RELIABILITY
PANEL AEMC

REVIEW

Reliability Panel AEMC

ANNUAL MARKET PERFORMANCE REVIEW 2017

Final report

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About the Reliability Panel

The Panel is a specialist body within the Australian Energy Market Commission (AEMC) and 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. The Panel's responsibilities are specified in section 38 of the National Electricity Law.

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Foreword

I am pleased to present this final report setting out the findings of the Reliability Panel's annual review of market performance.

The Panel has reviewed the performance of the national electricity market (NEM) in terms of reliability, security and safety over the 2016/17 period, in accordance with the requirements of the National Electricity Rules. 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 the likelihood of consumers being supplied and at the wholesale level is primarily driven by market investment. We have considered both historic trends and some projections of the security and reliability of the NEM.

In 2016/17, the security performance of the NEM has been mixed. In 2016/17 there were 11 instances of the system being operated outside its secure limits for greater than 30 minutes. Under the National Electricity Rules (Rules) AEMO is required 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 thirty minutes. While the frequency operating standard was met in the mainland it was not met in Tasmania for seven months of the reporting year.

In 2016/17, at a wholesale level, 0.00036 per cent unserved energy from events which the rules define as reliability events was recorded in South Australia. This is within the reliability standard (an expectation that no more than 0.002 per cent of demand for energy will be unmet in any region of the NEM). At a wholesale level, there was no other unserved energy recorded due to reliability events for any other region in the NEM. While the NEM has performed well over the last decade in terms of reliability, projections show that some unserved energy, within the reliability standard, is forecast over the medium term (2018/19 to 2026/27).

The Panel also notes there are a number of significant changes ongoing in the NEM, with implications for reliability and security.

There were some major security events witnessed in 2016/17, chiefly, the South Australian black system event which occurred on 28 September 2016. This incident saw a total loss of supply to the region, close to 850,000 customers. It is estimated that South Australian businesses suffered costs of $450 million as result of the blackout. This incident demonstrated both the importance and difficulty in maintaining system security in a changing environment.

The reliability load shedding event that occurred in South Australia on 8 February 2017, featured extreme temperatures that led to high demand conditions and coincided with factors including outages of thermal generation and inaccurate forecasts.

In addition there is ongoing retirement of conventional thermal generation. In March 2017, 1600MW of brown coal generation was withdrawn from the NEM with the closure of the Hazelwood Power Station. This trend is coupled with continuing entry of large volumes of new generation technologies, particularly intermittent, renewable generation.

In the context of these challenges, the Panel acknowledges the significant body of work underway that is currently considering how to maintain the resilience of the NEM.

This includes the Energy Security Board's (ESB) *National Energy Guarantee*, the Panel's *Reliability standard and settings review*, the Australian Energy Market Commission's (AEMC) *Reliability frameworks review*, the AEMC's *Frequency control frameworks review* and the AEMC's *Generator technical performance standards* rule change. The frameworks requiring Transmission Network Service Providers (TNSPs) to maintain minimum levels of inertia and system strength will also commence 1 July 2018. These frameworks arise from the Commission’s *Managing the rate of change of power system frequency* and *Managing power system fault levels* final rules. AEMO’s first power system frequency risk review, required by the *National Electricity Amendment (Emergency frequency control schemes)* rule will also be complete by April 2018.

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 complete d without the assistance of AEMO, the Australian Energy Regulator, 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.

Brian Spalding, Chairman, AEMC Reliability Panel,

Commissioner, AEMC

Concise report

This final report sets out the findings of the Reliability Panel's 2017 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 2016 to 30 June 2017, the 2017 AMPR includes observations and commentary on the security, reliability and safety performance of the power system.

This concise report is structured as follows:

- Key concepts: security, reliability and safety are the three main concepts considered by the Panel when undertaking the AMPR.
- Market trends: the key trends in generation, interconnection and demand.
- Security review: an overview of security outcomes and emerging trends in the NEM.
- Reliability review: an overview of reliability outcomes and forecasts 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.

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 concepts

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

- ***Security:*** Security relates to the maintenance of the power system within specific technical operational limits, including specific frequency and voltage limits. AEMO (the system operator) operationally manages security. This is done through a variety of measures such as constraints applied in the dispatch of generation, directing participants or instructing load shedding.

  The power system is defined to be in a secure operating state if:

  — the power system is in a satisfactory operating state[1]

  — the power system will return to a satisfactory operating state following the occurrence of any credible contingency event in accordance with the power system security standards.[2]

1 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.

2 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. For example, a credible contingency could include the failure of a single generating unit or a single

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 thirty minutes.

- ***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.[3]

  In relation to the Panel's review, reliability is considered in terms of unserved energy which 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. The current reliability standard is therefore 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.

  The current reliability standard is that no more than 0.002 per cent of demand in a region should be at risk of not being met.[4] 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 range of future scenarios, weighted for probability.

  It is important to note that there are a number of other, non-reliability related circumstances and events that may cause an interruption to consumer supply. These include:

  — distribution network outages

  — transmission network outages, in the non-bulk transmission sections of the transmission network (i.e., parts of the transmission network other than interconnectors)

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major item of transmission plant. The power system security standards are defined in Chapter 10 of the rules.

