applied and prices were allowed to fall in response to additional generation coming online in response to a system strength direction. For example, in South Australia, removing intervention pricing and allowing the spot price to fall to reflect the supply demand balance that follows from the direction could be expected to prompt generators to rebid or withdraw from the market rather than pay to generate when prices fall to strongly negative levels. Secondly, higher spot prices typically do not translate immediately or directly into higher prices for consumers. This is because most retailers have hedge contracts with generators in order to manage wholesale price volatility. However, contract prices are negotiated having regard for expectations about future spot prices. As such, higher spot prices can be expected to put upward pressure on contract prices and thus wholesale energy costs. For more information, see: AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, April 2019.

648 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 21.

therefore act to displace synchronous generators in dispatch, reducing the available supply of fault current from synchronous generation.

Similarly, increased penetration of new large scale asynchronous generation (which usually has lower short run variable costs than traditional forms of synchronous generation) can be expected to exacerbate this displacement effect, increasing the extent of this system strength shortfall.[649]

The list of all directions, including system strength directions in South Australia, is included in appendix G. System strength in South Australia and, specifically, curtailment of asynchronous generators are discussed in more detail in section 5.1.8.

Direction in Queensland

In 2017/18, apart from system strength directions in South Australia, there was one direction in Queensland on 22 May 2018. At 10.01 multiple network elements at the Ross substation in north Queensland tripped simultaneously. Following the non-credible contingency event, a constraint equation invoked by AEMO was violated, and could only be alleviated by increased generation from north Queensland. Eligible participants indicated they did not intend to adjust their market offers, but identified generators that would be available if directed. AEMO issued a direction to Origin Energy Limited for Mt Stuart gas turbines unit 1 & 2 to synchronise and follow dispatch targets. Intervention pricing was not applied for this event.[650]

5.2 Major system security events

As the Panel noted earlier in the report, in 2017/18 there was one instance of the system not operating in a secure state for greater than 30 minutes. This event followed switching actions taken to manage contingency overloads indicated after a transformer failure in Victoria on 18 January 2018.

The power system security issue was localised, and was identified by AEMO after a post-event review. Contingency analysis tools did not identify the issue at the time because the configuration of relevant equipment was not accurately reflected in AEMO's models. AEMO has since reviewed the modelling for all similar substations in the region.[651] More details on the event are provided in section 5.1.1.

A major system security event occurred on 25 August 2018 (2018/19 financial year), which falls outside of the reporting period for this AMPR. However, the Panel has included some high level analysis of this event in this report to illustrate the extent of potential supply and cost impacts for consumers following major security events in the power system. The event will be discussed in more detail in the 2019 AMPR.

649 However, it should also be noted that the connection of these generators themselves should not directly impact the size of a system strength given the 'do no harm' obligation introduced by the AEMC as part of the Managing power system fault levels rule change. The 'do no harm' obligation introduced by the AEMC is discussed further in this report.

650 AEMO, *NEM event - direction 22 May 2018*, October 2018, p. 4.

651 The Panel notes that at a time of publication of this report, the incident report for this event was not yet published by AEMO.

The event description below draws heavily on the relevant AEMO incident report.[652]

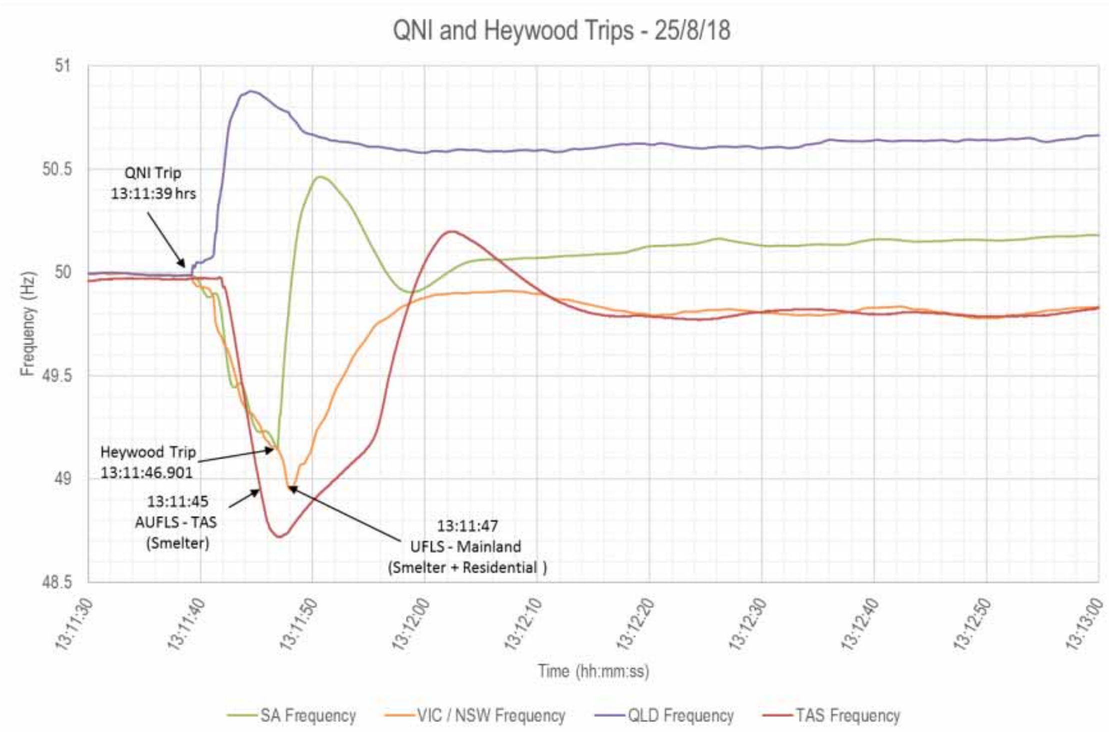
Key details

- On Saturday 25 August 2018, at 13:11, the New South Wales-Queensland Interconnector (QNI) tripped, separating Queensland from the rest of the NEM. Powerlink advised AEMO that it had found evidence of a flashover consistent with a lightning strike at the fault location.[653]
- The QNI trip caused power system frequency to drop in New South Wales, Victoria and South Australia (see Figure 5.20). This frequency drop, combined with changes in the power flow on the Heywood Interconnector, led to the activation of the Heywood Emergency Control Scheme and separation of South Australia from Victoria.
- This separation caused a further reduction in power system frequency in Victoria and New South Wales, which triggered emergency UFLS in these regions to restore the balance of supply and demand.
- In response to the decline in frequency on the mainland, the Basslink Interconnector automatically increased power transfer from Tasmania to Victoria to support mainland frequency, as designed, causing frequency to fall in Tasmania. Tasmania's Adaptive UFLS scheme then automatically operated to disconnect contracted interruptible industrial load.
- In total, there was approximately 997.3 MW of under-frequency load shedding in Victoria and New South Wales.
- Re-synchronisation of South Australia to Victoria occurred at 13:35, followed by Queensland to New South Wales at 14:20. All load was restored by 15:28.

652 For more information, see: AEMO, *Preliminary report - Queensland and South Australia system separation on 25 August 2018*, September 2018 and AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018*, September 2018.

653 QNI comprises two circuits strung on single tower structures. Prior to this event, QNI was not considered vulnerable to lightning as there was no 'probable' risk of simultaneous strikes impacting both lines.

Figure 5.20: Regional frequency during the separation events on 25 August 2018



Source: AEMO, *Preliminary Report - Queensland and South Australia system separation on 25 August 2018*, September 2018.

Costs associated with the event

The market impacts of the event included:

- The South Australia wholesale market spot price reduced to around -$450/MWh, due to the loss of export to Victoria, which caused a temporary excess of supply in South Australia. Prices rapidly recovered to pre-event levels.
- Queensland's energy price increased to around $1,400/MWh for a single dispatch interval.
- More than $10 million in FCAS costs were incurred – all mainland regions recorded FCAS prices at the price cap of $14,500/MWh.

No information is yet available on the total cost to consumers from the load shedding associated with the event.

AEMO recommendations

AEMO has identified that the operating incident that occurred in the NEM on 25 August 2018 was a significant system event and, while most power system equipment operated within the standards set under the NER, AEMO's view is that the aggregated response did not meet expectations for power system resilience. AEMO's analysis highlights a decline in frequency control capability and system resilience to events larger than single credible contingencies in the NEM. AEMO considers this an immediate risk to the power system.[654]

AEMO also stated that the occurrence of this event demonstrated a substantial reliance on automatic load shedding to rebalance supply and demand following contingency events in excess of the single largest credible contingency event. AEMO stated in the final operating incident report:[655]

> AEMO has identified two key factors that increased the reliance on load interruption to rebalance power system demand with supply on 25 August 2018:
>
> - Limited or no primary frequency control response from many generators - noting there is no regulatory obligation and no commercial incentive to provide frequency control other than through existing FCAS markets.
> - The distribution of FCAS reserves across the NEM at the time of the event - the allocation of contingency and regulation FCAS reserves does not usually include any need for geographic distribution. In this event there were significant differences between the needs of the power system, and the distribution of frequency response enabled via FCAS markets.

The operating incident report includes eight recommendations intended to improve the resilience of the power system to contingency events in excess of the largest credible contingency event.

AEMO's principal recommendation in the final incident report is the implementation of interim actions, through rule changes as required, to deliver sufficient primary frequency control in the NEM. This recommendation is consistent with the actions set out in the frequency control work plan published as part of the final report for the AEMC's *Frequency control frameworks review* in July 2018. AEMO has proposed to work with the AEMC, AER and generators to finalise suitable interim measures by Q3 2019. AEMO will also support work on a permanent mechanism to secure adequate primary frequency control, with the aim of identifying any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.

AEMO's recommendations are outlined in Table 5.4.

Table 5.4: AEMO recommendations

RECOMMENDATION	TIMELINE
AEMO to investigate the opportunity for automation of reconfiguring AEMO's systems including AGC and NEMDE after separation and large system events.	AEMO to report on options to industry in Q2 2019.
AEMO to investigate whether a minimum regional FCAS requirement is feasible, or whether there may be scope to	After interim primary frequency control

654 AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018,* January 2019, p. 7.
655 Ibid, p. 6-7.

RECOMMENDATION	TIMELINE
manage frequency requirements arising from non-credible regional separation under the protected events framework in the NER.	outcomes at the end of Q3 2019.
AEMO to work with participants to obtain information required to fully and accurately model generator frequency response and all other active power controls.	Commencing in Q1 2019.
Distributed PV – AEMO to work with industry and Standards Australia to: 1. immediately assess technical requirements of inverters (AS 4777) 2. work with stakeholders to implement improved performance standards for inverters 3. establish solutions for obtaining data on the performance of distributed rooftop PV systems, and to develop the necessary simulation models and analysis tools to predict their response to system disturbances.	1. Complete by Q2 2019. 2. By end of 2019. 3. Progressively up to the end of 2020.
1. AEMO to immediately commence a review of the Emergency APD Portland Tripping scheme to identify improvements. 2. AEMO to also review other existing AC interconnector schemes with TNSPs, to determine whether their performance remains fit for purpose in the changing environment and are properly co-ordinated	1. By 1 July 2019. 2. By Q1 2020.
AEMO to continue implementation and investigate any further functional requirements of Emergency Frequency Control Schemes for each region.	Commencing with South Australia and Queensland prior Q1 2020.
AEMO to work with market participants to ensure it is advised of any settings that may result in disconnection that are not currently reflected in their generator models, and review adequacy of existing models.	From Q1 2019.

Source: AEMO, *Final report - Queensland and South Australia system separation on 25 August 2018*, January 2019.

5.3 Related work

The Panel notes that various projects were completed in 2017/18 and are currently underway that relate to the security of the power system. A summary of these projects is provided below.

5.3.1 Managing power system fault levels rule

On 19 September 2017, the AEMC published a final rule to place an obligation on TNSPs to maintain minimum levels of system strength.[656] The rule commenced 1 July 2018.

The framework in the final rule clearly allocates responsibility for system strength to the party who is best placed to manage the risks associated with fulfilling that responsibility – that is, the relevant TNSP. The framework enables TNSPs to identify efficient, the least cost solutions that support long run efficient operation, use and investment in electricity services.

The final rule provides for a holistic and technologically neutral solution to issues arising from reduced system strength by requiring TNSPs to maintain system strength at the levels determined by AEMO, under a range of operating conditions specified by AEMO.[657]

TNSPs have a holistic perspective of their network and are able to address system strength in a manner that considers the best options for the entire network, including being able to optimise between sources that can provide system strength services as well as other key services such as inertia. The AEMC expects this to result in more efficient outcomes for consumers in the long term by minimising the potential duplication of investment.

The final rule also places an obligation on new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system. When a new generator is negotiating its connection with the relevant NSP, a system strength impact assessment will be required to be undertaken by the NSP to assess the impact of the connection of the generating system on the ability of the power system to maintain stability in accordance with the NER, and for other generating systems to maintain stable operation including following any credible contingency event or protected event.

5.3.2 Managing the rate of change of power system frequency rule

On 19 September 2017, the AEMC published a final rule to place an obligation on TNSPs to procure minimum required levels of inertia or alternative frequency control services to meet these minimum levels.[658] The rule commenced 1 July 2018.

The AEMC considers that a secure power system demands the availability of minimum levels of inertia at all times and that an obligation on TNSPs to provide this service at the least cost possible. This will provide confidence that system security can be maintained in all regions of the NEM while minimising the cost to consumers.

The Commission has identified the following reasons for placing this obligation on TNSPs:

- The requirement for TNSPs to identify the least cost option or combination of options to provide minimum levels of inertia, together with the existing economic regulatory framework for TNSPs, will provide discipline on the level of expenditure on inertia network services by enabling the AER to assess the efficiency of that expenditure.

656 For more information, see: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

657 Consistent with this rule requirement, AEMO published *System strength impact assessment guidelines* on 1 July 2018.

658 For more information, see: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

- Placing the obligation on TNSPs to provide inertia network services will provide a greater ability to coordinate the provision of inertia network services with other network support requirements for the relevant sub-network, such as system strength. This should result in a more efficient outcome for consumers in the long term by avoiding the potential duplication of investment.

5.3.3 Generating system model guidelines

On 19 September 2017, the AEMC made a final rule that clarifies the scope and level of detail of model data that registered participants and connection applicants are required to submit to AEMO and network service providers.[659] By allowing AEMO and network service providers to access accurate model data, the final rule supports parties in fulfilling their obligations for maintaining system strength.

The final rule amended the rules frameworks related to the provision of model data to:

- clarify the range of parties who are required to provide model data to AEMO and network service providers
- clarify when this model data must be provided to AEMO and network service providers, including for the purposes of meeting system security obligations
- require AEMO to consider specific principles when developing the power system model guidelines.

The rule commenced 1 July 2018.

5.3.4 Reliability Panel review of frequency operating standards

Under the NER, AEMO must keep the power system stable and securely operating at a frequency close to 50 hertz. The specific frequency requirements that AEMO must meet under different power system conditions are set out in the frequency operating standard (FOS), which is determined by the Panel. The review is investigating the appropriateness of the settings in the standard, in light of the ongoing energy market transformation as conventional synchronous generation leaves the market and asynchronous generation such as wind and solar panels enters the market.[660]

The Panel's FOS review has been undertaken in two stages to accommodate interactions with related work programs. The Panel is now undertaking stage two of the review.

Stage one of the review was completed in November 2017. This first stage addressed primarily technical issues and market framework changes, including the new category of protected contingency event in the FOS. At the conclusion of stage one, the Panel made a new version of the FOS, effective 14 November 2017. The changes made in this new version of the FOS included:

- implementation of changes already made to the NER, through the Emergency frequency control schemes rule.

659 For more information, see: http://www.aemc.gov.au/Rule-Changes/Generating-System-Model-Guidelines#

660 For more information, see: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard

- clarification and further guidance as to how AEMO operates the power system, particularly as this relates to managing different kinds of contingency events.

Stage two of the review commenced on 26 July 2018. The Panel's intent for stage two of the FOS review is to assess and resolve remaining issues identified in stage one of the review. On 6 December 2018, the Panel published a draft determination and a draft FOS which address a number of issues that were identified through stage one of this review. The draft FOS included changes in relation to:

- the limit on the size of the largest generation event in the Tasmanian power system
- improvements to the structure and consistency of the FOS.

The draft determination also included a summary of the Panel's considerations on:

- the settings in the FOS that relate to contingency events
- the limit in the FOS on accumulated time error.

On the advice of AEMO, the Panel has maintained the existing settings in the FOS in relation to these issues, noting that the immediate priority is the joint AEMC-AEMO frequency control work plan published as part of the final report for the *Frequency control frameworks review*.

5.3.5 Inertia ancillary service market rule

On 6 February 2018, the AEMC published a final rule determination not to make a rule on the *Inertia ancillary service market* rule change request submitted by AGL.[661]

The Commission supports the development of competitive markets for the provision of system services for achieving the most efficient outcomes for consumers. However, given the current power system operating conditions, the need to understand practical outcomes from new regulatory frameworks recently introduced, and to also assess outcomes from various programs of work that were underway by the Commission and AEMO, the Commission was not satisfied that the introduction of a market mechanism for inertia was appropriate at the time.

5.3.6 Frequency control frameworks review

On 26 July 2018, the AEMC published a final report on the Frequency control frameworks review.[662]

The report highlights several issues with the existing market and regulatory arrangements for frequency control, and makes recommendations on how they could be addressed. Specifically, the recommendations seek to:

- address the recent deterioration of frequency performance under normal operating conditions
- promote transparency of NEM frequency control performance and the competitiveness of the frequency control ancillary service markets

661 For more information, see: http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market
662 For more information, see: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

- remove inefficient barriers to the provision of essential frequency control services by new technologies.

The major deliverable of the final report is a work plan, developed collaboratively by the AEMC, AEMO and the AER, detailing actions to be taken by the market bodies, in consultation with stakeholders, to address the identified issues and to progress the recommendations referred to above.

5.3.7 Register of distributed energy resources rule

On 13 September 2018, the AEMC made a final rule for AEMO to establish a register of distributed energy resources in the NEM, including small scale battery storage systems and rooftop solar.[663] The register will give network businesses and AEMO visibility of where distributed energy resources are connected to help in planning and operating the power system as it transforms.

The final rule amends the NER to establish a process by which AEMO, network service providers and other interested stakeholders may obtain static data on distributed energy resources across the NEM. The final rule:

- places an obligation on AEMO to establish, maintain and update a register of static data for DER devices in the NEM
- requires network service providers to request from their customers the specific DER generation information outlined by AEMO in guidelines (through the network connection process and deemed standard connection contract) and provide this to AEMO
- introduces a data sharing framework that obliges AEMO to share disaggregated data regarding the locational and technical characteristics of devices in the DER register with network businesses in relation to their network areas (including data that was not reported through their connection processes or contracts), subject to privacy laws and protected information provisions in the NEL
- places an obligation on AEMO to periodically report publicly relevant information from the DER register at an appropriate level of aggregation
- allows AEMO to provide DER register information to an emergency services agency if requested for the purposes of that agency's response to an emergency or for planning in relation to emergency responses.