3 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.

4 Taking New South Wales as an example, when translated the 0.002 per cent reliability standard means that no more than 1.36GWh should be at risk of not being supplied for 2016/17. (This is based on the *2017 Electricity statement of opportunities'* neutral forecast for demand in New South Wales of 67,958.29GWh). This would equate to roughly 170,000 customers in New South Wales interrupted for four hours (based on an estimate of 2kW of load per customer and assuming the outage might persist for four hours).

— imbalances in generation and demand triggered by shortages in generation capacity due to a non-credible contingency.[5]

- *Safety:* While the general safety in the NEM is an important consideration under the National Electricity Law (NEL), there is no single national safety regulator for electricity. Instead, jurisdictions have specific provisions that explicitly refer to the safety duties of networks, as well as other aspects of electricity systems such as metering and batteries.[6] The Panel considers that the power system is safe when it is maintained and is operating in a secure condition. However, the Panel limits its consideration of safety to maintaining power system security.

Market Trends

There were a number of key market trends in the NEM in 2016/17, including:

- withdrawal of synchronous thermal generation, particularly in Victoria[7]
- the entry of new generation capacity, mainly intermittent, large scale, non-synchronous wind and solar generation
- expansion of the capability of the Heywood interconnector between Victoria and South Australia
- significant changes in the demand side of the market, particularly in relation to residential PV and storage.

Supply side trends

There were significant changes to the generation mix in the NEM in 2016/17. The region most affected was Victoria, which experienced the withdrawal of Hazelwood Power Station (1600MW). The withdrawal of Hazelwood Power Station represented a 13 per cent decrease in the total installed generation capacity in Victoria. It also represented a 15 per cent decrease in the total installed synchronous capacity in Victoria.

The other withdrawn generator for this period was the Tamar Valley Power Station. Hydro Tasmania stopped operating the 208 MW combined cycle gas turbine in May 2017. However, ahead of the 2017/18 summer the full capacity of the unit was returned to service. Hydro Tasmania has since announced that it will withdraw the Tamar Valley Power Station after April 2018, but that the unit will be available to return to operation with less than 3 months' notice.

The generation mix as of 30 June 2017 is shown in Figure 1. This figure includes:

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5 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.

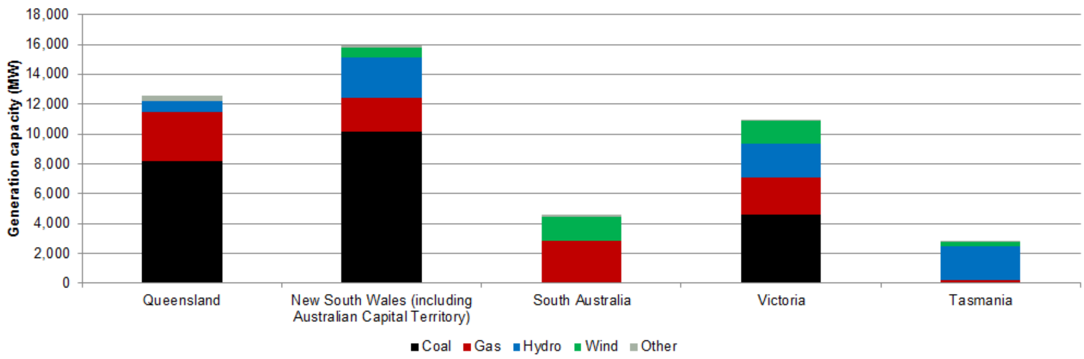
6 See section 2D(a) of the NEL.

7 Synchronous generators are large spinning units that have turbines that spin at the same speed as the frequency of the power system. Because the mechanical energy of the turbine is directly related to the frequency of the power system, they can typically provide what is known as “physical inertia”. This inertia can assist in slowing changes in power system frequency, following a major disturbance like the loss of a transmission line.

- The full capacity of Pelican Point Power Station (478MW)[8]
- The full capacity of Smithfield Power Station (176MW).[9]

Figure 1 does not include Swanbank E gas-fired power station which was returned to full operational capacity (385MW) from 1 January 2018.[10]

Figure 1 Regional breakdown of generation capacity by fuel type



Source: AEMO, *Generator information page*

It has been announced that 2064MW of generation will be withdrawn from the NEM by mid-2022. All of the generation units announced for withdrawal are thermal, synchronous units. The generators announced for withdrawal are:

- AGL has announced its intention to withdraw the Liddell Power Station (2000MW) in New South Wales in March 2022.
- Stanwell has announced its intention to withdraw the Mackay GT Power Station (34MW) in Queensland in July 2021.
- Energy Infrastructure Investments has announced its intention to withdraw the Daandine Power Station (30MW) in Queensland in June 2022.

The withdrawal of synchronous generation capacity is being offset in part by the introduction of renewable, intermittent generation capacity. In 2016/17, 441MW of new generation was commissioned. In terms of capacity, the main generation projects commissioned in 2016/17 are:

- Ararat Wind Farm (240MW) in Victoria has been in full commercial operation since April 2017.
- Hornsdale Wind Farm Stage 1 (102MW) in South Australia has been in full commercial operation since January 2017.