The new register must be in place by 1 December 2019. The transitional provisions, which commenced on 18 September 2018, include an obligation on AEMO to make and publish the first DER register information guidelines by 1 June 2019.

5.3.8 Generator technical performance standards rule

On 27 September 2018, the AEMC published a rule determination on technical performance standards for generators seeking to connect to the national electricity grid, and the process for negotiating those standards.[664]

663 For more information, see: https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources

664 For more information, see: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

The rule improves and clarifies the negotiating process to agree levels of technical performance when connecting generators, customers and market network service providers. Under the rule, negotiations can occur more efficiently so that each connection has a level of performance that balances system security and cost based on the needs of the local system.

The rule also changes the technical requirements for connecting generators, including the requirements for generating systems to be able to:

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

The new technical performance standards came into effect as of 1 February 2019.

5.3.9 Projects underway

There are a number of system security related projects that the AEMC is currently working on together with the other market bodies, and which shortly will be initiated for public consultation. They include:[665]

- The AEMC's investigation into *Intervention mechanisms and system strength* in the NEM will consider the effectiveness of the intervention framework in light of the increasing use of directions by AEMO to manage system security, and how related system strength frameworks could be improved to avoid the need for directions.
- The AEMC's *Frequency control interim arrangements* project, which will focus on short term changes to manage frequency deterioration in the NEM, including encouraging generators to provide frequency control responses where feasible.
- The AEMC's *Frequency control work plan*, which will focus on designing new, coordinated and lowest-cost ways to deliver frequency control services over the medium to longer term.
- The AEMC will also consider the concept of system resilience, through the work it has underway, now that the AEMO and AER investigations into 28 September 2016 South Australian Black System event are largely complete.

665 For more information, see: https://www.aemc.gov.au/sites/default/files/2019-02/System%20security%20and%20reliability%20action%20plan.pdf

6 SAFETY REVIEW

This chapter presents the Panel's review of the power system from a safety perspective for 2017/18.

As outlined in chapter 2, the scope of the Panel's consideration of performance for this review primarily relates to generation and the bulk transmission system of the NEM, as it was requested by the AEMC in the terms of reference. The Panel's assessment of the safety of the NEM is therefore limited to consideration of the links between the security of the power system and maintaining the system within relevant standards and technical limits. In the technical safety sense, safety of the national electricity system can be understood to mean that the transmission and distribution systems, and the generation and other facilities connected to them are safe from damage.

Generally, jurisdictions have specific provisions that explicitly refer to safety duties of transmission and distribution systems. The Panel has included a summary of safety outcomes in each NEM jurisdiction by reference to jurisdictional safety requirements. This summary is included in appendix I.

As part of the Panel's assessment of the safety of the power system, this section analyses the responses to operating incidents which have occurred within the NEM during 2017/18. As operating incidents have implications for the overall safety of the system, the response to these incidents is a key indicator of safety performance.

Following a review of AEMO's power system incident reports and consultation with AEMO, the Panel is not aware of any incidents where AEMO's management of power system security has resulted in a safety issue with respect to maintaining the system within relevant standards and technical limits.

There may be instances where AEMO issues a direction and the directed participant may not comply on the grounds that complying with the direction would be a hazard to public safety, or materially risk damaging equipment or contravene any other law.[666] The Panel notes that there were no instances in 2017/18 where this occurred.

666 Directions issued to maintain the power system in a secure operating state are discussed in chapter 5.

A GENERATION CAPACITY CHANGES

This appendix summarises changes in generation capacity in the NEM during 2017/18. Generally, the changes included:

- an increase in renewable sources of generation, namely more wind farms and large-scale solar
- announced withdrawals of synchronous generation from Queensland, New South Wales and South Australia.

A.1 Increases in NEM capacity

Table A.1 provides a granular analysis of the generation capacity committed and commissioned between 19 May 2017 and 1 July 2018.[667] Almost all generation commissioned or committed comes from renewable resources.[668] During the reported period 1,178 GW of generation was commissioned and 5,538 GW of generation was committed across Queensland, New South Wales, South Australia and Tasmania.

Table A.1: **New generation commissioned and committed as at 1 July 2018**

REGION	STATUS (AS AT 1 JULY 2018)	POWER STATION	CAPACITY (MW)	FUEL SOURCE
Queensland	Commissioned	Clare Solar Farm	150	Solar
	Commissioned	Dunblane Solar Farm	7.2	Solar
	Commissioned	Kidstone Solar Project	50	Solar
	Commissioned	Lake Somerset	4.3	Water
	Commissioned	Lakeland Solar and Storage Project	12.5	Solar
	Commissioned	Longreach Solar Farm	15	Solar
	Commissioned	Sun Metals Solar Farm	125	Solar
	Commissioned	Sunshine Coast Solar Farm	15	Solar
	Committed	Tableland Mill	24	Biomass
	Committed	Childers Solar Farm	56	Solar
	Committed	Clermont Solar Farm	92.5	Solar
	Committed	Collinsville PV	42.5	Solar

667 The analysis provided is not strictly aligned with the 2017/18 financial year. This is because data is based on the AEMO's regional generation information pages that were published as at 19 May 2017, 22 December 2017, 16 March 2018 and 1 July 2018.

668 Hunter Economic Zone diesel generator (28.8 MW) in New South Wales was the only non-renewable generator commissioned in this period. Barker Inlet Power Station (210 MW) in South Australia was the only non-renewable generator committed during the reported period.

REGION	STATUS (AS AT 1 JULY 2018)	POWER STATION	CAPACITY (MW)	FUEL SOURCE
	Committed	Darling Downs Solar Farm	108.5	Solar
	Committed	Daydream Solar Farm	167.5	Solar
	Committed	Emerald Solar Park	72	Solar
	Committed	Haughton Solar Farm	100	Solar
	Committed	Hayman Solar Farm	50	Solar
	Committed	Kennedy Energy Park - Phase 1	15	Solar
	Committed	Lilyvale Solar Farm	100	Solar
	Committed	Oakey 1 Solar Farm	25	Solar
	Committed	Oakey 2 Solar Farm	55	Solar
	Committed	Ross River Solar Farm	128	Solar
	Committed	Rugby Run Solar Farm	65	Solar
	Committed	Susan River Solar Farm	75	Solar
	Committed	Yarranlea Solar	102.5	Solar
	Committed	TeeBar Solar Farm	52.5	Solar
	Committed	Kennedy Energy Park - Phase 1	2	Storage
	Committed	Coopers Gap Wind Farm	350	Wind
	Committed	Kennedy Energy Park - Phase 1	43.2	Wind
	Committed	Mt Emerald Wind Farm	180.5	Wind
	Committed	Hamilton Solar Farm	57.5	Solar
	Committed	Whitsunday	57.5	Solar
New South Wales	Commissioned	Silverton Wind Farm	198.94	Wind
	Commissioned	White Rock Solar Farm	20	Solar
	Commissioned	Sapphire Wind Farm Phase 1 and 2	270	Wind
	Committed	Crookwell 2 Wind Farm	91	Wind
	Committed	Beryl Solar Farm	98.4	Solar

REGION	STATUS (AS AT 1 JULY 2018)	POWER STATION	CAPACITY (MW)	FUEL SOURCE
	Committed	Coleambally Solar Farm	180	Solar
	Committed	Crudine Ridge Wind Farm	135	Wind
	Committed	Bodangora Wind Farm	113	Wind
Victoria	Committed	Bannerton Solar Park	88	Solar
	Committed	Crowlands Wind Farm	79.95	Wind
	Commissioned	Kiata Wind Farm	31.05	Wind
	Committed	Mt Gellibrand Wind Farm	132	Wind
	Committed	Ballarat Energy Storage System	30	Storage
	Commissioned	Swan Hill Solar Farm	15	Solar
	Committed	Yatpool Solar Farm	81	Solar
	Commissioned	Salt Creek Wind Farm	54	Wind
	Committed	Bulgana Green Power Hub - Wind Farm	204	Wind
	Committed	Bulgana Green Power Hub - BESS	20	Storage
	Committed	Gannawarra Energy Storage System	25	Storage
	Committed	Gannawarra Solar Farm	50	Solar
	Committed	Karadoc Solar Farm	90	Solar
	Committed	Lal Wind Energy Facility - Elaine end	79	Wind
	Committed	Moorabool Wind Farm	320	Wind
	Committed	Murra Warra Wind Farm - stage 1	225.5	Wind
	Committed	Stockyard Hill	532	Solar
	Committed	Wemen Solar Farm	87.75	Solar
South Australia	Commissioned	Hornsdale Wind Farm Stage 2	102	Wind
	Commissioned	Hornsdale Wind Farm Stage 3	109	Wind

REGION	STATUS (AS AT 1 JULY 2018)	POWER STATION	CAPACITY (MW)	FUEL SOURCE
	Commissioned	Hornsdale Power Reserve	100	Storage
	Committed	Lincoln Gap Wind Farm Stage 1	126	Wind
	Committed	Willogoleche Wind Farm	125	Wind
	Committed	Dalrymple Battery storage	30	Storage
	Committed	Barker Inlet Power Station	210	Gas
	Committed	Tailem Bend - Solar	108	Solar
Tasmania	Committed	Granville Harbour Wind Farm	111.6	Wind
	Committed	Wild Cattle Hill Wind Farm	144	Wind
Total commissioned			**1,178**	
Total committed			**5,538**	

Source: AEMO, *Generator Information page*, 29 December 2017, 16 March 2018 and 31 July 2018.

A.2 Withdrawn generation

In 2017/18, Tamar Valley combined-cycle gas turbine in Tasmania was the only generator withdrawn. Table A.2 lists the withdrawn generation and generation that has announced the intention to withdraw.

Table A.2: **Generator withdrawals**

REGION	STATUS (AT THE END OF 2017/18)	POWER STATION	CAPACITY (MW)	FUEL SOURCE
Queensland	To be withdrawn in 2021	Mackay GT Power Station	34	Gas
New South Wales	To be withdrawn in 2022	Liddell Power Station	1800	Black coal
Victoria	No generation withdrawn or announced for withdrawal in 2017/18.			
South Australia	To be withdrawn with two units withdrawing in	Torrens A Power Station	480	Gas

REGION	STATUS (AT THE END OF 2017/18)	POWER STATION	CAPACITY (MW)	FUEL SOURCE
	2019, and the other two in 2020 and 2021			
Tasmania	Withdrawn	Tamar Valley CCGT	208	Gas

Source: AEMO, *Generator Information page*, 31 July 2018.
Note: Tamar Valley CCGT was returned to service for summer 2017/18 and withdrawn again in April 2018.

Table A.3 shows whether recently withdrawn generation is able to be recalled.

Table A.3: Ability for withdrawn generation to be recalled

REGION	POWER STATION	CAPACITY (MW)	ABILITY TO BE RECALLED
Queensland	Swanbank E GT	385	Yes - after being in cold storage, Swanbank E GT returned to service on 1 December 2018.
	Pelican Point Power Station	adding 240 MW	The plant reduced capacity by half in April 2015, and returned to full capacity (adding 240 MW) from July 2017.
New South Wales	Smithfield Energy Facility	170.9	Yes - initially closed in July 2017, has been brought back into service with up to 109 MW of capacity available, with a further 62 MW available on recall.
Tasmania	Tamar Valley CCGT	208	Yes - available for operation with less than three months notice.

Source: AEMO, *Generator Information page*, 31 July 2018.

B NETWORK PERFORMANCE

This appendix provides a summary of transmission network and distribution network performance in 2017/18.

Network outages result in lost load which is not counted towards unserved energy. This is because unserved energy is only demand not met due to insufficient generation and bulk transfer, which does not include interruptions to supply caused by disturbances on intra-regional transmission and distribution networks.

Outages on the transmission network are measured in system unsupplied minutes which is the amount of energy not supplied, divided by maximum demand, multiplied by 60.

Outages on the distribution network are typically measured by both the aggregate time in which an outage occurred, SAIDI, and the frequency of outages, SAIFI.

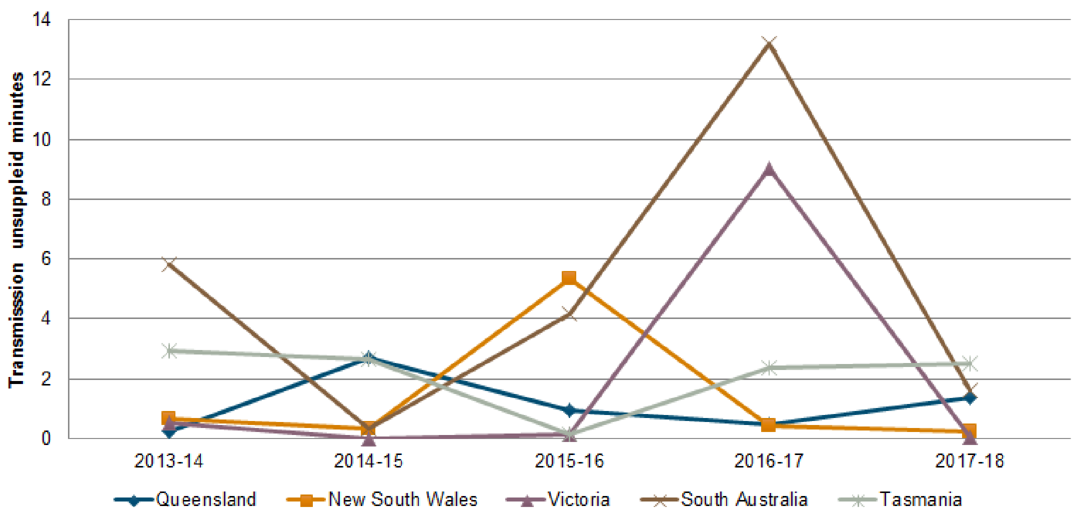
B.1 Transmission network

The number of system minutes not supplied due to transmission outages provides an aggregate indicator of the performance of transmission networks.

B.1.1 National

Figure B.1 shows the performance of the transmission networks as experienced by consumers in each region.

Figure B.1: Transmission unsupplied minutes



Source: Queensland - Powerlink; New South Wales - TransGrid; Victoria - AusNet Services; South Australia - ElectraNet; Tasmania - TasNetworks.

Note: The calculated value of unsupplied minutes is the amount of energy not supplied, divided by maximum demand, multiplied by 60.

Note: For South Australia, the 28 September 2016 black system event did not contribute to unsupplied minutes calculations due to supply/demand imbalance and force majeure.

In 2017/18, Victoria and South Australia experienced decreased levels of transmission unsupplied minutes after a significant increase in 2016/17. In New South Wales, transmission unsupplied minutes also decreased. Queensland and Tasmania experienced a slight increase in transmission unsupplied minutes from 2016/17 levels.

There are some national requirements that impact upon the reliability of the transmission network. Part B of chapter 5 of the rules includes planning requirements for transmission networks. TNSPs are required to carry out an annual planning review which must be reported in an annual market performance report. In addition, they must undertake a regulatory investment test for transmission where the estimated capital cost of the most expensive potential credible option to address an identified need is more than $6 million.

Schedule 5.1 of the rules describes the planning, design and operating criteria that must be applied by TNSPs. It also describes the requirements on TNSPs to institute consistent processes to determine the appropriate technical requirements to apply for each connection enquiry or application to connect processed by the TNSP. The objective is that all connections satisfy the requirements of this schedule.

In addition, TNSPs are subject to the AER's service target performance incentive scheme which provides financial incentives to maintain and improve performance, including reliability.[669]

The next sections provide a summary of jurisdictional arrangements that impact upon the reliability of the transmission network.

B.1.2 Queensland

For Queensland, in addition to the requirements in the rules above, mandated reliability obligations and standards are contained in the Electricity Act 1994 (Queensland) and in Powerlink's Transmission Authority. As the TNSP in Queensland, Powerlink must adhere to these obligations and its connection agreements with other parties.

Powerlink plans future network augmentations in accordance with these requirements (among other things). It does this based on satisfying the following obligations:

- to ensure as far as technically and economically practicable that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid.[670]
- planning and developing its transmission network in accordance with good electricity industry practice such that the power transfer available through the power system will be such that the forecast of electricity that is not able to be supplied during the most critical single network element outage will not exceed either 50MW at any one time; or 600MWh in aggregate.[671]

669 The service target performance incentive scheme is developed and published by the AER in accordance with clause 6A.7.4 of the rules.

670 Section 34(2) of the *Electricity Act 1994 (Queensland)*.

671 Transmission Authority No. T01/98.

B.1.3 New South Wales

In accordance with the Transmission Operator's Licence issued by the New South Wales Government on 7 December 2015, TransGrid must plan and develop its transmission network to meet the NSW Electricity Transmission Reliability Standards that came into effect on 1 July 2018.

In general terms, the standards comprise two components for each bulk supply point (BSP):

- A required level of network redundancy for each BSP or group of BSPs that function as a cohort, appropriate to the size and the significance of the load being supplied; and
- The maximum amount of time the average load on the BSP (or BSP group) that may be at risk of not being supplied.

TransGrid outlines its plans to meet its obligations with the standards in the Transmission Annual Planning Report that it publishes by 30 June each year.

B.1.4 Victoria

Victoria is the only jurisdiction where AEMO has declared network functions. In Victoria, the functions undertaken by TNSPs elsewhere are split between AEMO and Declared Transmission System Operators (DTSOs). AEMO is accountable for the provision of the shared network, procuring services from DTSOs (such as AusNet Services), who own and operate the shared assets.

Under the NEL, jurisdictions can declare AEMO to have declared network functions. AEMO's declared network functions include:

- to plan, authorise, contract for, and direct augmentation of the declared shared network[672]
- to provide information about the planning process for augmentation of the declared shared network
- to provide information and other services to facilitate decisions for investment and the use of resources in the adoptive jurisdiction's electricity industry
- to provide shared transmission services by means of, or in connection with, the declared shared network
- any other functions, related to the declared transmission system or electricity network services provided by means of or in connection with the declared transmission, conferred on it under the NEL or the NER
- any other functions, related to the declared transmission system or electricity network services provided by means of or in connection with the declared transmission system, conferred on it under a law of the adoptive jurisdiction.

672 In Victoria, where AEMO assesses that network or non-network development is needed, augmentation projects may be competitively tendered.

B.1.5 Tasmania

TasNetworks is the TNSP in Tasmania. It is obliged to meet the requirements of its transmission licence, *Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas)*, and the terms of its connection agreements.

The objective of the *Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas)* is to specify the minimum network performance requirements that a planned power system of a TNSP must meet. TasNetworks is required by the terms of its licence to plan and procure all transmission augmentations to meet these network performance requirements. TasNetworks publishes an Annual Planning Report, which includes discussion of any forecast supply shortfalls against the *Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas)*, and proposed remedial actions.

The *Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (Tas)* sets out:

- minimum network performance requirements in respect of electricity transmission services in Tasmania
- the process for exemptions in respect of such requirements
- provisions in respect of Ministerial approval of certain augmentation in respect of such services.

B.1.6 South Australia

As the TNSP in South Australia, ElectraNet is subject to the Electricity Transmission Code administered by the Essential Services Commission of South Australia (ESCOSA). The Code sets specific reliability standards which are determined economically and expressed on a deterministic basis (for example, N, N–1, and N–2) for each transmission exit point.

ESCOSA reviewed the Code in 2016 and set the transmission network planning and reliability standards to apply from 1 July 2018, the start of the next five-year regulatory period for ElectraNet.[673] In April 2018, ESCOSA initiated another targeted review of the Code. The review has been undertaken to clarify existing provisions of the Code and make consequential changes to reflect legislative amendments. In August 2018, ESCOSA published the final decision aimed to address, among other things, the following issues:

- Clarification of the expression of the reliability standards that apply to transmission exit points where there are two supply sources and the back-up source is non-firm.
- Application of reliability standards to customers that receive negotiated transmission services, such as grid-scale batteries.[674]

673 ESCOSA, *Electricity Transmission Code review: Final decision*, September 2016.
674 ESCOSA, *2018 review of the Electricity Transmission Code: Final decision*, August 2018.

B.2 Distribution network

All jurisdictions have their own monitoring and reporting frameworks for reliability of distribution network service providers (DNSPs). There are two main indicators of distribution network reliability:

- system average interruption frequency index (SAIFI)
- system average interruption duration index (SAIDI).

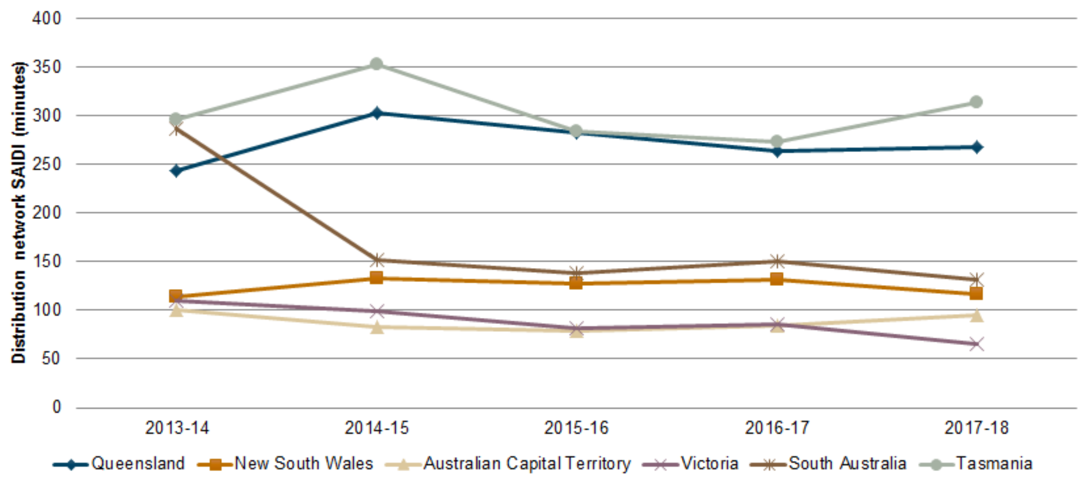
B.2.1 National

The performance of distribution networks, and the reliability standards that must be met, fall within the responsibility of jurisdictions.

These reliability standards are often measured in terms of the SAIDI. SAIDI is defined as the sum of the duration of each sustained customer interruption, divided by the number of customers. It is calculated for different parts of each DNSP's network. Unplanned SAIDI relates to unplanned outages. These unplanned outages are typically caused by operational error or damage caused by extreme weather and damage by trees. The average SAIDI figure for each NEM jurisdiction over the past five years is shown in Figure B.2.

The Panel notes different exclusion methodologies, variances in customer numbers by feeder and different geographical conditions may apply in each jurisdiction. These averages are therefore to represent a summary only. Additionally, the average SAIDI provided is calculated on a different basis and therefore, averages should not be directly compared between jurisdictions.

Figure B.2: Distribution network SAIDIs



Source: Queensland - Queensland Department of Natural Resources, Mines and Energy; New South Wales - Independent Pricing and Regulatory Tribunal; ACT - ActewAGL; Victoria - Australian Energy Regulator; South Australia - Essential Services Commission of South Australia; Tasmania - TasNetworks.

In 2017/18, all jurisdictions experienced flat or declining levels of distribution outages, except the Australian Capital Territory and Tasmania. Each jurisdiction's performance is explored in more detail below.

B.2.2 Queensland

The Queensland Electricity Act 1994 and the Electricity Regulation 2006 define the arrangements for the Queensland DNSPs (Ergon Energy and Energex, which in 2016 merged to form Energy Queensland).

Performance standards for Queensland DNSPs were introduced in 2005/06. The current service level reliability limits for SAIDI and SAIFI are regularly reviewed and have been set to apply to 2019/20.

Minimum service standards (reliability limit targets) for the 2017/18 financial year are outlined in Schedule 2 of the distribution authority issued to Energex and Schedule 3 of the distribution authority issued to Ergon Energy.

The Electricity Distribution Network Code sets guaranteed service levels and payments that must be met by Energy Queensland, who report quarterly to the QCA on their guaranteed service levels performance relative to their targets. The QCA then reports this information to the Department of Natural Resources, Mines and Energy, and the standards are published on its Business Queensland website.

Table B.1 details the performance of Energex and Ergon Energy against the minimum service standards set for 2017/18. It shows that Energex and Ergon met all of their SAIDI and SAIFI targets for the different feeder categories during 2017/18.

Table B.1: Performance of Queensland DNSPs in 2017/18

DNSP	FEEDER LEVEL	SAIDI		SAIFI	
		TARGET	AVERAGE	TARGET	AVERAGE
Energex	CBD	15	4.8	0.15	0.03
	Urban	106	73.09	1.26	0.67
	Short Rural	218	187.38	2.46	1.46
Ergon	Urban	149	134	1.98	1.52
	Short Rural	424	315.54	3.95	2.70
	Long Rural	964	891.29	7.40	5.55
Average	-	-	267.68	-	-

Source: Queensland Department of Natural Resources, Mines and Energy.

B.2.3 New South Wales

The *Electricity Supply Act 1995* requires the New South Wales DNSPs to be licenced unless an exemption applies. Network performance standards for the licensed New South Wales DNSPs have been set by the Minister for Energy and are included as licence conditions.[675]

The performance of the licensed New South Wales DNSPs against the performance standards is monitored by Independent Pricing and Regulatory Tribunal (IPART) by various means including:

- quarterly performance reporting against the licence conditions
- incident reports
- annual compliance audits
- consumer complaints, including to the New South Wales Energy and Water Ombudsman
- media reports.

IPART also produces an annual licence compliance report for the Minister, which from 2007 includes compliance with the reliability standards. This report must be tabled in Parliament, after which it is published on IPART's website.

Table B.2 shows a summary of the New South Wales DNSPs' overall performance and by feeder classification. All New South Wales DNSPs met their respective SAIDI and SAIFI targets in 2017/18.[676]

Table B.2: **Performance of New South Wales DNSPs in 2017/18**

DNSP	FEEDER LEVEL	SAIDI		SAIFI	
		TARGET	ACTUAL	TARGET	ACTUAL
Essential Energy	Urban	125	89	1.8	1.14
	Short-rural	300	206	3.0	1.81
	Long-rural	700	439	4.5	2.71
	All	n/a	212	n/a	1.78
Ausgrid	CBD	45	13	0.3	0.06
	Urban	80	64	1.2	0.65
	Short-rural	300	114	3.2	0.98
	Long-rural	700	354	6.0	1.60
	All	n/a	69	n/a	0.68
Endeavour Energy	Urban	80	49	1.2	0.59
	Short-rural	300	126	2.8	1.28
	Long-rural	n/a	493	n/a	3.4

675 These conditions were set in 2007 and are published on IPART's website, https://www.ipart.nsw.gov.au/Home/Industries/Energy/Energy-Networks-Safety-Reliability-and-Compliance/Electricity-networks

676 More detailed performance information is available from network performance reports published on each of the DNSPs websites.

DNSP	FEEDER LEVEL	SAIDI		SAIFI	
		TARGET	ACTUAL	TARGET	ACTUAL
	All	n/a	71	n/a	0.78
Average	-	-	117.33	-	-

Source: IPART.

B.2.4 Australian Capital Territory

Technical codes in the ACT, including the Electricity Distribution Supply Standards Code, are determined by the Minister for the Environment under the *Utilities (Technical Regulation) Act 2014*.

Table B.3 shows a summary of the performance of ActewAGL Distribution, the DNSP in the Australian Capital Territory, against the performance targets pertaining to feeder classification in 2017/18. It shows that ActewAGL met all its SAIFI and SAIDI targets except for SAIDI target for urban feeder.

Table B.3: **Performance of ActewAGL for 2017/18**

FEEDER LEVEL		SAIDI		SAIFI		CAIDI	
		TARGET	ACTUAL	TARGET	ACTUAL	TARGET	ACTUAL
Urban	Overall	n/a	99.64	n/a	1.42	n/a	70.17
	Distribution network - planned	n/a	61.92	n/a	0.23	n/a	269.22
	Distribution network - unplanned	n/a	37.72	n/a	1.18	n/a	31.97
	Normalised distribution network - unplanned	30.32	31.76	0.585	0.48	n/a	66.17
Rural short	Overall	n/a	60.71	n/a	1.92	n/a	31.62
	Distribution network - planned	n/a	21.98	n/a	0.13	n/a	169.08

FEEDER LEVEL		SAIDI		SAIFI		CAIDI	
		TARGET	ACTUAL	TARGET	ACTUAL	TARGET	ACTUAL
	Distribution network - unplanned	n/a	38.72	n/a	1.79	n/a	21.63
	Normalised distribution network - unplanned	46.86	29.10	0.895	0.58	n/a	50.17
Network	Overall	n/a	95.03	n/a	1.48	n/a	64.21
	Distribution network - planned	n/a	57.18	n/a	0.22	n/a	259.91
	Distribution network - unplanned	n/a	37.84	n/a	1.26	n/a	30.03
	Normalised distribution network - unplanned	32.12	31.44	0.619	0.49	n/a	64.16

Source: ActewAGL Distribution
Note: CAIDI is a customer average interruption duration index.

B.2.5 Victoria

The Electricity Industry Act 2000 and the Essential Services Commission Act 2001 contain the network performance requirements for the Victorian DNSPs.

From 1 January 2009, responsibility for the compliance monitoring and enforcement of the DNSPs' distribution licence conditions was transferred to the AER from the Essential Services Commission of Victoria.

As part of its 2016 distribution regulatory determination, the AER sets SAIDI and SAIFI targets for the Victorian DNSPs for the 2016–2020 regulatory period.[677] These targets are developed for the purpose of applying the AER's service target performance incentive scheme to the DNSPs.[678] Under the service target performance incentive scheme, the AER annually reviews the service performance outcomes and determines the resulting financial penalty or reward based on a DNSPs performance against the targets established at the time of a distribution determination.

Table B.4 shows a summary of the performance of Victorian DNSPs against performance targets for each feeder classification, for 2017/18. All Victorian DNSP met their respective SAIDI and SAIFI targets except AusNet Services for SAIDI targets for urban feeders.

Table B.4: Performance of Victorian DNSPs for 2017/18

DNSP	FEEDER LEVEL	SAIDI		SAIFI	
		TARGET	ACTUAL	TARGET	ACTUAL
Jemena	Urban	55.40	41.45	0.95	0.78
	Short-rural	91.95	57.61	1.24	0.85
	Whole Network	n/a	42.37	n/a	0.79
CitiPower	CBD	9.13	4.71	0.13	0.07
	Urban	32.70	26.34	0.48	0.45
	Whole Network	n/a	22.48	n/a	0.38
Powercor	Urban	83.11	56.14	1.05	0.71
	Short-rural	113.19	99.39	1.36	1.16
	Long-rural	273.09	167.96	2.37	1.67
	Whole Network	n/a	100.09	n/a	1.11
AusNet Services	Urban	80.90	81.23	1.09	0.97
	Short-rural	187.14	124.19	2.28	1.62
	Long-rural	232.74	212.11	2.82	2.50
	Whole Network	n/a	121.28	n/a	1.50
United Energy	Urban	61.19	41.11	0.90	0.60
	Short-rural	151.60	65.37	2.02	1.11

677 The AER released its distribution revenue and service determination for the 2016-20 period in May 2016.

678 Under the *Australian Energy Market Agreement*, setting and enforcement of quality and reliability of supply is a matter of each jurisdiction. In other words, the AER sets targets and provide the financial incentive to meet and exceed the targets. However, their targets are not the minimum standard under a regulation.

DNSP	FEEDER LEVEL	SAIDI		SAIFI	
		TARGET	ACTU-AL	TARGET	ACTU-AL
	Whole Network	n/a	42.84	n/a	0.64
Average			65.8		

Source: AER.

B.2.6 South Australia

The Essential Services Commission of South Australia (ESCOSA) is responsible for setting elements of the service standard framework. For example, ESCOSA is responsible for setting the South Australian jurisdictional service standards applying to SA Power Networks and guaranteed service levels.

ESCOSA has established annual standards for frequency and duration interruptions for the four feeder category types within SA Power Network's distribution network. These are specified by ESCOSA as 'best endeavour' annual targets in the Electricity Distribution Code. SA Power Networks must comply with the service standards set out in Chapter 1 of the Code.

In October 2014, ESCOSA released its final decision on the jurisdictional service standards and Guaranteed Service Level scheme to apply to SA Power Networks for the 2015-2020 regulatory period. The final decision consisted of:

- Network reliability and service standards: to be set for the frequency and duration of unplanned interruptions to reflect the average historical reliability levels at four levels of distribution feeders. These reliability targets had traditionally been set for geographical regions.
- Guaranteed Service Level scheme: the state-based scheme will continue and will include an additional tier for outages greater than 48 hours. The payment levels were adjusted to reflect the change in consumer price index since they were first set.[679]

Table B.5 shows a summary of the performance of SA Power Networks for 2017/18 against the performance targets pertaining to each feeder classification. SA Power Networks met almost all of its performance targets in 2017/18 except for SAIDI and SAIFI targets for CBD feeders.

679 The Guaranteed Service Level scheme relates to the experience of individual customers. Payments are automatically made to customers who receive service that does not meet threshold levels. The relevant services include timeliness of appointments and frequency and duration of supply interruption. More information on the scheme is available at: https://www.escosa.sa.gov.au/ArticleDocuments/281/20170323-Electricity-SAPN-GSL-Factsheet.pdf.aspx?Embed=Y

Table B.5: **Performance of SA Power Networks for 2017/18**

FEEDER LEVEL	SAIDI		SAIFI	
	TARGET	ACTUAL	TARGET	ACTUAL
CBD	15	42.6	0.15	0.40
Urban	120	96.1	1.30	1.06
Short-rural	220	155.1	1.85	1.20
Long-rural	300	269.2	1.95	1.48
Total network	165	131.6	1.50	1.14

Source: ESCOSA.

B.2.7 Tasmania

The network performance requirements for electricity distribution in Tasmania are prescribed in the Tasmanian Electricity Code.

On 1 January 2008, the Office of the Tasmanian Economic Regulator amended the Tasmanian Electricity Code to incorporate new distribution network supply reliability standards, which were developed jointly by the Office of the Tasmanian Energy Regulator, the Tasmanian Office of Energy Planning and Conservation, and TasNetworks (previously Aurora Energy). These are designed to align the reliability standards more closely to the needs of the communities served by the network.

The distribution network supply reliability standards have two parts:

- minimum network performance requirements specified in the Tasmanian Electricity Code for each of five community categories: Critical Infrastructure, High Density Commercial, Urban and Regional Centres, Higher Density Rural and Lower Density Rural
- a guaranteed service level supported by the TEC and relevant guidelines.

Table B.6 shows a summary of the performance of TasNetworks' distribution network for 2017/18, against the performance targets pertaining to each community category. In 2017/18, the critical infrastructure category was the only category where performance was within both the frequency and duration limits. Duration limits were not met for all other community categories. All outage frequency limits were met.

Table B.6: **Performance of TasNetworks (distribution) for 2017/18**

COMMUNITY CATEGORY	SAIDI		SAIFI	
	TARGET	ACTUAL	TARGET	ACTUAL
Critical infrastructure	30	29.6	0.2	0.15

COMMUNITY CATEGORY	SAIDI		SAIFI	
	TARGET	ACTUAL	TARGET	ACTUAL
High density commercial	60	70.1	1	0.37
Urban and regional centres	120	227.3	2	1.48
Higher density rural	480	544.1	4	3.19
Lower density rural	600	700.5	6	3.72

Source: TasNetworks.
Note: These targets are set as 12 month limits in the Tasmanian Electricity Code.

C THE CONTRACT MARKET

This appendix provides a summary of how the contract market operates and how it supports the reliability framework.

Reliable supply in the NEM is supported by the inherent and symmetrical incentive for buyers and sellers to enter into contracts to have more certainty over costs and revenue over time.

For an electricity system to work properly and contribute to reliability, supply must equal demand plus market reserves (near) instantaneously. Because of this need to co-ordinate supply and demand in real time, the mechanisms for buying and selling electricity at the wholesale level are divided into two parts:

- A formal spot market, governed by the NER and operated by AEMO, which co-ordinates the physical operation of the power system.
- A voluntary and informal financial hedge contract market, which provides parties with more certain revenues and costs over the term of their contracts.

All electricity traded in the NEM must be settled through the spot market (known as a gross pool). The variability of demand and supply conditions results in fluctuations in spot prices, which can range from the market price cap to the market floor price. Both buyers and sellers appreciate that large swings in spot prices have a similar but opposite effect on their costs and revenue and, consequently, their profits and share price. This encourages both buyers and sellers to agree to contracts that convert volatile spot revenues and costs for a more certain cash flows or to help underwrite further investment in both generation and retail assets(vertical integration).

While its primary role is to smooth the cash flows of buyers and sellers to manage these risks, the contract market also supports reliability by informing both investment and operational decisions.

Contracts support operational decisions

On a short term operational time scale (e.g. hourly), contracts provide certainty for participants and inform their decisions in the face of risky market conditions. For instance, holding a swap contract incentives generators to be available when needed (i.e. when demand and spot prices are high) in an operational timeframe, in order to earn revenues in the spot market to fund payouts on their contract positions.

Though a generator‛s contract is cash-settled (i.e. it is of a financial, rather than physical, nature), the existence of a contract prompts a physical response from the generator. This incentive to ‛turn up’ is heightened during tight demand-supply conditions, when the value of reliability is signalled by high prices and the system values the generator’s output the most. In this way, contracts create a direct link between the needs of the system for capacity and the financial rewards that accrue to generators from being available and dispatched, and the losses or penalties they incur if they are not.