8 Engie reduced the capacity of the Pelican Point Power Station in South Australia by half in April 2015. From July 2017 it was returned to its full capacity

9 Visy Power Generation closed the Smithfield Power Station (176MW) at the end of July 2017. However 109MW of gas-fired capacity at Smithfield was made available for summer 2017/18. AEMO has confirmed 109MW is the re-registered capacity of the power station with the units now operating in open cycle gas turbine mode.

10 Stanwell Corporation placed the Swanbank E Power Station into cold storage in 2014. The Queensland Government, as asset shareholder, directed Stanwell to return the Swanbank E gas-fired power station to full operational capacity.

All newly committed generation in 2016/17 was also intermittent, renewable generation. A total of 1312MW of generation was committed by the end of 2016/17. In terms of capacity the main projects included:

- Bungala Solar Power Project (220MW) in South Australia.
- Hornsdale Wind Farm Stage 2 and Stage 3 (211MW) in South Australia.
- Mt Emerald Wind Farm (181MW) in Queensland.
- White Rock Wind Farm (173MW) in New South Wales.
- Clare Solar Farm (100MW) in New South Wales.

Demand side trends

A number of demand side trends continued in 2016/17.[11] Operational consumption remained flat.[12] AEMO forecasts that consumption is to remain relatively flat, declining by 1.6 per cent over the ten year period to 2026/27.[13] Key demand side trends include:

- While an increasing number of electrical appliances are being used by households this is projected to be offset by the use of more energy - efficient appliances and household energy generation from rooftop PV.
- Improved building efficiency will also reduce demand for space cooling and heating.
- From the perspective of businesses, electricity consumption is to be driven by coal seam gas (CSG) production to supply gas to liquefied natural gas (LNG) trains and the 'other' business sector as projected population and household disposable income grows.[14] CSG production projects are electricity intensive, with electricity consumed at coal fields, mainly for gas processing and compression, as well in the pumping of groundwater.[15]

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11 The term “demand” can be used in both a generic and specific sense. In this context, demand refers generically to the demand side of the market, being consumers of electricity, as opposed to the supply side of the market, being generators of electricity. However, the term can also be used in a specific sense, as a description of how electricity is used. For example, the term electricity consumption refers to the total amount of electricity used over a period of time whereas in this context, the term electricity demand is used to describe the amount of electricity used at a particular point in time.

12 Operational consumption refers to the electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units over a period of time. Operational consumption does not include rooftop solar PV output, that is operational consumption will decrease with increased rooftop PV output.

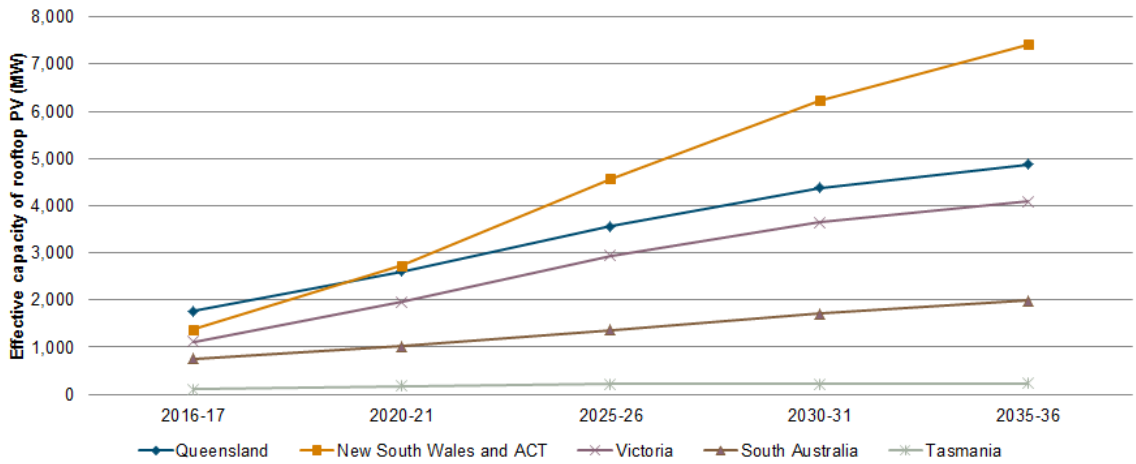
13 For the neutral demand scenario described in the *2017 Electricity statement of opportunities*.

14 The other business sector includes industries such as education, financial services, IT, infrastructure, and health and aged care.

15 In the long term increased electricity use per CSG well is expected, as more marginal fields are developed. AEMO, *Coal Seam Gas Sector Consumption*, accessed at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/Business-consumption/CSG on 8 March 2017.

Figure 2 shows installed rooftop PV capacity is forecast to continue growing and is projected to reach 18.6GW by 2035/36.[16] Strong growth in integrated PV and storage system installations is also expected to increase significantly. The total installed capacity of integrated PV and storage systems is projected to be 5.4GW.[17]

Figure 2 Installed rooftop PV capacity forecasts



Source: AEMO.