For example, if a generator sells a firm hedge or cap contract then, when the market signals a need for more supply by the price approaching to the market price cap, the generator would face a high penalty for not supplying to the level of its contract cover.

The contract market supports reliability and investment decisions

In the longer term, the contract market supports reliability in three ways:

- It provides market participants signals of market expectations of future spot prices (a forward price curve). These price signals support decisions to fund new generation projects (or retire existing ones), locate and fund a new energy-intensive industrial factory (or retire an existing one), or demand-side management capability (or retire an existing one).
- It lowers the cost of financing of investment in generation capacity, which lowers the cost of achieving efficient levels of reliability. By providing generators a steadier stream of income compared to taking spot price exposure, contracts reduce the risks to parties providing funding to generators, such as debt and equity holders, that the value of their investments may not be recouped. This lowers the overall cost of capital required to finance the project and lowers the cost of the new generation capacity.
- It underwrites retailers' fixed-price offers to end-consumers, such as households and small businesses. Like generators, retailers use the contract market to mitigate their exposure to the spot market. Contracts provide retailers with a consistent price for electricity, which in turn allows them to offer longer-term contracts, with stable prices, to their retail customers.

D RELIABILITY ASSESSMENT

This appendix provides details on the information sources used to assess reliability in the NEM.

D.1 Reserve projections and demand forecasts

Market information is provided in a number of formats and time frames ranging from long term projections (more than 10 years) that are published annually, through to the detailed five and thirty minute pre-dispatch price and demand projections. The long term information is published across a range of tailored reports, including:

- the *Electricity forecasting insights* (EFI) (which replaced the *National electricity forecasting report*)
- the *Electricity statement of opportunities* (ESOO)
- the *Energy adequacy assessment projection* (EAAP)[680]
- the *Integrated system plan* (ISP)
- the *National transmission network development plan* (NTNDP)
- ongoing market notices.

These documents together inform market participants on the state of the market and its potential evolution over the short and longer terms. This information can assist both existing and intending participants when identifying opportunities in the market. The following sections describe these information sources in more detail.

D.1.1 Electricity forecasting insights

The *EFI* provides forecasts of electricity consumption and maximum and minimum demand forecasts over a 20-year outlook period for the NEM. The *EFI* took the place of AEMO's *National electricity forecasting report* that was published annually in June. AEMO published the first *EFI* in June 2017, which was updated by the *2017 ESOO*. In March 2018, AEMO published *2018 EFI Update,* which in August was updated by the *2018 ESOO*.

In the *EFI,* AEMO presents forecasts that explore a range of scenarios that represent a probable range of futures for Australia across weak, neutral, and strong economic and consumer outlooks.

The Panel notes the following differences between the scenario themes used in the *2018 ESOO* and those used in the March *2018 EFI Update*:[681]

- The new scenarios used the Neutral trajectory for PV for all scenarios (as opposed to higher PV uptake being assumed under strong economic growth conditions, which would lead to less operational demand). Slow change scenario also no longer had slower PV uptake leading to relatively higher operational demand.

680 In 2017, the *Energy adequacy assessment projection* was incorporated into the *Energy supply outlook.* In 2018, the *Energy adequacy assessment projection* was published.

681 AEMO, *2018 Electricity Statement of Opportunities*, August 2018.

- A percentage of behind-the-meter batteries were treated in aggregate in the new scenarios, to allow the examination of batteries operating as virtual power plant (so-called 'smart' batteries) to support system peak demand, rather than individual household benefit.

These changes were intended to increase the spread of possible grid consumption and demand outcomes around the neutral scenario.

D.1.2 Electricity statement of opportunities

The *ESOO* provides technical and market data and information, to the market. It assesses the adequacy of supply to meet demand over a ten-year outlook period, highlighting changes to NEM-wide generation and demand side investment opportunities by analysing the factors which influence these types of investment.

The *ESOO* is an information tool providing information that can help stakeholders plan their operations over a ten-year outlook period, including information about the future supply demand balance.

D.1.3 Energy adequacy assessment projection

The *EAAP* report provides information on the impact of potential energy constraints, such as water storages during drought conditions or constraints on fuel supply for thermal generation, on supply adequacy in the NEM.

Under the *EAAP*'s data collation process, all scheduled generators in the NEM are required to submit information to AEMO regarding the effect of energy supply limitations on their production outputs. This data provides a broad assessment of impacts on supply and reliability in the NEM.

D.2 Planning information

D.2.1 Integrated system plan

AEMO published its inaugural ISP in July 2018. The ISP was developed in response to a recommendation from the *Future Security of the National Electricity Market: Blueprint for the Future* (Finkel Review).[682]

The ISP identifies a pathway for developing the transmission network based on modelling the entire market over possible future scenarios over the next twenty years. The inaugural ISP also identified transmission investments in three groups, in order of priority, that need to be addressed. AEMO identified that there are five group 1 projects that require immediate action; group 2 projects need to be developed in the medium term (mid 2020s) in order to enhance trade between regions, provide access to storage and support extensive development of renewable energy zones; while group 3 projects are longer-term developments to support renewable energy zones, reliability and security.

682 Finkel Panel, *Independent review into the future security of the national electricity market: blueprint for the future*, June 2017,p. 24.

In August 2018, the COAG Energy Council asked that the Chair of the ESB take the lead on the delivery of a work program to "convert the ISP" into an "actionable strategic plan" and report back to the Council's 2018 meeting. In addition, the COAG Energy Council requested the ESB report to the December 2018 meeting on "how the Group 1 projects identified in the ISP can be implemented and delivered as soon as practicable and with efficient outcomes for customers, and how the Group 2 projects will be reviewed and progressed".[683]

The AEMC's *Coordination of generation and transmission investment* final report, in addition to addressing the COAG Energy Council's terms of reference, formed an input into the Chair of the ESB's report.[684] In relation to the ISP actioning, the AEMC's final report provided the detail for how the refinements to the transmission regulatory process recommended by the Chair of the ESB could be implemented, and provided the detail for a path forward on addressing concerns with current access and congestion management arrangements outlined in the Chair of the ESB's report.[685]

D.2.2 National transmission network development plan

In June 2018, AEMO published the first ISP, which met the requirements of a NTNDP and provided a strategic plan for the development of the power system. The 2018 NTNDP, published in December 2018, builds on the ISP, assesses the short term system adequacy of the national transmission grid over the next five years and reports on the implementation of the ISP.

683 COAG Energy Council, *Meeting Communique*, 10 August 2018. See: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/18th%20COAG%20Energy%20Council%20Communique.pdf

684 For more information on the ESB's report, see: ESB, *Integrated system plan; Action plan*, 20 December 2018.

685 For more information, see: AEMC, *Coordination of generation and transmission investment,* final report, 21 December 2018.

E FORECASTS

This appendix considers various market forecasts of demand and generation reported by AEMO in 2017/18.

The Panel recognises the essential role played by energy and demand forecasts in the market, and that these are used by key operational and investment decision makers. Electricity demand and usage forecasts are also important for transparency and to improve awareness in the energy markets.

It is therefore critical that demand forecasts are as accurate as possible. AEMO is required to produce electricity demand and energy forecasts for each NEM region as well as for the NEM as a whole.

Minimum and maximum demand forecasts are discussed in detail in chapter 3 and have not been repeated in this appendix. Outcomes from AEMO's ISP report have been discussed in chapter 3 and appendix C. The key findings from AEMO's ESOO and GSOO publications are described in chapter 4.

E.1 Regional forecast accuracy - operational consumption and maximum demand

AEMO produces the *Forecast Accuracy Report* for its ESOO each year. The *2018 Forecast Accuracy Report* assesses the accuracy of the annual operational consumption, and maximum and minimum operational demand forecasts in AEMO's 2017 ESOO, for each region in the NEM.[686]

The key findings for each region are:[687]

- **Queensland:** actual operational consumption was 2.8 per cent below forecast. This was due to:
  - Weather was close to normal conditions for both heating and cooling, with a very small impact on annual consumption overall.
  - The forecast overestimated electricity consumption by the Queensland coal seam gas sector.
  - Generation from rooftop PV, which reduces operational consumption, was higher than forecast, driven by larger than forecast growth in installed capacity.
  - Non-scheduled generation reduced operational consumption more than forecast. This was particularly driven by higher than expected non-scheduled PV generation.
- **New South Wales:** actual operational consumption was 0.1 per cent higher than forecast. This was driven by:

686 The Panel's reporting of annual operational consumption is on an 'sent out' basis. 'Sent Out' refers to consumption or demand that excludes generator auxiliary loads.

687 AEMO, *Forecasting accuracy report 2018*, December 2017.

  - The 2017/18 was significantly warmer than normal, resulting in higher consumption for cooling services than forecast.
  - During the 2018 electricity forecasting process, AEMO discovered an error in the loss factor used for New South Wales transmission loss calculation. This has been corrected for the *2018 ESOO*, but the impact can be seen in the 2017 forecast, which was 43.9% lower than actual.
  - Non-scheduled generation was significantly above forecast, primarily driven by higher than forecast non-scheduled PV generation.
- **Victoria:** actual operational consumption was 2.5 per cent below forecast. This was mainly driven by:
  - There were slightly more heating degree days and cooling degree days than average, leading to higher actual consumption compared with forecast.
  - Non-scheduled generation was significantly above forecast, primarily driven by higher than forecast non-scheduled PV generation.
  - Actual growth in residential connections was above forecast.
- **South Australia:** actual operational consumption was 0.8 per cent above the 2017 ESOO forecast. This was due to:
  - Actual weather resulted in a higher need for cooling than forecast.
  - Estimated transmission losses were significantly higher than forecast.[688]
  - Rooftop PV generation was higher than forecast, driven mainly by more installations than forecast.
  - Non-scheduled generation, in particular driven by PV, was also significantly above forecast.
- **Tasmania:** actual operational consumption was 0.1 per cent above forecast. This was driven by:
  - Estimated transmission losses were above forecast.
  - Large industrial consumption was lower than forecast, mainly because assumed expansion in this sector did not eventuate. This was offset by the growth in residential and commercial consumption.

The regional differences between forecast operational consumption and actual operational consumption ranged from -2.8 per cent to 0.8 per cent. The forecast and actual operational consumption values are presented in Table E.1.

688 The *2017 ESOO* transmission loss forecast was based on the average of the transmission loss percentages for the previous five years. These were quite low in the first three years, causing losses to be underestimated compared to the most recent trend. The change in trend is likely to reflect the change in generation mix in South Australia and Victoria, and the corresponding change in transmission flows. In 2017/18, for the first time in over nine years, South Australia was a net exporter of electricity.

Table E.1: **Difference between forecast and actual operational consumption**

REGION	FORECASTED OPERATIONAL CONSUMPTION (GWH)	ACTUAL OPERATIONAL CONSUMPTION (GWH)	DIFFERENCE (GWH)	DIFFERENCE (PER CENT)
Queensland	51,870	50,443	-1,427	-2.8
New South Wales	67,819	67,899	80	0.1
Victoria	43,541	42,471	-1,070	-2.5
South Australia	12,144	12,238	94	0.8
Tasmania	10,372	10,385	13	0.1
NEM	185,746	183,436	-2,310	-1.3

Source: AEMO, *Forecast Accuracy Report 2018*, December 2018.

The regional differences between forecast and actual maximum demand ranged from -8.4 per cent to 9.5 per cent. The forecast maximum demand and actual maximum demand values are presented in Table E.2.

Table E.2: **Difference between forecast and actual maximum demand**

REGION	FORECAST MAXIMUM DEMAND (MW)[1]	ACTUAL MAXIMUM DEMAND (MW)	DIFFERENCE (PER CENT)
Queensland	8,527	9,335	9.5
New South Wales	12,353	12,709	2.9
Victoria	8,299	8,770	5.7
South Australia	2,870	2,947	2.7
Tasmania	1,816	1,664	-8.4

Source: AEMO, *Forecast Accuracy Report 2018*, December 2018.
Note: 1 - The maximum demand forecast figures shown in this column reflect the forecasts with underlying temperatures closest to the temperature recorded on the day actual maximum demand was experienced. For Queensland, New South Wales and Victoria this is the 90 per cent POE forecast, for South Australia this is the 50 per cent POE forecast and for Tasmania this is the 10 per cent POE forecast.

Improvements to the forecasting process

To improve consumption and maximum demand forecasts for the *2018 ESOO*, AEMO implemented the following new methodologies:[689]

689 AEMO, *Forecast Accuracy Report 2018*, December 2018.

- **Improvements to short term business and residential forecast models.** AEMO constructed the short term consumption model using the latest meter data for residential and business consumers up to 30 June 2018.[690] These models improved estimates of weather-sensitive load components.
- **Weather and climate impacts.** AEMO has enhanced the methodology that more dynamically identifies when climate change impacts are likely to drive greater increases in extreme temperature (and maximum demand) than average temperature.
- **PV non-scheduled generation.** For this fast-growing segment covering solar PV installations between 100 kW and 30 MW, AEMO last year assumed the same growth rate as commercial-scale PV (10 kW to 100 kW). This year, AEMO engaged with CSIRO to derive a dedicated forecast of installed capacity for PV non-scheduled generation.
- **Emerging developments in energy storage systems and electric vehicle charging profiles.** Using recently available meter data, AEMO has improved the forecast methodology related to battery and electric vehicle charging to better reflect the growing sophistication in the demand profiles of these activities, technological development and consumer tariff offerings.
- **Improvement in the way AEMO estimates historical auxiliary loads.** AEMO implemented a new process to calculate actual auxiliary loads for generators where AEMO had the data available.
- **Increase in number of simulations in maximum/minimum demand model.** The number of simulations was doubled to create a more stable forecast.

As in previous years, in 2019 AEMO will consult on further forecasting methodology improvements via the Forecasting Reference Group. Focus areas include:

- transparancy, accountability and accuracy
- improvements to maximum and minimum demand forecasts
- consumption drivers.

E.2 ST-PASA and pre-dispatch load forecasting and assessment of supply demand balance

AEMO publishes short term projected assessment of system adequacy (ST-PASA) reports. The ST-PASA makes projections for the six-day period following the pre-dispatch period, on a half-hour basis.

The pre-dispatch process provides projections of the prices and generation dispatch based on market participant bids and offers, and AEMO forecasts of demand and others system conditions. Pre-dispatch data of an aggregate nature (both inputs and outputs) is published to the whole market, with data relating to a specific market participant only available to that participant. The report is published the day before typically just after 12:30 AEST and no

690 Working on such a large dataset has previously not been practical.

later than 16:00 AEST for the following day, with AEMO updating the file every 30 minutes thereafter.[691]

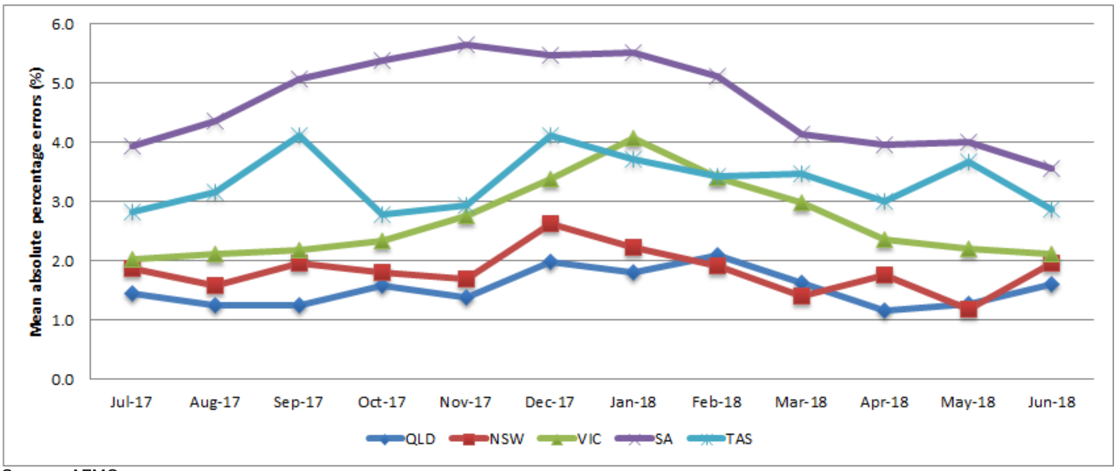
Both ST-PASA and pre-dispatch use the same load forecasting model. With this model, AEMO produces 10 per cent, 50 per cent and 90 per cent POE forecasts for all time frames. The 50 per cent POE forecast is used to set generation targets in pre-dispatch. The 50 per cent and 10 per cent POE forecasts are used to calculate reserve levels for pre-dispatch and ST-PASA periods.[692]

There are a number of inputs that are used by the forecast models for generating the half-hourly demand forecasts:[693]

1. historical actual metered loads (actual load data from January, 2010)
2. real-time actual metered loads (SCADA data from immediately preceding intervals)
3. historical and forecast weather data (temperature and humidity)
4. non-scheduled wind generation forecasts
5. non-scheduled solar generation forecasts
6. small-scale solar generation forecasts
7. type of day (weekday/weekend), school holidays, public holidays and daylight savings information.
8. mandatory restrictions (MR)/RERT schedules.

Figure E.1 shows the mean absolute percentage error for load forecasting 12 hours ahead.

Figure E.1: Load forecasting error - 12 hours ahead



Source: AEMO.

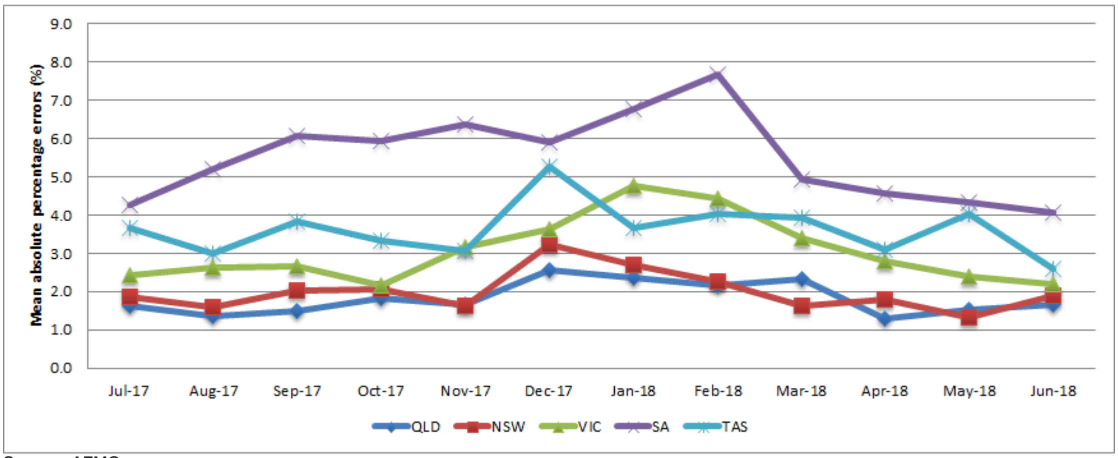
Figure E.2 shows the mean absolute percentage error for load forecasting two days ahead.

691 AEMC, *Reliability frameworks review*, interim report, 19 December 2017.

692 AEMO, *Power system operating procedure - load forecasting*, October 2017.

693 Ibid.

Figure E.2: Load forecasting error - two days ahead



Source: AEMO.

In regard to load forecasting in 2017/18, the Panel notes that:

- Load forecasts were generally more accurate in winter months.
- As in previous years, South Australian load was typically forecast with the least accuracy, whereas load in Queensland and New South Wales was the most predictable.
- As expected, the 12-hour ahead load forecasts were generally more accurate than the two-day ahead forecasts.

E.3 MT-PASA

In addition to ST-PASA reports, AEMO also publishes Medium-term PASA (MT-PASA) reports. MT-PASA assesses of the adequacy of expected electricity supply to meet demand across a two-year horizon through regular assessment of any projected failure to meet the reliability standard.

Each week, scheduled market participants (e.g. generators) must submit forecasts of their availability (total MW capacity available for dispatch) to AEMO for the period covering the next 24 months, commencing eight days (i.e. Sunday) after the publication date of the MT-PASA report. The report is published every week as a minimum. AEMO publishes the MT-PASA every Tuesday at 16:00 AEST with outcomes of the PASA process as well as input variables. Scheduled generators or market participants are required to submit PASA availability of each scheduled generating unit, load or network service and energy constraints for each scheduled generating unit or load.[694] Network service providers must provide planned network outage information.[695]

694 In accordance with clause 3.7.2(d) of the NER. This clause is classified as a civil penalty clause.

695 In accordance with clause 3.7.2(e). This clause is classified as a civil penalty clause.

E.4 Trading intervals affected by price variation

The Panel has considered the number of trading intervals affected by significant variations between pre-dispatch and actual prices during 2017/18 as well as likely reasons for the variations.[696] The data that the Panel has considered is disclosed in Table E.3.

Table E.3: Number of trading intervals affected by price variation

PRICE VARIATION REASON	QUEENSLAND		NEW SOUTH WALES		VICTORIA		SOUTH AUSTRALIA		TASMANIA	
	NO.	(%)	NO.	(%)	NO.	(%)	NO.	(%)	NO.	(%)
Demand	1,885	52%	1,628	51%	2,814	47%	3,627	48%	1,977	31%
Availability	1,282	35%	1,196	38%	2,482	41%	3,023	40%	4,124	64%
Combination	445	12%	358	11%	730	12%	952	13%	325	5%
Network	9	0%	0	0%	1	0%	12	0%	0	0%
Total	3,621	100%	3,182	100%	6,027	100%	7,614	100%	6,426	100%
Trading intervals affected	3,170	18%	2,803	16%	5,300	30%	6,514	37%	5,916	34%

Source: AER.

A comparison of the NEM regions shows that South Australia reported the highest number of significant price variations in 2017/18. For all regions, apart from Tasmania, the majority of price variations were driven by changes in demand. In Tasmania, plant availability was the cause of the majority of price variations.

The Panel notes that the number of trading intervals affected has significantly decreased in all regions from 2016/17.

696 Significant price variations are defined in clause 3.13.7(a) of the rules. Under this clause, the AER must determine whether there is a significant variation between the spot price forecast and actual spot price, it also must then review the reasons for the variation. The AER does this in each of its electricity weekly reports. The AER applies the specific criteria to the 12-hour and four-hour ahead forecasts. The criteria used by the AER could be found here: https://www.aer.gov.au/system/files/Electricity%20rule%203_13_7_a%20criteria%20for%20forecast%20vs%20actual%20price%20variations.pdf

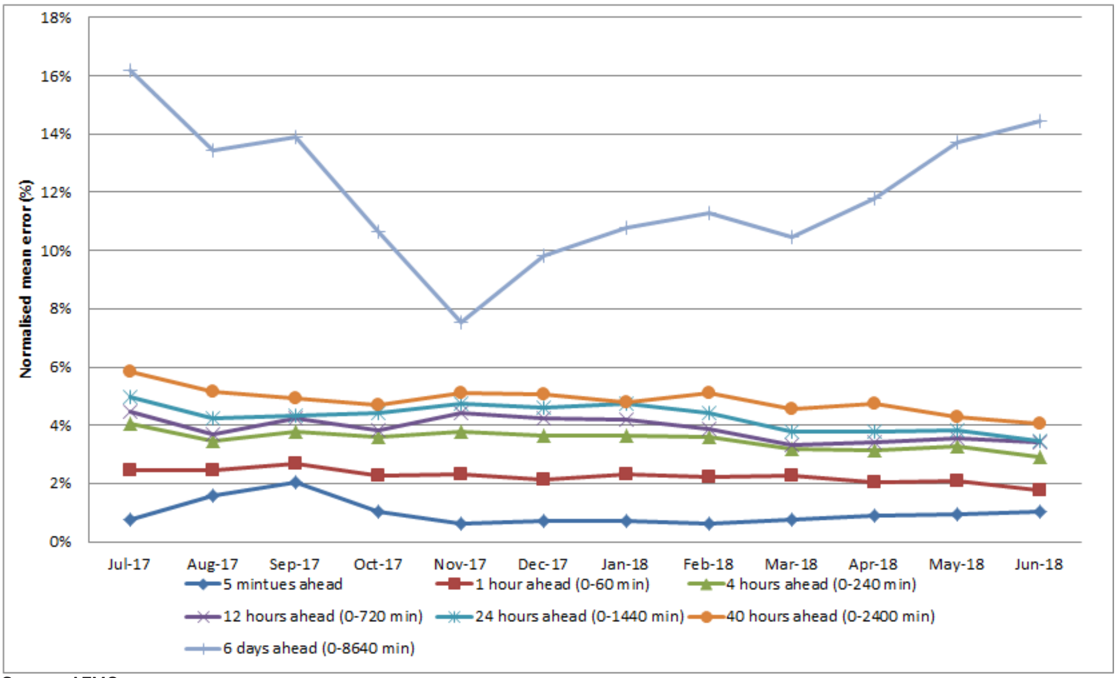
E.5 Wind forecasts

The Australian wind energy forecasting system was developed by AEMO to fulfil its obligation under clause 3.7B of the rules, to prepare forecasts of the available capacity of semi-scheduled generators. It involves statistical, physical and combination models to provide wind generation forecasts using a range of inputs including historical information, standing data (wind farm details), weather forecasts, real time measurements and turbine availability information.

The Panel recognises that wind generation capacity in the NEM is expected to continue to grow. On this basis, the Australian wind energy forecasting system will continue to be an important tool for promoting efficiencies in NEM dispatch, pricing, network stability and security management.

The Panel has considered the performance of the Australian wind energy forecasting system based on the average percentage error across all regions in the NEM. The performance for 2017/18 is depicted in Figure E.3. As could be expected, the accuracy of the forecasts deteriorates as the forecast horizon increases. The highest normalised absolute error values correspond to situations when forecasting is difficult, for example, when there is high or low wind speed.

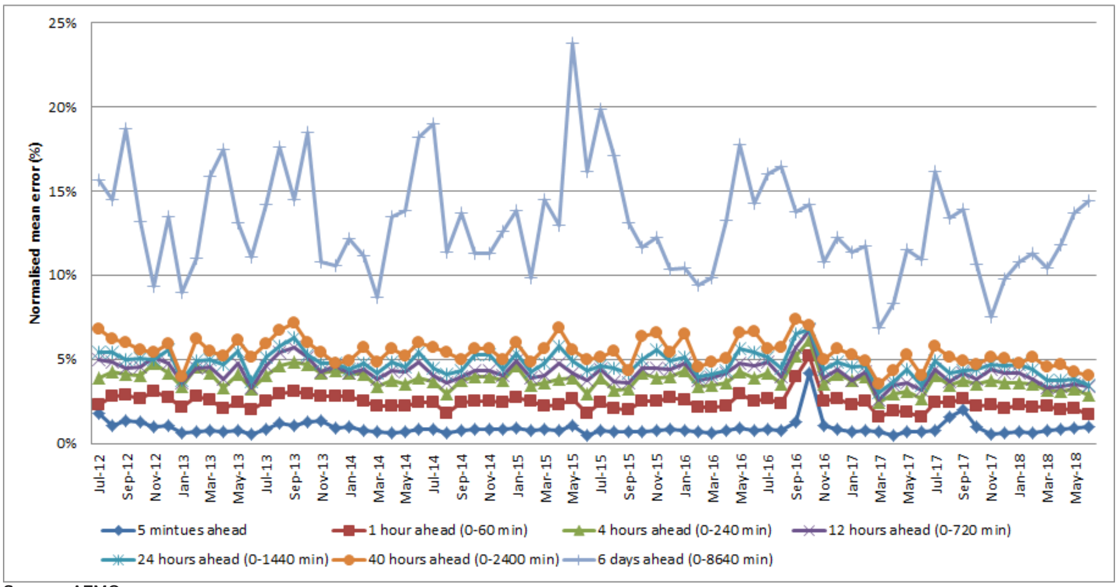
Figure E.3: Australian wind energy forecasts for 2017/18



Source: AEMO.

Figure E.4 shows the performance of the system from 2012/13 to 2017/18. It shows that the forecast error of Australian wind energy forecasting system has been relatively steady and increases in the amount of wind generation appears to have not significantly affected forecast performance.[697]

Figure E.4: Australian wind energy forecasts from 2012 to 2018



Source: AEMO.

697 The Panel notes that figures shown in this chart are percentages. As such, while the percentage error has remained stable, the actual error in absolute terms has increased as the penetration of wind has increased over this period.

F WEATHER SUMMARY

This appendix summarises weather conditions in 2017/18.[698]

F.1 Seasonal weather summary

F.1.1 Winter 2017

Winter 2017 mean temperature was much above Australian average, making this winter being fifth-warmest on record. Exceptionally warm winter daytime temperatures for Australia were observed. Further, mean maximum temperatures were the highest on record for Australia nationally.

The rainfall observed for winter 2017 was the ninth-lowest on record for Australia as a whole, and lowest since 2002. Winter rainfall was 43 per cent below the long term national winter average.

F.1.2 Spring 2017

Across Australia, spring 2017 was exceptionally warm. For Australia as a whole this was sixth-warmest on record spring. Both maximum and minimum temperatures were above to very much above average over the majority of Australia.

Overall, spring rainfall was above long term average by 21 per cent. However, spring rainfall varied significantly across the season and states. September was an extraordinary dry month for Queensland, New South Wales, Victoria and South Australia. In October rainfall was very much above average in eastern and south-western parts of Queensland, and northern New South Wales.

F.1.3 Summer 2017/18

Summer 2017/18 was abnormally warm for Australia, being the second-warmest summer on record. All regions observed mean temperatures for the season amongst the ten warmest on record. Daytime temperatures for summer were above average for all NEM states. Mean minimum temperatures were also above to very much above average for the majority of Australia.

For Australia as a whole summer rainfall was slightly above national long term average, but varied markedly across the country. Overall, it was wetter than average for the west and drier than average for the east of the country. However, December rainfall was very much above average for parts of the south-eastern mainland.

F.1.4 Autumn 2018

For Australia autumn 2018 was extraordinary warm. This was nationally the fourth-warmest autumn on record. Both maximum and minimum temperatures were warmer than long term

698 For more information, see Bureau of Meteorology web-page: http://www.bom.gov.au/climate/current/

autumn averages. In the NEM, only Queensland and Tasmania were ranked outside the top ten for autumn mean maximum temperature.

Rainfall for autumn was below average for most of Australia by 33 per cent. It was much below average across the southern mainland. However, across Queensland's North Tropical Coast rainfall was above average due to very much above average rainfall in March.

F.2 Notable periods during 2017/18

Table F.1 shows the highest and lowest temperatures recorded in the capital of each state in the NEM.

Table F.1: Extreme temperatures (˚C)

CITY	LOWEST TEMPERATURE		HIGHEST TEMPERATURE	
	TEMPERATURE	DATE	TEMPERATURE	DATE
Brisbane (CBD)	5.9	24 July 2017	37.5	14 January 2018
Sydney (Observatory Hill)	5.4	2 July 2017	43.4	7 January 2018
Canberra (Airport)	-8.7	1 July 2017	40.6	7 January 2018
Adelaide (Kent Town)	2.3	28 June 2018	44.1	28 January 2018
Melbourne (Olympic Park)	0.8	2 July 2017	41.7	6 January 2018
Hobart (Ellerslie Road)	0.7	3 July 2017	36.7	28 January 2018

Source: Bureau of Meteorology.

G SECURITY PERFORMANCE

This appendix provides a detailed analysis of the power system's security management, and the measurement of the power system's security performance. The complete review of the power system's security performance is discussed in chapter 5.

G.1 Security management

Maintaining the security of the power system is one of AEMO's key obligations. The power system is deemed to be in a secure operating state when it is in a satisfactory operating state and will return to a satisfactory operating state following the occurrence of any single credible contingency event.

A satisfactory operating state is achieved when:

- the frequency is within the normal operating frequency band
- voltages at all energised busbars at any switchyard or substation are within relevant limits
- the current flows on all transmission lines of the power system are within its ratings
- all other plant forming part of or impacting on the power system is operating within its rating
- the configuration is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment.

A secure or satisfactory operating state depends on the combined effect of controllable plant, ancillary services, and the underlying technical characteristics of the power system plant and equipment.

AEMO determines the total technical requirements for all services needed to meet the different aspects of security from:

- the Panel's power system security and reliability standards
- market rules obligations and knowledge of equipment performance as supplied by the TNSPs
- design characteristics and modelling of the dynamic behaviour of the power system.

This allows AEMO to determine the safe operating limits of the power system and associated ancillary service requirements.

G.1.1 Power system stability

The stability of the power system is its ability to remain within technical limits, and to recover and remain within those limits following a disturbance. As system operator of the NEM, one of AEMO's obligations is to ensure that stability of the power system is adequately maintained. The primary means of achieving this is to carry out technical analysis of any threats to stability.

Generators and TNSPs are required to monitor indicators of system instability, such as responses to small disturbances, and report their findings to AEMO. AEMO is then responsible for analysing the data and determining whether the performance standards have been met. AEMO also uses this data to confirm and report on the correct operation of protection and control systems.

AEMO has a number of real-time monitoring tools, which help it to meet its security obligations. These tools use actual system conditions and network configuration accessed in real-time from AEMO's electricity market management system. These tools include:

- *Contingency analysis*: an online tool used to ensure that all power system equipment remains within its designed capability and ratings.
- *Phasor point and oscillatory stability monitor:* Phasor point is an online tool, which utilises phasor monitoring equipment installed at five locations across the NEM to detect underdamped oscillatory phenomena in the power system that could lead to a security threat.[699] The oscillatory stability monitor uses the same measurements and produces parameter estimates of the three global oscillatory modes in the NEM based on a modal-identification algorithm. Data from both systems is stored to facilitate historical analysis of power system damping performances.
- *Dynamic Security Assessment and Voltage Security Assessment Tool:* this online security analysis tool simulates the behaviour of the power system for a variety of critical network, load and generator faults. The Dynamic Security Assessment undertakes transient stability analysis while the Voltage Security Assessment Tool is used for voltage stability analysis. Historical results are also stored for examination of power system performances as required.
- *NEM-wide high-speed monitoring system:* this high-speed monitoring system provides visibility of the behaviour of the power system during stability disturbances, which is particularly useful for post-event analysis. It is installed and maintained by the TNSPs.

G.2 System restart standard

The system restart standard sets out several key parameters for power system restoration, including the time frame for restoration and how much supply is to be restored. The standard provides AEMO with a target against which it procures system restart ancillary services from contracted SRAS providers, such as generators with SRAS black start capability.

In the event of a major supply disruption, SRAS may be called on by AEMO to supply sufficient energy to restart power stations in order to begin the process of restoring the power system. AEMO's development of the System Restart Plan must be consistent with the system restart standard. The purpose of SRAS is to restore supply following an event that has a widespread impact on a large area – such as an entire jurisdiction.

The system restart standard does not relate to the process of restoring supply to consumers directly following blackouts within a distribution network or on localised areas of the transmission networks. In addition, there is a separate process, developed with input of jurisdictional governments to manage any disruption that involves the operator on a network

699 Underdamped oscillatory phenomena refers to oscillatory stability or the ability of the power system to maintain synchronism after being subjected to a small perturbation without application of a contingency event.

having to undertake controlled shedding of customers. Restoration of load from these localised or controlled events is not covered by the system restart standard.

The system restart standard in place for 2017/18 was determined in August 2013 and remained in effect until 30 June 2018.[700] The system restart standard applicable from 1 July 2018 was determined in December 2016.[701]

Over 2017/18, AEMO undertook a procurement process to acquire system restart services for the period starting 1 July 2018, in accordance with the SRAS Guideline published by AEMO in December 2017. A competitive tender process was conducted for all electrical sub-networks other than Tasmania.[702] All new contracts are for a three-year duration, with options to extend by up to one year at AEMO's discretion, and up to a further year by agreement.[703]

For more information on system restart services, see chapter 5.

G.3 Technical standards framework

The technical standards framework is designed to maintain the security and integrity of the power system by establishing clearly defined standards for the performance of the system overall.

The framework comprises a hierarchy of standards:

- **system standards:** define the performance of the power system, the nature of the electrical network and the quality of power supplied.
- **access standards:** specify the quantified performance levels that plant (consumer, network or generator) must have in order to connect to the power system.

These system standards establish the target performance of the power system overall.

The access standards define the range within which generators may negotiate with network service providers, in consultation with AEMO, for access to the network. AEMO and the relevant network service provider need to be satisfied that the outcome of these negotiations is consistent with their achieving the overall system standards. The access standards also include minimum standards below which access to the network will not be allowed.

The system and access standards are tightly linked. The technical capabilities of connecting generators will affect the ability of the power system to perform at a level required by the system standards.

G.4 Registered performance standards

The technical performance of all generating plant must be registered with AEMO as a performance standard. Registered performance standards for connecting generators are negotiated with AEMO and the relevant NSP and set at a level which falls in the range

700 For more information, see: https://www.aemc.gov.au/sites/default/files/content/System-Restart-Standard-Reliability-Panel.PDF

701 For more information, see: https://www.aemc.gov.au/sites/default/files/2018-08/REL0057%20-%20Review%20of%20the%20System%20Restart%20Standard%20-%20Final%20Standard.pdf

702 As there is only one possible SRAS provider for Tasmania, AEMO directly requested offers from that provider.

703 AEMO, *Non-market ancillary services cost and quantity report 2017-18,* September 2018.

defined by the access standards set out in clause 5.2 of the rules. Once set, a plant's performance standard does not vary unless an upgrade is required. Where that occurs, a variation in the connection agreement is negotiated with AEMO and the NSP.