For New South Wales, Victoria and Tasmania maximum demand forecasts were generally flat. Maximum demand in Queensland is forecast to grow 6.1 per cent over the next ten years.[18] Over the same period, maximum demand in South Australia is forecast to fall by 5.6 per cent.[19] Forecast maximum operational demand is shifting to later in the day, when the contribution of rooftop PV is falling but temperatures remain high.

Over the next ten years, minimum demand levels are forecast to decrease for all regions, except Tasmania, due to the continued growth of rooftop PV.

Interconnector developments

In August 2016, the Heywood interconnector, which connects Victoria and South Australia, was upgraded to allow increased power flows between the two regions. Currently, the Heywood interconnector's transfer limit from Victoria to South Australia is set at 600MW, while the transfer limit from South Australia to Victoria is set at 500MW.[20]

16 Note this figure refers to effective capacity. Effective capacity accounts for PV panel degradation over time.

17 The 5.4GW stated here refers to the battery storage component of these systems.

18 Maximum demand in Queensland is forecast to increase due to increased cooling load and projected growth in demand by the CSG sector.

19 Maximum demand in South Australia is forecast to decrease driven by projected increases in rooftop PV, battery storage, and energy efficiency improvements.

20 The interconnector's increased maximum design limit of 650MW flow in both directions has not yet been fully released into the market due to potential transient stability issue. Prior to the upgrade the Heywood interconnector's capacity was 460MW.

In November 2016, ElectraNet released a Project Specification Consultation report as part of a RIT-T process.[21] The report provided an economic cost benefit assessment of various network and non-network solutions to assist the management of South Australia's increasing penetrations of renewable energy. The report presented five credible options, four of which were new interconnectors.[22]

On 24 November 2017, the Commonwealth and Tasmanian Governments announced they would invest up to $20 million for a business case study for a second Tasmanian interconnector.

Based on preliminary modelling completed for the *2018 Integrated system plan* AEMO recommends that:[23]

- Powerlink and TransGrid initiate a RIT-T to increase transfer capacity between Queensland and New South Wales.[24]
- A joint planning study should commence in 2018 to determine the feasibility and preferred option to upgrade the Victoria to New South Wales interconnector.

In 2016/17 there were seven operating incidents in which interconnectors tripped or were operated beyond their limits such that the system was not in a secure operating state.[25]

Over the last decade South Australia has imported an increasing amount of energy, corresponding to an increase in Victoria's exports over this same period. Since 2007/08 Tasmania has been both an importer and exporter of energy on annual basis.[26]

Security

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.

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21 RIT-T refers to regulatory investment test for transmission. The rules require that a transmission network service provider undertake a RIT-T for any projects with an estimated cost of more than $6 million. The purpose of a RIT-T is to identify the transmission investment option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market, after performing cost-benefit analysis on a number of credible options..

22 The four interconnector options included: (i) central South Australia to Victoria; (ii) mid-north South Australia to New South Wales; (iii) northern South Australia to New South Wales; (iv) northern South Australia to Queensland. ElectraNet, *RIT-T: Project Specification Consultation Report*, November 2016.

23 AEMO, *Integrated System Plan Consultation*, December 2017, p. 38.

24 The AER has since accepted a proposal from Powerlink for an upgrade of QNI to be included as a contingent project in its 2017-22 regulatory control period. AER, *Final decision - Powerlink transmission determination, 2017-18 to 2021-22*, April 2017.

25 Incidents occurred on: 28 September 2016 (South Australia), 1 December 2016 (South Australia), 8 February 2017 (South Australia), 10 February 2017 (New South Wales), 3 March 2017 (South Australia), 12 March 2017 (Tasmania), 29 March 2017 (Queensland).

26 For further detail see Figure 3.15.

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 thirty 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.[27]

Maintaining the system in a secure operating state places tighter restrictions on operation than when it is in a satisfactory state. When 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 consumer load shedding.

In terms of the security of the NEM in 2016/17, the Panel notes:

- There were 11 instances of the power system being operated outside its secure limits for greater than 30 minutes.[28] Four of these instances were due to secure voltage limits being exceeded.
- There were three occasions where under frequency load shedding schemes were triggered.[29]
- The frequency operating standard was met for the mainland.[30] However, the frequency operating standard was not met for Tasmania for seven months of the 2016/17 financial year.[31] Figure 3 shows the percentage of time the frequency

27 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.

28 Supply interruptions were experienced by consumers for four of these instances. The Panel notes the number of times the system has exceeded secure operating limits has increased over the past three years. The system was not in a secure operating state for greater than 30 minutes on four occasions in 2014/15 and seven occasions in 2015/16.

29 In South Australia on 1 December 2016 in South Australia and in Tasmania on 20 December 2016 and 12 March 2017.

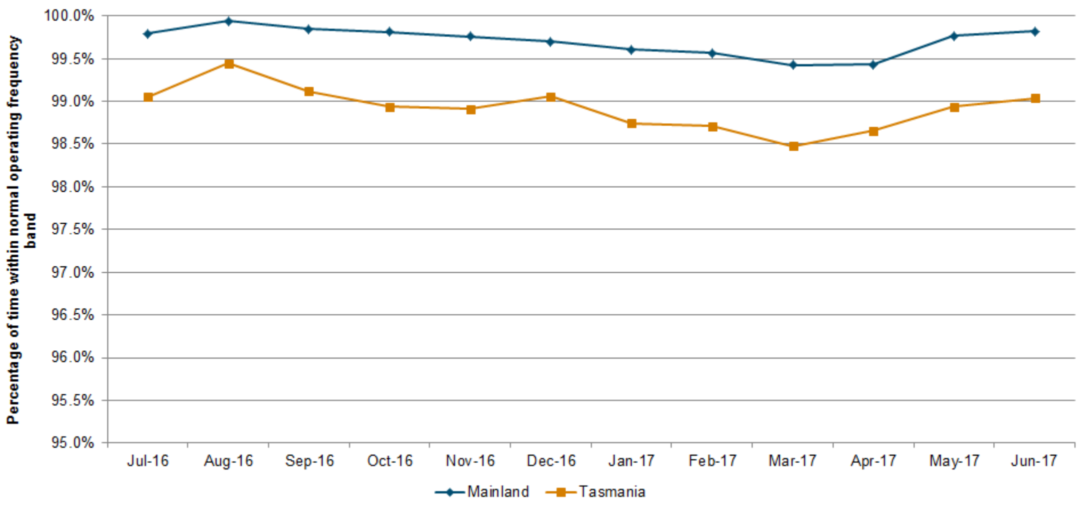
30 The frequency operating standard is determined by the Reliability Panel and sets out the frequency bands within which AEMO must operate the system. The frequency operating standard is currently under review. For more information see: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard

31 These months were October 2016, November 2016, January 2017, February 2017, March 2017, April 2017 and May 2017. AEMO investigated the gradual decline in frequency performance and identified that times of prolonged frequency deviations coincided with a large portion of regulation FCAS enabled in Tasmania. During these times, the automatic generation control (AGC) system at AEMO was not able to dispatch the full enablement of regulation FCAS in Tasmania due to its detuned configuration at the time..

was within the normal operating frequency band for the mainland and Tasmania.[32]

- Over the past three years, the number of times the normal operating frequency band has been exceeded in the mainland and Tasmania has increased. • System restart ancillary services were called upon by AEMO on 28 September 2016 to restore supply in South Australia following the black system event.[33]
- There were eight instances where AEMO issued directions to maintain the power system in a secure operating state.[34] By comparison, two directions were issued to maintain the system in a reliable operating state.

Figure 3 Percentage of time within normal operating frequency band



Source: AEMO

In the context of falling levels of synchronous generation and changes in the way generating units are being operated, a number of system security issues have arisen. These issues include, but are not limited to the following:

- ***Degradation of frequency performance during normal operation:*** According to analysis the root cause of the long term degradation of frequency performance is a reduction in the level of primary frequency control provided during normal system operation. Primary frequency control provides the initial response to frequency disturbances.

  DIgSILENT has attributed reduced primary frequency control to a decline in governor response provided by generators within the normal operating frequency band.[35] There are a number of risks associated with this reduction in

32 When the system is operating normally (i.e. with no regions separated or being restored from a contingency event) the normal operating frequency band is the range of frequency from 49.85Hz to 50.15Hz.

33 This was the first time system restart ancillary services have been called upon since the start of the NEM.

34 Direction events occurred on: 9 and 11 October 2016 in South Australia; 1 December 2016 in Victoria and South Australia; 28 and 29 March 2017 in Queensland; 25 and 26 April 2017 South Australia.

35 DIgSILENT, *Review of frequency control performance in the NEM under normal operating conditions, final report*, 19 September 2017.

primary frequency control and associated degradation of the frequency distribution. These risks include:

- an increase in the rate of wear and tear on mechanical generating equipment for those generators that respond to frequency changes.
- a decrease in the operational efficiency of mechanical generating equipment, especially where a generator continues to be responsive to frequency
- an increase in potential for frequency oscillations
- difficulty in AEMO meeting the performance standards set out in the frequency operating standard
- potential for increased rate of change of frequency and maximum deviation in response to contingency events
- an increase in the variability of interconnector flow on network interconnectors following contingency events.
- an increase in FCAS costs as the quantities and utilisation of existing FCAS products increase to control power system frequency.

Issues related to primary frequency control are key focus area of the AEMC's *Frequency control frameworks review.*[36]

- ***Decreases in available system inertia, resulting in increased challenges to maintain system frequency following disturbances:*** A certain level of system inertia is necessary to maintain the rate of change of frequency to manageable levels.[37] Over the last few years there has been a decreasing level of system inertia due to the withdrawal of synchronous thermal generation and increased penetration of non-synchronous generation. The rate of change of frequency following a sudden change in the supply-demand balance is related to the level of inertia in the system and the size of the change. If the rate of change of frequency is sufficiently large, it can result in the failure of load or generation.[38]

  Under the AEMC's *Managing the rate of change of power system frequency* final rule, TNSPs will be required to procure the minimum levels of inertia to maintain the system in a secure operating state.[39]

- ***Declining system strength:*** System strength is a quantity inherent to any power system and is typically enhanced by synchronous generation. It relates to the

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36 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review

37 This is the case in the NEM currently. Future technologies may be able to substitute for inertia. Inertia is naturally provided by conventional electricity generators, operating with large spinning turbines and alternators that are synchronised to the frequency of the grid. Non-synchronous units often do not provide the same kind of inertial response. This trend is likely to continue as the fleet of coal fired generation ages and there is a large increase in the development of solar farms and wind farms and continued strong uptake of rooftop PV.