Registered performance standards represent binding obligations. To ensure a plant meets its registered performance standards on an ongoing basis, participants are required to set up compliance monitoring programs. These programs must be lodged with AEMO. It is considered a breach of the rules if plant does not continue to meet its registered performance standards and compliance program obligations.

The access standards applying to connecting generators were amended in 2018. These amendments aimed to enhance the security of the power system given the challenges created by a changing energy mix. Amendments included changes to the process of negotiating performance standards, requirements for frequency and voltage control capabilities, and the ability to stay connected during disturbances.[704]

G.5 Frequency operating standards

Control of power system frequency is crucial to security. The Panel is responsible for determining the frequency operating standards that cover normal conditions, as well as the period following critical events when frequency may be disturbed. The frequency operating standards also specify the maximum allowable deviations between Australian Standard Time and electrical time (based on the frequency of the power system). The frequency operating standards are the basis for determining the level of quick acting response capabilities, or ancillary service requirements necessary to manage frequency. Tasmania has separate frequency operating standards to the mainland NEM.

The frequency operating standards are currently under review. A revised frequency operating standards became effective from 14 November 2017 and are shown in the tables below.

G.5.1 NEM mainland frequency operating standards

The frequency operating standards that apply on the NEM mainland to any part of the power system other than an island are shown in Table G.1.[705]

Table G.1: **NEM Mainland Frequency Operating Standards - interconnected system**

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Accumulated time error	15 seconds	n/a	n/a
No contingency event or load event	49.75 to 50.25 Hz, 49.85 to 50.15 Hz - 99% of the time	49.85 to 50.15 Hz within 5 minutes	

704 For more information, see: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

705 If a part of the network on the mainland is islanded, the remaining majority of the network is required to meet the interconnected system frequency operating standards.

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Generation event or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
Network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
Separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47 to 52 Hz (reasonable endeavours)	49.5 to 50.5 Hz within 2 minutes (reasonable endeavours)	49.85 to 50.15 Hz within 10 minutes (reasonable endeavours)

Source: Panel, *Frequency operating standard*, November 2017.

The frequency operating standards that apply to an islanded system on the NEM mainland are shown in Table G.2.

Table G.2: NEM Mainland Frequency Operating Standards - island system

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
No contingency event, or load event	49.5 to 50.5 Hz		
Generation event, load event or network event	49 to 51 Hz	49.5 to 50.5 Hz within 5 minutes	
The separation event that formed the island	49 to 51 Hz or a wider band notified to AEMO by a relevant Jurisdictional Coordinator	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple contingency event including a further separation event	47 to 52 Hz (reasonable endeavours)	49.0 to 51.0 Hz within 2 minutes (reasonable endeavours)	49.5 to 50.5 Hz within 10 minutes (reasonable endeavours)

Source: Panel, *Frequency operating standard*, November 2017.

The frequency operating standards that apply to the NEM mainland during supply scarcity are shown in Table G.3.

Table G.3: **NEM Mainland Frequency Operating Standards - during supply scarcity**

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
No contingency event or load event	49.5 to 50.5 Hz		
Generation event, load event or network event	48 to 52 Hz (Queensland and South Australia) 48.5 to 52 Hz (New South Wales and Victoria)	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Protected event	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple contingency event or separation event	47 to 52 Hz (reasonable endeavours)	49.0 to 51.0 Hz within 2 minutes (reasonable endeavours)	49.5 to 50.5 Hz within 10 minutes (reasonable endeavours)

Source: Panel, *Frequency operating standard*, November 2017.

G.5.2 Tasmanian frequency operating standards

The frequency operating standards that apply in Tasmania to any part of the power system other than an island are shown in Table G.4.

Table G.4: **Tasmanian frequency operating standards - interconnected system**

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Accumulated time error	15 seconds		
No contingency event or load event	49.75 to 50.25 Hz 49.85 to 50.15 Hz, 99% of the time	49.85 to 50.15 Hz within 5 minutes	
Load event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Generation event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Network event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minute	
Separation event	46 to 55 Hz	47.5 to 51.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Protected event	47 to 55 Hz	48.0 to 52.0 Hz within	49.85 to 50.15 Hz

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
		2 minutes	within 10 minutes
ultiple contingency event	46 to 55 Hz	47.5 to 51.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Source: Panel, *Frequency operating standard*, November 2017.

The frequency operating standards that apply to an islanded system within Tasmania are shown in Table G.5.

Table G.5: Tasmania frequency operating standards - island operation

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
No contingency event or load event	49.0 to 51.0 Hz		
Load and generation event	48.0 to 52.0 Hz	49.0 to 51.0 Hz within 10 minutes	
Network event	48.0 to 52.0 Hz	49.0 to 51.0 Hz within 10 minutes	
Separation event	47 to 55 Hz	48.0 to 52.0 Hz within 2 minutes	49.0 to 51.0 Hz within 10 minutes
Protected event	47 to 55 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event including a further separation event	47 to 55 Hz (reasonable endeavours)	48.0 to 52.0 Hz within 2 minutes (reasonable endeavours)	49.0 to 51.0 Hz within 10 minutes (reasonable endeavours)

Source: Panel, *Frequency operating standard*, November 2017.

In Tasmania, where it is not feasible to schedule sufficient frequency control ancillary service to limit frequency excursions to within this containment range for generation, network or load events, operation of the UFLS scheme or OFGSS is acceptable on the occurrence of a further contingency event.[706]

G.6 Network constraints

The ability to transfer power across the system is limited by a number of factors including the capacity of the network. Secure operation of the power system requires AEMO to maintain power flows within the capability of the network after allowing for credible contingencies.

706 OFGSS refers to an over frequency generator shedding scheme, UFLS refers to an under frequency load shedding scheme.

NEMDE maximises the value of spot market trading in energy and ancillary services, subject to constraints designed to manage system security. Market participants make bids and offers to consume or produce electricity at various prices in each five minute dispatch interval in a day. Each generator's offers are combined into a merit order, and then dispatched by AEMO based on these bids, offers, constraints and other market conditions.

Where network constraints bind, generators may need to be dispatched from higher in the merit order, potentially resulting in increased wholesale prices. Constraints also represent the physical realities of the network, including network outages, which may affect customers' supply of electricity. Congestion is measured by the frequency and extent to which network constraints bind.

Increased congestion can result from a range of activities and does not necessarily indicate a reduction in network transfer capability. For instance, new generation located a significant distance away from a load centre may increase competition for existing transmission capacity, and so lead to increased congestion on the network.

G.6.1 Network constraint changes

A main driver for new or updated constraint equations is power system changes. These changes are likely to be the addition of, or removal of, either generation or transmission assets.

Table G.6 displays the yearly constraint changes since 2011 in NEMDE.

Table G.6: Number of constraint changes in the NEMDE

CALENDAR YEAR	CONSTRAINT CHANGES
2011	4,776
2012	4,130
2013	5,817
2014	8,121
2015	11,967
2016	10,477
2017	6,756

Source: AEMO*, NEM Constraint Report 2017 summary data,* July 2018.

In 2017, the number of constraint equation changes decreased significantly in comparison to 2016, from 10,477 to 6,756. This was mostly due to the decreases in the number of constraint equation changes in Victoria, South Australia and Tasmania.[707] This demonstrates that in 2017 power system experienced fewer changes than in 2016 and 2015. For more information on constraint equation changes, see chapter 5.

707 AEMO*, NEM Constraint Report 2017 summary data,* July 2018.

G.6.2 Top binding constraints

Binding network constraints have an impact on market participants by constraining generation to ensure system security is maintained. Increasing levels of binding network constraints are an indicator that network augmentation may need to be assessed through the RIT-T to relieve those constraints. Binding constraints may also lead to customer load shedding in order for the network to remain in a secure state.

Table G.7 outlines the top five binding constraints by cumulative marginal value impacting the NEM[708] during 2017 calendar year.

Table G.7: Top five binding constraints by marginal value impacting the NEM in 2017

CONSTRAINT	CUMULATIVE MARGINAL VALUE	DESCRIPTION
F_S+RREG_0035	6,751,450	The 35 MW local pre-contingent regulation FCAS requirement was introduced in October 2015 to ensure that there are adequate sources of regulation FCAS immediately available to manage frequency in South Australia in the event of the region being separated from the rest of the NEM. The requirement was removed from 12 October 2018.
F_S+LREG_0035	6,679,748	
S_WIND_1200_AUTO & S_NIL_STRENGTH_1	4,746,491	Upper limit of 1,295 MW for South Australian asynchronous generation for minimum synchronous generators online for system strength requirements. Automatically swamps out when required combination is online.
S_PLN_ISL2	4,278,377.6	This constraint binds when Yadnarie to Port Lincoln 132

708 Every dispatch interval, NEMDE provides the marginal value of every constraint used in the dispatch process. The marginal value of a constraint is the effect on total dispatch costs of alleviating that constraint by 1 MW. Summing the marginal values of a constraint over some time period gives an indication of the cumulative marginal value of the constraint over the time period. It is important to remember that the cumulative marginal value measures the only marginal cost of a constraint, and not the total cost. For example, in a given dispatch interval the marginal value of a constraint might be $10,000 per MW. This does not mean that alleviating the constraint by 10 MW will yield a benefit of $100,000 – the marginal cost may fall rapidly as the constraint is alleviated, and may even fall to zero, which means the constraint is no longer binding.

CONSTRAINT	CUMULATIVE MARGINAL VALUE	DESCRIPTION
		kV line is out and Port Lincoln units 1 and 2 are islanded.
S_PLN_ISL32	4,152,741.7	This constraint binds when Yadnarie to Port Lincoln 132 kV line is out and Port Lincoln unit 3 is islanded.

Source: AEMO, *NEM Constraint Report 2017 summary data,* July 2018.

G.7 Market notices

Market notices are notifications of events that impact the market, such as advance notice of lack of reserve conditions, status of market systems or price adjustments. They are electronically issued by AEMO to market participants to allow a more informed market response.[709]

AEMO issued 4,531 market notices during 2017/18, compared to 4,520 in 2016/17 and 4,937 in 2015/16. The number and type of market notices issued by AEMO are summarised in Table G.8. During 2017/18, AEMO issued significantly more market notices of the following types relative to the previous two years: market intervention, reclassify contingency and constraints.

Table G.8: Market notices issued by AEMO

TYPE OF NOTICE	NUMBER OF NOTICES		
	2015/16	2016/17	2017/18
Administered price cap	32	78	0
Constraints	3	2	12
General notice	81	173	121
Inter-regional transfer	354	414	386
Market intervention	2	40	335
Market systems	161	159	172
NEM systems	3	0	0
Non-conformance	509	371	320
Power system events	72	76	74
Price adjustments	0	0	3
Prices subject to	781	523	481

709 In accordance with clause 4.8 of the rules.

TYPE OF NOTICE	NUMBER OF NOTICES		
	2015/16	2016/17	2017/18
review			
Prices unchanged	776	518	475
Reclassify contingency	1686	1495	1606
Recall generation capacity	0	0	1
Reserve notice	400	447	269
Settlements residue	56	190	17
Total[1]	4,937	4,520	4,531

Source: AEMO.
Note: 1 - Also includes participant notices.

G.8 Security directions

In 2017/18, all directions issued involved maintaining the system in a secure operating state.

The number of direction events in 2017/18 was the highest of the past ten years. The number of direction events was four times higher than in the past financial year (32 in 2017/18 compared to eight in 2016/17). The Panel notes that a direction event may include multiple individual directions to different generators[710] For instance, between 23 April and 14 May 2018 (22 days) a single direction event occurred in South Australia. Within this single direction event, 27 individual directions were issued to market participants to maintain power system security. AEMO notified the Panel that in 2017/18, in total there were 101 individual power system security directions issued, this compares to eight individual directions issued in 2016/17.

All but one of the direction events in 2017/18 occurred in South Australia. The increase in directions issued could be attributed to the fact that in South Australia certain combinations of synchronous generators must be in service at all times to ensure adequate system strength for secure operation of the South Australian power system. This is discussed in detail in Chapter 5.

Table G.9 lists individual directions issued in 2017/18, as per *Market Event Reports* published by AEMO.

710 The Panel notes that there is no prescribed method, by which to determine the appropriate length of AEMO direction events. These can range from a few hours to, in one case, 21 days (in April-May 2018).

Table G.9: Directions during 2017/18

STATE	DIRECTED PARTICIPANT	ISSUE TIME	CANCELLA-TION TIME	REASON
South Australia	Pelican Point Power Pty Ltd (ENGIE)	04:30, 2 September 2017	06:30, 4 September 2017	Ensure adequate system strength
South Australia	Origin Energy Electricity Ltd	07:33, 17 September 2017	09:05, 17 September 2017	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	18:05, 22 September 2017	17:00, 24 September 2017	Ensure adequate system strength
South Australia	Origin Energy Electricity Ltd	11:35, 23 September 2017	19:15, 24 September 2017	Ensure adequate system strength
South Australia	AGL SAGeneration PtyLtd	14:00, 23 September 2017	17:00, 23 September 2017	Ensure adequate system strength
South Australia	AGL SAGeneration Pty Ltd	14:45, 7 October 2017	17:00 hrs, 8 October 2017	Ensure adequate system strength
South Australia	AGL SAGeneration PtyLtd	20:00, 9 October 2017	07:00, 11 October 2017	Ensure adequate system strength
South Australia	AGL SAGeneration PtyLtd	06:00, 10 October 2017	07:00, 11 October 2017	Ensure adequate system strength
South Australia	AGL SAGeneration PtyLtd	21:30, 10 October 2017	07:00, 11 October 2017	Ensure adequate system strength
South Australia	Pelican PointPower Limited(ENGIE)	13:30, 27 October 2017	22:30, 28 October 2017	Ensure adequate system strength
South Australia	Origin EnergyElectricity Ltd	14:30, 28 October 2017	14:00, 30 October 2017	Ensure adequate system strength
South Australia	AGL SAGeneration PtyLtd	15:00, 28 October 2017	16:00, 29 October 2017	Ensure adequate system strength
South Australia	Origin EnergyElectricity	16:15, 4 November 2017	09:00, 5 November 2017	Ensure adequate system strength

STATE	DIRECTED PARTICIPANT	ISSUE TIME	CANCELLA-TION TIME	REASON
	Ltd			
South Australia	Origin EnergyElectricity Ltd	09:42, 5 November 2017	06:00, 6 November 2017	Ensure adequate system strength
South Australia	Origin EnergyElectricity Ltd	20:00, 1 December 2017	18:00, 3 December 2017	Ensure adequate system strength
South Australia	AGL SAGeneration Pty Ltd	00:00, 2 December 2017	15:00, 3 December 2017	Ensure adequate system strength
South Australia	AGL SAGeneration PtyLtd	14:30, 23 December 2017	13:05, 24 December 2017	Ensure adequate system strength
South Australia	Origin EnergyElectricity Ltd	14:50, 23 December 2017	11:25, 26 December 2017	Ensure adequate system strength
South Australia	AGL SAGeneration PtyLtd	15:10, 23 December 2017	13:30, 26 December 2017	Ensure adequate system strength
South Australia	Origin EnergyElectricity Ltd	20:00, 12 January 2018	06:00, 15 January 2018	Ensure adequate system strength
South Australia	Pelican PointPower Pty Ltd(ENGIE)	20:05, 12 January 2018	07:00, 14 January 2018	Ensure adequate system strength
South Australia	AGL SAGenerationPty Ltd	20:10, 12 January 2018	05:30, 14J anuary 2018	Ensure adequate system strength
South Australia	Pelican PointPower Pty Ltd(ENGIE)	12:29, 14 January 2018	05:00, 15 January 2018	Ensure adequate system strength
South Australia	Origin EnergyElectricity Ltd	18:00, 29 January 2018	10:00, 31 January 2018	Ensure adequate system strength
South Australia	Pelican PointPower Ltd	09:20, 31 January 2018	09:00, 4 February 2018	Ensure adequate system strength
South Australia	Origin EnergyElectricity Limited	12:00, 23 February 2018	06:00, 26 February 2018	Ensure adequate system strength

STATE	DIRECTED PARTICIPANT	ISSUE TIME	CANCELLA-TION TIME	REASON
South Australia	Origin EnergyElectricity Limited	13:02, 17 March 2018	16:00, 17 March 2018	Ensure adequate system strength
South Australia	Origin EnergyElectricity Limited	16:35, 17 March 2018	17:30, 18 March 2018	Ensure adequate system strength
South Australia	Pelican PointPower Pty Ltd(ENGIE)	17:45, 18 March 2018	07:00, 19 March 2018	Ensure adequate system strength
South Australia	Pelican PointPower Pty Ltd(ENGIE)	20:00, 20 March 2018	06:00, 21 March 2018	Ensure adequate system strength
South Australia	Origin EnergyElectricity Limited	13:50, 24 March 2018	07:00, 26 March 2018	Ensure adequate system strength
South Australia	Pelican PointPower Limited(ENGIE)	19:03, 24 March 2018	04:00, 26 March 2018	Ensure adequate system strength
South Australia	AGL SA Generation PtyLtd	19:06, 24 March 2018	05:00, 26 March 2018	Ensure adequate system strength
South Australia	Origin EnergyElectricity Ltd	17:20, 27 March 2018	06:30, 28 March 2018	Ensure adequate system strength
South Australia	Pelican PointPower Ltd	19:50, 27 March 2018	05:00, 28 March 2018	Ensure adequate system strength
South Australia	Origin EnergyElectricity Limited	14:45, 29 March 2018	06:30, 03 April 2018	Ensure adequate system strength
South Australia	Pelican PointPower Pty Ltd (ENGIE)	14:45, 29 March 2018	15:00, 30 March 2018	Ensure adequate system strength
South Australia	Pelican PointPower Pty Ltd (ENGIE)	15:00, 30 March 2018	15:30, 31 March 2018	Ensure adequate system strength
South Australia	Pelican PointPower Pty Ltd (ENGIE)	15:30, 31 March 2018	16:00, 01 April 2018	Ensure adequate system strength
South Australia	Pelican	16:30, 01 April	15:30, 02 April	Ensure adequate

STATE	DIRECTED PARTICIPANT	ISSUE TIME	CANCELLA-TION TIME	REASON
	PointPower Pty Ltd (ENGIE)	2018	2018	system strength
South Australia	AGL SA Generation Pty Ltd	14:47, 29 March 2018	18:30, 31 March 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	21:00, 31 March 2018	18:00, 02 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 07 April 2018	16:00, 12 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 12 April 2018	14:00, 16 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 07 April 2018	16:00, 10 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	21:00, 10 April 2018	16:00, 12 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 12 April 2018	14:00, 16 April 2018	Ensure adequate system strength
South Australia	Pelican Point Power Pty Ltd (ENGIE)	14:15, 07 April 2018	14:30, 08 April 2018	Ensure adequate system strength
South Australia	Pelican Point Power Pty Ltd (ENGIE)	16:30, 12 April 2018	11:00, 16 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	21:00, 10 April 2018	16:00, 12 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 13 April 2018	15:00, 15 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 13 April 2018	17:00, 14 April 2018	Ensure adequate system strength
South Australia	AGL SA	19:30, 14 April	14:00, 16 April	Ensure adequate