38 This may in turn exacerbate the rate of change of frequency. If the rate of change of frequency is large enough, emergency schemes may not be able to prevent a broader system collapse.

39 See: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

extent of the decrease in voltage in the power system following a fault. The supportive characteristics of synchronous generation, as related to system strength, are not typically provided by power electronic converter-connected, non-synchronous generation technologies

Declining system strength can lead to localised issues and can also have broader power system impacts. Three potential challenges for power system security are:[40]

1. the possible reduced effectiveness of some types of network and generating systems' protection functions
2. power electronic converter-interfaced devices such as wind turbines and solar inverters require a minimum level of system strength to operate in a stable and reliable condition.[41] Reduced system strength could therefore impact on their ability to ride through faults on the system
3. voltage control in response to small and large system disturbances is also affected by system strength, with weaker systems are more susceptible to voltage instability or collapse.

The issue of declining system strength has been addressed with the new framework established by the AEMC's *Managing power system fault levels* rule.[42] Under this rule, TNSPs will be required to procure the minimum levels of system strength to maintain the system in a secure operating state.

In July 2017, AEMO introduced a new system strength constraint in South Australia. The new constraint initially restricted non-synchronous (wind) generation to 1200MW when only a minimum system strength requirement was met. In December 2017, AEMO announced this limit had been increased from 1200MW to 1295MW.[43]

There were a number of major system security incidents that occurred in 2016/17. Three of the four system security events described below resulted in load shedding.

- ***28 September 2016, South Australia:*** A black system event occurred in South Australia in which the entire region, some 850,000 customers, lost electricity supply. Briefly, the incident involved:[44]
  - Tornadoes damaged transmission infrastructure causing faults on the network. These faults led to a reduction in wind farm output, triggered by the specific protection settings of a number of windfarms, culminating in the trip of the Heywood interconnector and the separation of South Australia from the NEM.

40 AEMO, *Future power system security program progress report,* August 2016, p. 45

41 Fault levels are directly related to power system strength. A low strength system will have low fault levels.

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

43 AEMO, *Transfer limit advice – South Australian system strength*, December 2017, p. 5.

44 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017

— Without any substantial load shedding following separation, the remaining generation was much less than the connected load and unable to maintain the islanded system frequency. As a result, all supply to the region was lost at 4.18pm and the region was considered to be in a "black system" condition.

— About 40 per cent of the load in South Australia capable of being restored had been restored by 8.30 pm, and 80 to 90 per cent had been restored by midnight. The restoration process was complicated by the failure of both South Australian SRAS generators.

— The black system event had significant economic and social consequences. Estimates of impacts on the South Australian economy suggest that businesses suffered costs of $450 million as a result of the black system.[45]

- ***1 December 2017, Victoria and South Australia:*** A fault on the Moorabool to Tarrone 500 kV transmission line in Victoria resulted in the loss of the Heywood interconnection between South Australia and Victoria. At the time of the incident:[46]

  — South Australia was only connected to the Victorian network via one 500kV Heywood Interconnector circuit, because the second circuit, which is normally connected, was out of service due to planned equipment maintenance arranged by AusNet Services.

  — A second planned outage, meant that the load to Alcoa Portland aluminium smelter was supplied via a single connection.

  — The disconnection of the Moorabool–Tarrone 500kV transmission line resulted in:

    o the operation of South Australia Power Networks' under frequency load shedding scheme, disconnecting approximately 190MW of load in South Australia (for 38 minutes).[47]

    o the operation of the Emergency APD Potline Tripping Scheme, disconnecting all of the load at the Portland smelter (473MW, for 3 hours and 23 minutes).

- ***10 February 2017, New South Wales:*** A multiple contingency event occurred with all four Colongra units (667MW in total) failing to start when required.[48] The following were some of the characteristics of this event:

45 Parliament of South Australia, *Report of the select committee on the statewide electricity blackout and subsequent power outages*, 28 November 2017, p. 12.

46 AEMO, *Final report, South Australia Separation Event, 1 December 2016*, 28 February 2017.

47 There was also an additional load reduction of 40MW that was not associated with the operation of the under frequency load shedding scheme. ElectraNet have advised AEMO that this load reduction occurred at Prominent Hill in the northern part of the state. Neither ElectraNet nor AEMO are aware of any load shedding scheme (frequency or voltage) in this area.

48 A multiple contingency event refers to "either a contingency event other than a credible contingency event, a sequence of credible contingency events within a period of 5 minutes, or a further separation event in an island." Reliability Panel, *Frequency operating standard*, November 2017, p. 10.

- The supply-demand balance was tight:[49]
    - o High temperatures had led to high demand conditions
    - o There was a forced outage of the Tallawarra Power Station (420MW) and two of Liddell's four units (over 800MW) were also unavailable
- AEMO directed TransGrid to shed a potline (290MW for 63 minutes) at the Tomago aluminium smelter to restore the power system in New South Wales to a secure operating state.

- ***3 March 2017, South Australia:*** A non-credible contingency event occurred. The incident:[50]
    - Involved a series of faults at ElectraNet's Torrens Island 275kV switchyard resulted in the loss of approximately 610MW of generation in South Australia across five generating units.
    - Featured a 400MW drop in demand in South Australia. It is important to note AEMO did not instruct load shedding, and there was no operation of the under frequency load shedding scheme.
    - Almost resulted in the trip of the Heywood interconnector, and a repeat of the black system event that occurred on 28 September 2016 - this was averted as voltage levels at the South East substation were higher for this event than on 28 September 2016.

Reliability

In 2016/17, at a wholesale level, unserved energy of 0.00036 per cent from events which the rules define as reliability events was recorded in South Australia. This is within the reliability standard, which is measured at 0.002 per cent of expected demand being unmet.

At a wholesale level, no unserved energy occurred in any other NEM region.[51] It is important to note that the absence of unserved energy does not mean load shedding did not occur. Rather, it means that any load shedding that occurred was not related to the level of market driven investment and events defined as reliability events in the rules. Figure 4 shows unserved energy last occurred in the NEM in 2008/09.[52]

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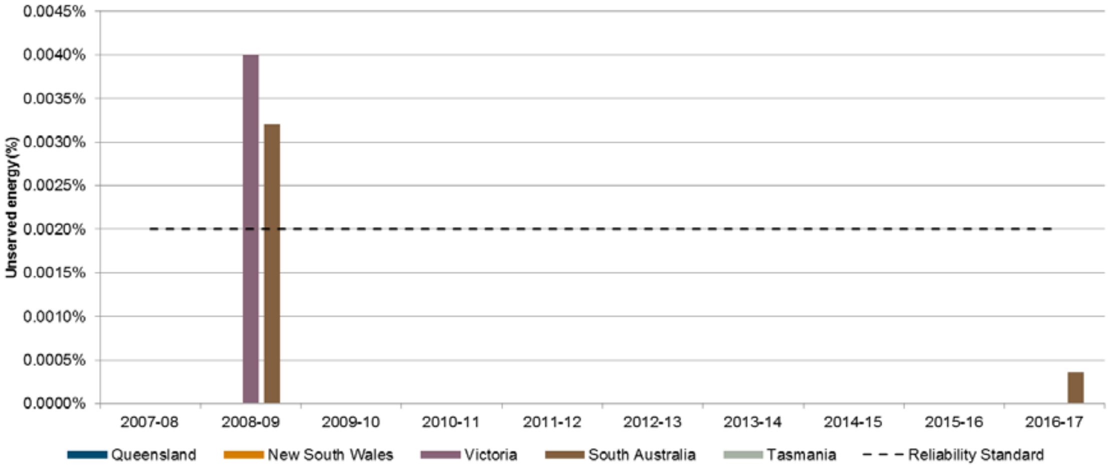
49 AEMO, *System event report, New South Wales, 10 February 2017,* 22 February 2017.

50 AEMO, *Fault at Torrens Island switchyard and loss of multiple generating units, 3 March 2017,* 10 March 2017.

51 The Panel notes that the following events did not satisfy the rules definition of unserved energy (clause 3.9.3C) and have been excluded by AEMO from unserved energy calculations: (i) 28 September 2016, South Australian black system event; (ii) 1st December 2016, Separation of South Australia, loss of Alcoa Portland supply, the operation of under frequency load shedding in South Australia and direction issued to ElectraNet to reduce load at BHP Billiton's Olympic Dam site by 45MW reduce requirement for fast lower frequency control ancillary service (L6 FCAS); (iii) 10 February 2017, load reduction at Tomago smelter in New South Wales; and (iv) the trip of Basslink and loss of 383MW of industrial load due to under frequency load shedding on 12 March 2017.

52 Unserved energy occurred in Victoria and South Australia during 29 and 30 January 2009 as extreme temperatures gave rise to very high demand. There were also short notice reductions in the availability of Basslink and progressive reductions in the availability of a number of Victorian

Figure 4 Unserved energy in the NEM



Source: AEMO

At a wholesale level, there was one reliability incident that occurred in 2016/17, where supply to consumers was interrupted and unserved energy was recorded.