STATE	DIRECTED PARTICIPANT	ISSUE TIME	CANCELLA-TION TIME	REASON
	Generation Pty Ltd	2018	2018	system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 13 April 2018	14:00, 16 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	18:25, 23 April 2018	13:00, 1 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	13:00, 1 May 2018	13:00, 4 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	15:25, 4 May 2018	20:00, 5 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	21:05, 5 May 2018	15:30, 6 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:30, 6 May 2018	17:00, 8 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:20, 7 May 2018	16:00, 11 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:30, 11 May 2018	16:00, 12 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	17:00, 12 May 2018	15:00, 13 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	15:00, 13 May 2018	15:00, 14 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	17:20, 8 May 2018	22:00, 9 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	23:15, 9 May 2018	17:00, 12 May 2018	Ensure adequate system strength
South Australia	AGL SA	14:00, 13 May	01:30, 14 May	Ensure adequate

STATE	DIRECTED PARTICIPANT	ISSUE TIME	CANCELLA-TION TIME	REASON
	Generation Pty Ltd	2018	2018	system strength
South Australia	AGL SA Generation Pty Ltd	17:10, 23 April 2018	13:00, 27 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	12:00, 27 April 2018	20:10, 27 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	17:15, 1 May 2018	17:00, 5 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	13:00, 5 May 2018	14:30, 8 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:20, 7 May 2018	17:20, 8 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	23:00, 24 April 2018	16:00, 25 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 26 Apr2018	21:00, 27 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	22:47, 27 April 2018	15:30, 30 April 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:00, 30 April 2018	16:00, 2 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:45, 10 May 2018	13:30, 12 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	17:00, 12 May 2018	14:00, 13 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	18:20, 23 April 2018	10:00, 24 April 2018	Ensure adequate system strength
South Australia	AGL SA	13:25, 2 May	05:00, 4 May	Ensure adequate

STATE	DIRECTED PARTICIPANT	ISSUE TIME	CANCELLA-TION TIME	REASON
	Generation Pty Ltd	2018	2018	system strength
South Australia	AGL SA Generation Pty Ltd	14:30, 6 May 2018	15:30, 7 May 2018	Ensure adequate system strength
South Australia	Origin Energy Electricity Limited	22:30, 9 May 2018	23:30, 9 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	18:00, 23 May 2018	14:00, 24 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:14, 25 May 2018	14:00, 27 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	14:14, 25 May 2018	13:00, 27 May 2018	Ensure adequate system strength
South Australia	AGL SA Generation Pty Ltd	15:00, 27 May 2018	16:00, 29 May 2018	Ensure adequate system strength
Queensland	Origin Energy Limited	10:25, 22 May 2018	11:05, 22 May 2018	Trip of multiple network elements at the Ross substation

Source: AEMO, *Market Event Reports*.

H REVIEWABLE OPERATING INCIDENTS DURING 2017/18

AEMO is required to conduct a review of every reviewable operating incident. A reviewable operating incident is defined in the rules as:[711]

- a non-credible contingency event or multiple contingency events on the transmission system
- a black system condition
- an event where the frequency of the power system is outside limits specified in the power system security standard
- an event where the power system is not in a secure operating state for more than 30 minutes
- an event where AEMO issues an instruction for load shedding
- an incident where AEMO has been responsible for the disconnection of a Registered Participant or
- any other operating incident identified to be of significance to the operation of the power system or a significant deviation from normal operating conditions.

The Panel is required to assess the number and types of reviewable operating incidents in the NEM. The Panel also assesses how AEMO manages the process of identifying and reviewing these incidents to determine whether AEMO's processes can be improved.[712]

In 2017/18, there were 24 incidents that were reviewed in accordance with the operating incident guidelines.[713] Table H.1 classifies and compares the type and number of incidents with 2016/17.

Table H.1: Reviewable operating incidents 2016/17 and 2017/18

INCIDENT TYPE	NUMBER OF INCIDENTS	
	2016/17	2017/18
Transmission related incidents (excluding busbar trips)	10	12
Generation related incidents	1	0
Combined transmission and generation incidents	2	1
Busbar related reviewable incidents	7	11

711 Clause 4.8.15 of the rules.

712 The guidelines for identifying reviewable operating incidents can found on the AEMC Reliability Panel website: www.aemc.gov.au.

713 For more information see: http://www.aemc.gov.au/getattachment/50c858eb-8f96-4164-bdad-ccf12b22827f/Final-revised-guidelines.aspx

INCIDENT TYPE	NUMBER OF INCIDENTS	
	2016/17	2017/18
Power system security related incidents	9	0 (At the time of publication, there was one incident still under AEMO's review that may fall into this category, it is currently allocated to ''Transmission related incidents")
Total	**29**	**24**

Source: AEMO.

The table above shows that in 2017/18 five less reviewable operating incidents occurred than in 2016/17. However, the total number of incidents can fluctuate significantly each year and there is no evidence of any trend regarding the annual number of incidents.[714]

714 For example, in 2014/15 there were 28 reviewable incidents.

I SAFETY FRAMEWORK

As noted in Chapter 2, network service providers and other market participants have specific responsibilities to provide for the safety of personnel and the public. The electrical system is designed with extensive safety systems to provide for the protection of the system itself, workers and the public. Each NEM region is subject to different safety requirements as set out in the relevant jurisdictional legislation. State and territory legislation governs the safe supply of electricity by network service providers and the broader safety requirements associated with electricity use in households and businesses.

Examples of the different jurisdictional safety arrangements are provided below. The Panel considers it is of benefit to provide an overview of some jurisdictional arrangements to provide context to issues that may be relevant to stakeholders. The Panel notes this is not an exhaustive summary of safety requirements in each region.

Network constraints, developed from TNSP limit advice, are used by AEMO in the NEM dispatch process to ensure that plant remains within rating and power transfers remain within stability limits so that the power system is in a secure operating state.[715] Should AEMO not be able to manage secure and satisfactory limits through the use of network constraints, the following options will be used. These options are listed in AEMO's suggested priority order and may not all be available under all circumstances:[716]

- Revision to generator thermal ratings.
- Revision to power system limits.
- Implement plan agreed between AEMO and relevant registered participants (e.g. Contingency plan, Network Support Agreement (NSA)).
- Reconfigure network
- Dispatch or activation of reserve contracts to address a power system security event.
- System security direction or instruction issued under clause 4.8.9 of the rules.
- If sufficient raise FCAS are unavailable, use system security constraints to reduce the size of the largest generation at risk. If sufficient lower FCAS are unavailable, issue a direction under section 116 of NEL[717] for a reduction in the size of the largest load at risk.
- Instruct involuntary load shedding.

I.1 Queensland

In Queensland, the Electrical Safety Office is the electrical safety regulator that undertakes a range of activities to support electrical safety with the key objective of reducing the rate of electrical fatalities in Queensland. The Electrical Safety Act 2002 (Qld) places obligations on people who may affect the electrical safety of others. This stand-alone legislation established a Commissioner for Electrical Safety, an Electrical Safety Board and three Board committees

715 AEMO, *Power system security guidelines*, December 2018.

716 Ibid.

717 Which will be a direction where it applies to scheduled load, and otherwise will be an instruction issued under clause 4.8.9 of the rules.

to advise the Minister on electrical safety issues. Additionally, an independent state-wide electrical safety inspectorate was established to administer and enforce the legislative requirements.

I.2 New South Wales

In New South Wales, IPART is the safety and reliability regulator for electricity networks under the Electricity Supply Act 1995 (NSW) and the *Electricity Supply (Safety and Network Management) Regulation 2014 (NSW)*. IPART strives to ensure safe and reliable supply of electricity for the benefit of the New South Wales community (including employees of the network operators) and the environment.

IPART has been granted new compliance and enforcement powers with an overall objective to:

- maintain safety standards within electricity networks
- meet relevant reliability standards set by government.

Electricity networks continue to have the ultimate responsibility for network safety and reliability. IPART holds these utilities accountable by developing an effective risk based compliance and enforcement framework.

The NSW Fair Trading monitors the safety of customer electrical installations under the Electricity (Consumer Safety) Act 2004 (NSW) and *Electricity (Consumer Safety) Regulation 2015 (NSW)*.[718] SafeWork NSW monitors the safety of work places under the Work Health and Safety Act 2011 (NSW) and *Work Health and Safety Regulation 2011 (NSW)*. The NSW Department of Industry authorises accredited service providers under the Electricity Supply Act 1995 (NSW) and the *Electricity Supply (General) Regulation 2014 (NSW)*.

I.3 Australian Capital Territory

The ACT Environment, Planning and Sustainable Development Directorate - Environment administers the Electricity Safety Act 1971 (ACT) and *Electricity Safety Regulation 2004 (ACT)* in the Australian Capital Territory. This regulation ensures electrical safety, particularly in relation to:

- the installation, testing, reporting and rectification of electrical wiring work for an electrical installation and its connection to the electricity distribution network (the Wiring Rules are the relevant standard)
- the regulation and dealings associated with the sale of prescribed and non-prescribed articles of electrical equipment
- the reporting, investigation and recording of serious electrical accidents by responsible entities

718 These regulations have now been repealed and replaced with the Gas and Electricity (Consumer Safety) Act 2017 (NSW) (commenced 01.09.2018) and *Gas and Electricity (Consumer Safety) Regulation 2018* (commenced 01.09.2018).

- enforcement by Access Canberra and its electrical inspectors (including inspectors' identification, entry powers, seizing evidence, disconnection of unsafe installations and articles, powers to collect verbal and physical evidence and respondents' rights)
- the appeals system
- miscellaneous matters such as certification of evidence.

I.4 Victoria

Electricity safety in Victoria is regulated by Energy Safe Victoria. The role of Energy Safe Victoria involves overseeing the design, construction and maintenance of electricity networks across the state and ensuring every electrical appliance in Victoria meets safety and energy efficiency standards before it is sold. Energy Safe Victoria oversees a statutory regime that requires major electricity companies to submit and comply with their Electricity Safety Management Scheme, submit bush fire mitigation plans annually for acceptance and electric line clearance management plans annually for approval, and to actively participate in Energy Safe Victoria audits to test compliance of their safety systems.

I.5 South Australia

In South Australia, the Office of the Technical Regulator is responsible for the administration of the *Electricity Act 1996 (SA)* and *Energy Products (Safety and Efficiency) Act 2000 (SA)*. The primary objective of these Acts is to ensure the safety of workers, consumers and property as well as compliance with legislation, technical standards and codes in the electricity industries.

The principal functions of the Office of the Technical Regulator under the *Electricity Act 1996 (SA)* are:

- monitoring and regulation of safety and technical standards in the electricity supply industry
- monitoring and regulation of safety and technical standards relating to electrical installations
- administration of the provisions of the Act relating to clearance of vegetation from power lines
- fulfilling any other function assigned to the Technical Regulator under the Act.

I.6 Tasmania

Until 1 June 2010, several safety functions were vested with the Office of the Tasmanian Economic Regulator under the *Electricity Industry Safety and Administration Act 1997 (Tas)* and the *Electricity Supply Industry Act 1995 (Tas)*. The *Electricity Industry Safety and Administration Act 1997 (Tas)*:

- provides for electrical contractors and workers to be appropriately qualified and regulated
- establishes safety standards for electrical equipment and appliances
- provides for the investigation of electrical safety accidents in the electricity industry.

Safety-related responsibilities were transferred to Work Safe Tasmania via an amendment to the *Electricity Industry Safety and Administration Act 1997 (Tas*) in 2009.

J PRICING REVIEW

This appendix summarises the major pricing events during 2017/18.

The AER is required to publish a report whenever the electricity spot price exceeds $5000/MWh in accordance with clause 3.13.7 (d) the NER. These reports are designed to examine market events and circumstances that contributed to wholesale market price outcomes. Specifically, the AER's reports:

- describe the significant factors contributing to the spot price exceeding $5000/MWh, including withdrawal of generation capacity and network availability
- assess whether rebidding contributed to the spot price exceeding $5000/MWh
- identify the marginal scheduled generating unit
- identify all units with offers for the trading interval equal to or greater than $5000/MWh and compare these dispatch offers to relevant dispatch offers in previous trading intervals.

The AER is required to monitor significant variations between forecast and actual ancillary service prices and publish a report where:

- prices for a market ancillary service over a period significantly exceed the relevant spot price for energy
- prices for a market ancillary service exceed $5000/MW for a number of trading intervals within that period.

In accordance with the clause 3.13.7(e) of the NER, the reports must:

- describe the significant factors that contributed to the ancillary service prices exceeding $5000/MW
- identify any linkages between spot prices in the energy market and ancillary service prices contributing to the occurrence
- assess whether rebidding pursuant to clause 3.8.22 of the rules contributed to prices exceeding $5000/MW.

Table J.1 lists the spot price events in the NEM during 2017/18.

- The event on 18 January 2018 can be attributed to high temperatures in Melbourne (reaching a maximum of 40ºC) and in Adelaide (reaching a maximum of 43ºC). Even though participants offered capacity at low prices, it was not enough to satisfy the level of demand for electricity.[719]
- The event on 19 January 2018 occurred mainly due to high temperatures leading to high demand for electricity. The majority of capacity in both regions was priced in very low price bands, a small amount in very high price bands and almost no mid-priced capacity. As a result, small increases in demand at the top end of low priced capacity had the

719 AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia,18 January 2018*, March 2018. Available at: https://www.aer.gov.au/system/files/Prices%20above%20%245000MWh%20-%2018%20January%202018%20%28Vic%20SA%29_0.pdf

potential to lead to high prices. Due to the ever tightening supply and demand balance in both regions, at around 14.00, AEMO activated RERT contracts in Victoria and South Australia.[720]

- The event on 7 February 2018 was mainly driven by high temperatures in Victoria and South Australia, leading to higher than average demand. To meet customer demand in the two regions, electricity from high-priced local sources was required, resulting in high prices.[721]

Table J.1: Spot price events for July 2017 to June 2018

DATE	REGION	TRADING INTERVALS	PRICE PER MWH
18 January 2018	Victoria	16.30 to 18.00	$5,079 to $12,931
	South Australia		$5,693 to $14,167
19 January 2018	Victoria	14.30	$10,152[1]
	South Australia	14.30, 15.00, 17.00 and 18.00	$11,864, $13,408, $5,413 and $5,332, respectively[1]
7 February 2018	Victoria	16.00	$6,847
	South Australia		$8,001

Source: AER, *Electricity spot prices above $5000/MWh,* available at: https://www.aer.gov.au/wholesale-markets/market-performance
Note: 1 - On 19 January 2018, at around 14.00, AEMO activated RERT contracts in Victoria and South Australia. The prices in the table for 19 January 2018 are 'what if' prices. The "what-if" attempts to calculate what the price would have been had AEMO not intervened in the market. This effectively removes the effects of the RERT contracts thereby preserving the market price signal.

Table J.2 summarises the FCAS price events in the NEM during 2017/18. FCAS pricing events could be attributed to the pre-contingent regulation FCAS requirement in South Australia. AEMO introduced the 35 MW local requirement in October 2015 to ensure that there are adequate sources of regulation FCAS immediately available to manage frequency in South Australia in the event of the region being separated from the rest of the NEM. The requirement was removed from 12 October 2018.[722]

720 AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia,19 January 2018*, March 2018. Available at: https://www.aer.gov.au/system/files/Prices%20above%20%245000MWh%20-%2019%20January%202018%20%28Vic%20SA%29.pdf

721 AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia,7 February 2018*, April 2018. Available at: https://www.aer.gov.au/system/files/D18-48817%20Prices%20above%20%245000MWh%20-%207%20Feb%202018%20%28SA%20Vic%29.PDF

722 For more information on the requirement, see chapter 3.

Table J.2: **FCAS price events from July 2017 to June 2018**

DATE	REGION	FCAS SERVICE	TRADING INTERVALS	PRICE PER MWH
28 August 2017	South Australia	Raise Regulation	11.00 to 19.00	$9,999 to $11,602
		Lower Regulation		$9,999 to $11,018
14 September 2017	South Australia	Raise Regulation	09.00 to 16.30	$10,969 and $11,508
		Lower Regulation		$10,969 and $11,509
13 October 2017	South Australia	Raise Regulation	11 trading intervals between 07.30 and 13.30	$9,999 to $10,699
		Lower Regulation	13 trading intervals between 07.30 and 13.30	
14 October 2017	South Australia	Raise Regulation	6 trading intervals between 06.30 and 09.00	$9,499
		Lower Regulation	4 trading intervals between 06.30 and 09.00	
24 October 2017	South Australia	Raise Regulation	19.00 to 20.30	$10,642 to $11,499
		Lower Regulation	18.30 to20.30	$4,698 to $13,271

Source: AER, *Reports into market ancillary service prices above $5000/MW,* available at: https://www.aer.gov.au/wholesale-markets/market-performance

K MARKET PRICE CAP AND CUMULATIVE PRICE THRESHOLD

On 30 April 2018, the Panel published the final report on the *Reliability standard and settings review*.[723] In accordance with the rules, the Panel is required to review the market price cap and cumulative price threshold every four years.

The market price cap and cumulative price threshold focus on the future performance of the NEM. Their purpose is to:

- Maintain the overall integrity of the market, by protecting market participants and consumers from excessively high prices.
- Allow for sufficient investment to provide electricity to the agreed reliability standard.

The Panel recommended to leave market price cap and cumulative price threshold for the NEM unchanged for the period 1 July 2020 – 1 July 2024.

Table K.1: **Market price cap and cumulative price threshold**

COMPONENT AND PURPOSE	RECOMMENDED LEVEL
Market price cap: Limits market participants' exposure to temporary high prices, being the maximum bid (and therefore settlement) price that can apply in the wholesale spot market. It should be set at a level such that prices over the long term incentivise enough new investment in generation so the reliability standard is expected to be met.	$14,200/MWh ($2017)
Cumulative price threshold: Limits participants' financial exposure to prolonged high prices, by capping the total market price that can occur over seven consecutive days. It should be set at a level such that prices over the long term incentivise enough new investment in generation so the reliability standard is expected to be met.	$212,800 ($2017)

Source: Reliability Panel, *Reliability standard and settings review,* final report, 30 April 2018.
Note: Both the value of the market price cap and the cumulative price threshold will remain indexed to CPI.

The Panel considered this appropriate as:

723 For more information on the reliability standard and settings review, see the project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018#

- The present levels of the market price cap and cumulative price threshold are each sufficiently low to serve the purpose of limiting market participants' exposure to very high prices (temporary and sustained, respectively) and thereby safeguard the overall integrity of the market.
- The current level of the settings are likely to continue to be sufficiently high to allow investment in enough generation so there is not more expected unserved energy than that allowed for by the reliability standard without the use of AEMO's powers to intervene.
- Providing regulatory stability through no changes will benefit consumers and market participants, given the current impact of policy uncertainty on investor confidence, the rapid technological change underway in the NEM.

Since 1 July 2012, the rules have required the AEMC to annually update the values for the market price cap and cumulative price threshold by applying consumer price index information published by the Australian Bureau of Statistics.

The AEMC is required to publish these values by 28 February each year. For 2017/18, the values for the market price cap and the cumulative price threshold are tabulated in Table K.2.

Table K.2: **2017/18 market price cap and cumulative price threshold values**

	FROM 1 JULY 2016 TO 30 JUNE 2017	FROM 1 JULY 2017 TO 30 JUNE 2018
Market price cap	$14,000 / MWh	$14,200/MWh
Cumulative price threshold	$210,100	$212,800

Market price cap

During 2017/18, the market price cap was reached during 32 dispatch intervals in the energy market, 26 of these occurred in South Australia. The market price cap was reached 45 times in FCAS markets.[724] This represents a significant change from 2016/17, when the market price cap was reached 170 times in the energy market and 66 times in FCAS markets.

Cumulative price threshold

During 2017/18, the cumulative price threshold was not reached in the energy and FCAS markets.

724 Market price cap events in FCAS markets occurred 25 times in Tasmania, 14 times in South Australia and 6 times in Queensland.

L ENVIRONMENTAL AND RENEWABLE ENERGY POLICIES

This section provides a high level summary of changes to, and introduction of significant environmental policies relevant to the reliability, security and safety of the NEM during 2017/18.

L.1 Emissions reduction fund

In 2015, *the Carbon Credits (Carbon Farming Initiative) Act 2011* was amended to establish the Emissions Reduction Fund.[725] The Emissions Reduction Fund builds on the Carbon Farming Initiative, expanding coverage to encourage emissions reductions across the economy. The Emissions Reduction Fund comprises three parts:

- **Crediting:** businesses identify emissions reductions and would earn credits for effecting these emissions reductions.
- **Purchasing:** businesses with a registered project have an opportunity to sell their Australian carbon credit units to the Australian Government, represented by the Clean Energy Regulator. The Clean Energy Regulator runs auctions to select the lowest cost abatement. If a business' bid is successful at auction, they automatically enter into a contract with the Clean Energy Regulator to deliver Australia carbon credit units.
- **Safeguarding:** the safeguard mechanism makes sure that emissions reductions paid for by the Emissions Reduction Fund are not displaced by a significant rise in emissions above business-as-usual levels elsewhere in the economy. The safeguard mechanism commenced on 1 July 2016.

L.2 Meeting 2030 emissions reduction commitments

Australia has committed to emissions reductions of 26-28 per cent on 2005 levels by 2030. The Emissions Reduction Fund, discussed above, is a major component of Australia's commitment to meeting the emissions reductions target. This is complemented by the Renewable Energy Target, energy efficiency improvements, phasing out very potent synthetic greenhouse gases, and direct support for investment in low emissions technologies and practices.

In December 2017 the Commonwealth Government Department of the Environment and Energy published its *Review of climate change policies.* The report found that Australia was on track to meet its 2030 target.[726]

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725 For more information on the Emissions Reduction Fund, see: https://www.environment.gov.au/climate-change/emissions-reduction-fund

726 Australian Government Department of the Environment and Energy, *2017 Review of climate change policies,* December 2017.

L.3 Renewable energy target

Since January 2011, the Renewable Energy Target (RET) scheme has operated in two parts: the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET).

The LRET creates a financial incentive for the establishment or expansion of renewable energy power stations, such as wind and solar farms or hydro-electric power stations. It does this by legislating demand for Large-scale Generation Certificates (LGCs). One LGC can be created for each megawatt-hour of eligible renewable electricity produced by an accredited renewable power station. LGCs can be sold to entities (mainly electricity retailers) who surrender them annually to the Clean Energy Regulator to demonstrate their compliance with the LRET scheme's annual targets. The revenue earned by the power station for the sale of LGCs is additional to that received for the sale of the electricity generated.

The LRET includes legislated annual targets which will require significant investment in new renewable energy generation capacity in coming years. Amending legislation to implement the Government's reforms to the LRET was agreed to by the Australian Parliament on 23 June 2015. Due to these amendments, the large-scale targets ramp up until 2020 when the target will be 33,000 GWh of renewable electricity generation. Prior to the amendments the target was 41,000 GWh of renewable energy by 2020. In January 2018, the Clean Energy Regulator announced that it expected the LRET to be met before the 2020 deadline due to strong investment in renewable energy.[727] While the LRET's 33,000 GWh target is expected to be met before the 2020 deadline, the scheme will continue to require high-energy users to meet their obligations under the policy until 2030.

SRES provides a financial incentive for individuals and businesses to install small-scale renewable energy systems such as rooftop solar, solar water heaters and heat pumps. This occurs in the form of small-scale technology certificates (STCs), which are issued up front for a system's expected power generation (based on its installation date and geographical location) until the SRES expires in 2030. Similar to the LRET, large energy users are required to purchase a fixed proportion of STCs and surrender them to meet their obligations under the RET.

L.4 Jurisdiction-based renewable energy targets

Some active jurisdictional schemes include:

- **Australian Capital Territory:** 100 per cent of generation provided to the Australian Capital Territory to come from renewable sources by 2020. This is given effect by a reverse auction of two-way contracts for difference.[728]

727 Clean Energy Regulator, *Large-scale generation certificate market update - January 2018.* For more information, see: http://www.cleanenergyregulator.gov.au/RET/Pages/About%20the%20Renewable%20Energy%20Target/How%20the%20scheme%20works/Large-scale%20generation%20certificate%20market%20update%20by%20month/Large-scale-generation-certificate-market-update-January-2018.aspx

728 For more information, see: https://www.environment.act.gov.au/energy/cleaner-energy/renewable-energy-target-legislation-reporting

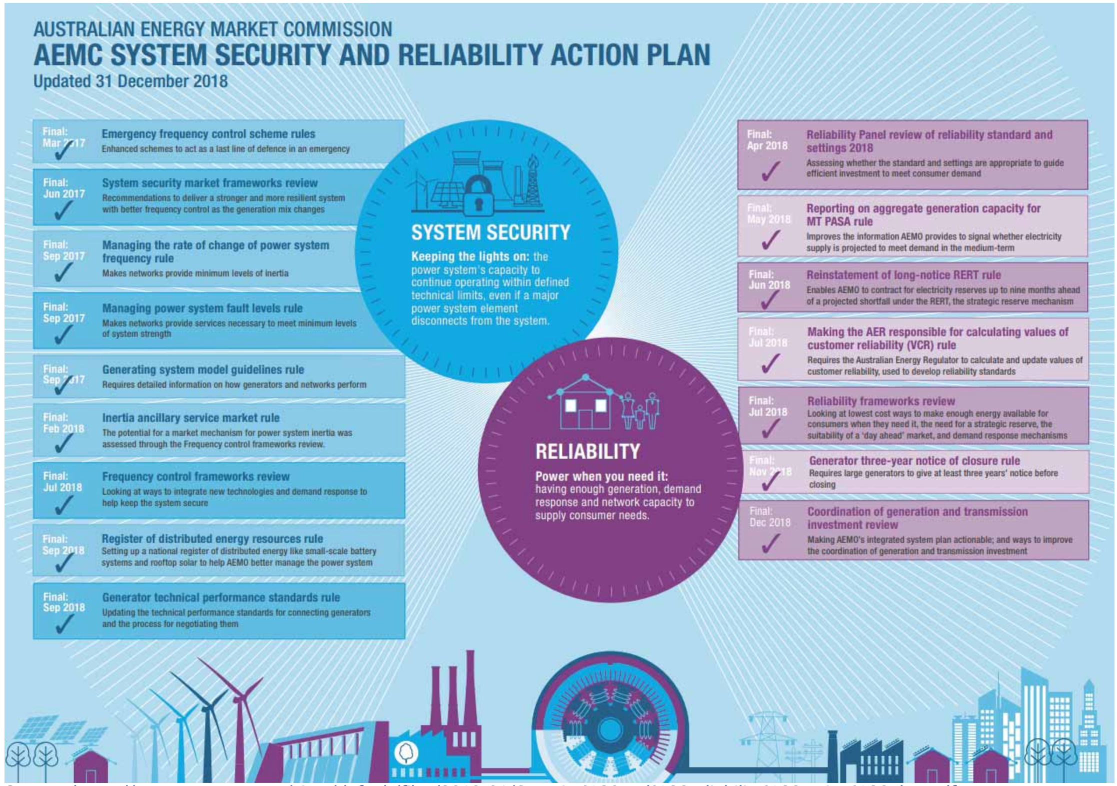
- **Queensland:** 50 per cent of generation provided to Queensland to come from renewable sources by 2030. Among other initiatives, the Queensland government conducts a reverse auction for up to 400 megawatts of renewable energy capacity, including 100 megawatts of energy storage.[729]
- **Victoria:** 25 per cent of generation provided to Victoria to come from renewable sources by 2020, and 40 per cent by 2025. This is also given effect through a reverse auction of two-way contracts for difference, and the generation will be located within Victoria.[730]

729 For more information, see: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland

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

M AEMC'S SECURITY AND RELIABILITY WORK PROGRAM

Figure M.1: AEMC's security and reliability work program



Source: https://www.aemc.gov.au/sites/default/files/2019-01/Security%20and%20reliability%20action%20plan.pdf

GLOSSARY

Available capacity	The total MW capacity available for dispatch by a scheduled generating unit or scheduled load (i.e. maximum plant availability) or, in relation to a specified price band, the MW capacity within that price band available for dispatch (i.e. availability at each price band).
Busbar	A busbar is an electrical conductor in the transmission system that is maintained at a specific voltage. It is capable of carrying a high current and is normally used to make a common connection between several circuits within the transmission system. The rules define busbar as 'a common connection point in a power station switchyard or a transmission network substation'.
Cascading outage	The occurrence of a succession of outages, each of which is initiated by conditions (e.g. instability or overloading) arising or made worse as a result of the event preceding it.
Contingency events	These are events that affect the power system's operation, such as the failure or removal from operational service of a generating unit or transmission element. There are several categories of contingency event, as described below: • credible contingency event is a contingency event whose occurrence is considered "reasonably possible" in the circumstances. For example: the unexpected disconnection or unplanned reduction in capacity of one operating generating unit; or the unexpected disconnection of one major item of transmission plant • non-credible contingency event is a contingency event whose occurrence is not considered "reasonably possible" in the circumstances. Typically a non-credible contingency event involves simultaneous multiple disruptions, such

	as the failure of several generating units at the same time.
Customer average interruption duration index (CAIDI)	The sum of the duration of each sustained customer interruption (in minutes) divided by the total number of sustained customer interruptions (SAIDI divided by SAIFI). CAIDI excludes momentary interruptions (one minute or less duration).
Directions	Under s. 116 of the NEL, AEMO may issue directions. Section 116 directions may include directions as issued under clause 4.8.9 of the NER (e.g. directing a scheduled generator to increase output) or an instruction issued under clause 4.8.9 of the rules (e.g. instructing a network service provider to load shed). AEMO directs or instructs participants to take action to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.
Dispatch	The act of initiating or enabling all or part of the response specified in a dispatch bid, dispatch offer or market ancillary service offer in respect of a scheduled generating unit, a scheduled load, a scheduled network service, an ancillary service generating unit or an ancillary service load in accordance with NER rule 3.8, or a direction or operation of capacity the subject of a reserve contract as appropriate.
Distribution network	The apparatus, equipment, plant and buildings (including the connection assets) used to convey and control the conveyance of electricity to consumers from the network and which is not a transmission network.
Distribution network service provider (DNSP)	A person who engages in the activity of owning, controlling, or operating a distribution network.
Forecasting uncertainty measure (FUM)	The FUM is the number of MW representing the quantity of error in reserves for which AEMO determines, at a certain confidence level, that the error will not exceed this value. In other words, it is the size of the

	adjustment to be made based on AEMO's modelling of reserve errors.
Frequency control ancillary services (FCAS)	Those ancillary services concerned with balancing, over short intervals, the power supplied by generators with the power consumed by loads (throughout the power system). Imbalances cause the frequency to deviate from 50 Hz.
Frequency operating standard	The frequency operating standard defines the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies. Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the frequency operating standard, while AEMO is responsible for maintaining the frequency within the ranges defined by the standard.
Interconnector	A transmission line or group of transmission lines that connect the transmission networks in adjacent regions.
Jurisdictional planning body	The transmission network service provider responsible for planning a NEM jurisdiction's transmission network.
Lack of reserve	This is when reserves are below specified reporting levels.
Load	A connection point (or defined set of connection points) at which electrical power is delivered, or the amount of electrical power delivered at a defined instant at a connection point (or aggregated over a defined set of connection points).
Load event	In the context of frequency control ancillary services, a load event: involves a disconnection or a sudden reduction in the amount of power consumed at a connection point and results in an overall excess of supply.
Load shedding	Reducing or disconnecting load from the power system either by automatic control systems or under instructions from AEMO.

	Load shedding will cause interruptions to some energy consumers' supplies.
Low reserve condition (LRC)	This is when reserves are below the minimum reserve level.
Momentary average interruption frequency index (MAIFI)	The total number of customer interruptions of one minute or less duration, divided by the total number of distribution customers.
Medium term projected assessment of system (MT PASA) (also see ST PASA)	A comprehensive programme of information collection, analysis and disclosure of medium-term power system reliability prospects. This assessment covers a period of 24 months and enables market participants to make decisions concerning supply, demand and outages. It must be issued weekly by AEMO.
Minimum reserve level (MRL)	The minimum reserve margin calculated by AEMO to meet the reliability standard.
Ministerial Council on Energy (MCE)	The MCE is the national policy and governance body for the Australian energy market, including for electricity and gas, as outlined in the COAG Australian Energy Market Agreement of 30 June 2004.
National Electricity Code	The National Electricity Code was replaced by the National Electricity Rules on 1 July 2005.
National electricity market (NEM)	The NEM is a wholesale exchange for the supply of electricity to retailers and consumers. It commenced on 13 December 1998, and now includes Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia, and Tasmania.
National Electricity Law (NEL)	The NEL is contained in a schedule to the National Electricity (South Australia) Act 1996. The NEL is applied as law in each participating jurisdiction of the NEM by the application statutes.
National Electricity Rules (NER)	The NER came into effect on 1 July 2005, replacing the National Electricity Code.
Network	The apparatus, equipment and buildings used to convey and control the conveyance of electricity. This applies to both transmission and distribution networks.
Network capability	The capability of a network or part of a network to transfer electricity from one

	location to another.
Network control ancillary services (NCAS)	Ancillary services concerned with maintaining and extending the operational efficiency and capability of the network within secure operating limits.
Network event	In the context of frequency control ancillary services, the tripping of a network resulting in a generation event or load event.
Network service providers	An entity that operates as either a transmission network service provider (TNSP) or a distribution network service provider (DNSP).
Network services	The services (provided by a TNSP or DNSP) associated with conveying electricity and which also include entry, exit, and use-of-system services.
Operating state	The operating state of the power system is defined as satisfactory, secure or reliable, as described below. The power system is in a **satisfactory** operating state when: • it is operating within its technical limits (i.e. frequency, voltage, current etc are within the relevant standards and ratings) • the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment. The power system is in a **secure** operating state when: • it is in a satisfactory operating state • it will return to a satisfactory operating state following a single credible contingency event. The power system is in a **reliable** operating state when: • AEMO has not disconnected, and does not expect to disconnect, any points of load connection under NER clause 4.8.9 •

	• no load shedding is occurring or expected to occur anywhere on the power system under NER clause 4.8.9 • in AEMO's reasonable opinion the levels of short term and medium term capacity reserves available to the power system are at least equal to the required levels determined in accordance with the power system security and reliability standards.
Participant	An entity that participates in the national electricity market.
Plant capability	The maximum MW output which an item of electrical equipment is capable of achieving for a given period.
Power system reliability	The measure of the power system's ability to supply adequate power to satisfy demand, allowing for unplanned losses of generation capacity.
Power system security	The safe scheduling, operation and control of the power system on a continuous basis.
Probability of exceedance (POE)	POE relates to the weather/temperature dependence of the maximum demand in a region. A detailed description is given in the AEMO ESOO.
Reliable operating state	Refer to operating state.
Reliability of supply	The likelihood of having sufficient capacity (generation or demand-side response) to meet demand (the consumer load).
Reliability standard	The Reliability Panel's current standard for reliability is that there should be sufficient generation and bulk transmission capacity so that the maximum expected unserved energy is 0.002 per cent.
Reserve	The amount of supply (including available generation capability, demand side participation and interconnector capability) in excess of the demand forecast for a particular period.
Reserve margin	The difference between reserve and the projected demand for electricity, where: Reserve margin = (generation capability + interconnection reserve sharing) – peak

	demand + demand-side participation.
System average interruption duration index (SAIDI)	The sum of the duration of each sustained customer interruption (in minutes), divided by the total number of distribution customers. SAIDI excludes momentary interruptions (one minute or less duration).
System average interruption frequency index (SAIFI)	The total number of sustained customer interruptions, divided by the total number of distribution customers. SAIFI excludes momentary interruptions (one minute or less duration).
Satisfactory operating state	Refer to operating state.
Scheduled load	A market load which has been classified by AEMO as a scheduled load at the market customer's request. A market customer may submit dispatch bids in relation to scheduled loads.
Secure operating state	Refer to operating state.
Separation event	In the context of frequency control ancillary services, this describes the electrical separation of one or more NEM regions from the others, thereby preventing frequency control ancillary services being transferred from one region to another.
Short term projected assessment of system adequacy (ST PASA) (also see MT PASA)	The PASA in respect of the period from two days after the current trading day to the end of the seventh day after the current trading day inclusive in respect of each trading interval in that period.
Spot market	Wholesale trading in electricity is conducted as a spot market. The spot market allows instantaneous matching of supply against demand. The spot market trades from an electricity pool, and is effectively a set of rules and procedures (not a physical location) managed by AEMO (in conjunction with market participants and regulatory agencies) that are set out in the NER.
Supply-demand balance	A calculation of the reserve margin for a given set of demand conditions, which is used to minimise reserve deficits by making use of available interconnector capabilities.

Technical envelope	The power system's technical boundary limits for achieving and maintaining a secure operating state for a given demand and power system scenario.
Transmission network	The high-voltage transmission assets that transport electricity between generators and distribution networks. Transmission networks do not include connection assets, which form part of a transmission system.
Transmission network service provider (TNSP)	An entity that owns operates and/or controls a transmission network.
Unserved energy (USE)	The amount of energy that is required (or demanded) by consumers but which is not supplied due to a shortage of generation or interconnection capacity. Unserved energy does not include interruptions to consumer supply that are caused by outages of local transmission or distribution elements that do not significantly impact the ability to transfer power into a region.