- ***8 February 2017, South Australia:*** High temperatures contributed to high demand conditions. At approximately 6:00pm: demand was higher than forecast, wind generation was lower than forecast, and thermal generation capacity was reduced due to forced outages. At this time, Engie, the operator of Pelican Point Power Station, notified AEMO that 165MW of capacity was unavailable. Engie advised AEMO of a start-up time for Pelican Point which would not have enabled AEMO to meet the system security requirements under the rules. Load shedding (100MW for 27 minutes) was then implemented by AEMO to restore system security.[53]

Figure 5 shows the interruptions of supply arising from incidents involving reliability, security, transmission networks and distribution networks from 2007/08 to 2015/16. The Panel notes that interruptions to consumer supply relating to the reliability of generators and interconnectors, that is the reliability of the wholesale market, have historically represented a very small amount of all supply interruptions experienced by customers. Over the period, only about 0.24 per cent of total supply interruptions (in terms of GWh) were the result of reliability events (brown area of chart). Security events also represented a small portion (grey area) of all supply interruptions, 1.61 per cent.

Estimates show that the distribution network is responsible for about 97 per cent of supply interruptions (blue area of chart). The distribution network represents the largest infrastructure in the electricity supply chain, with many possible points of failure. Standards relating to distribution networks are set by jurisdictions through various regulatory instruments.[54] Distribution and transmission outages tend to be spread over the year (though higher rates of outages occur at times of peak demand)

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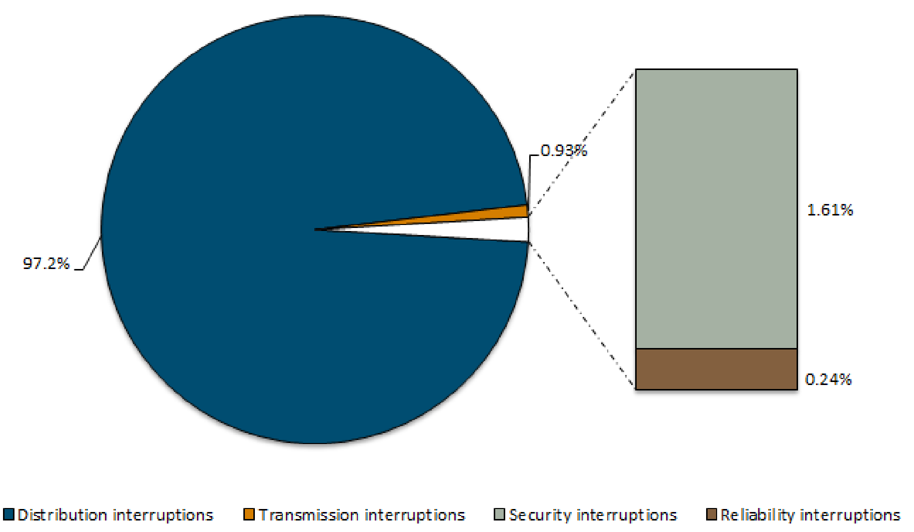
generators at short notice on both days. AEMC Reliability Panel, *Annual market performance review 2008-09, final report*, December 2009, p. 5.

53 The summary of this event is based on AEMO's incident report. AEMO, *System event report South Australia*, 8 February 2017, 15 February 2017.

54 See appendix B for more information

whereas wholesale reliability issues almost always occur at times of peak stress on the system when demand is high due to extreme weather.

Figure 5 Sources of supply interruptions in the NEM: 2007/08 to 2015/16



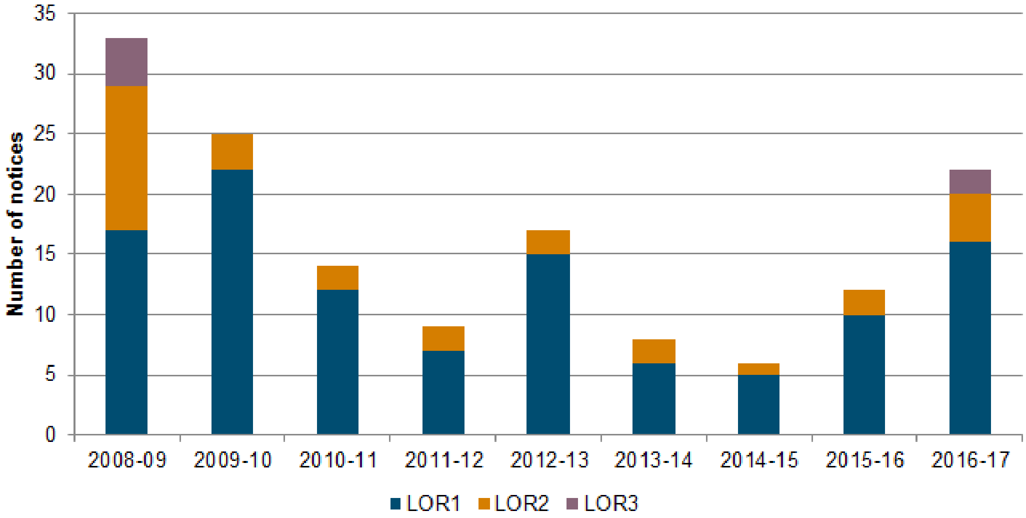
Source: AEMC analysis and estimates based on publicly available information from: AEMO's extreme weather event and incident reports and the AER's RIN economic benchmarking spreadsheets.

Lack of reserve notices are published by AEMO and indicate to the market potential shortages in spare capacity in generation. AEMO also publishes forecast lack of reserve notices when a lack of reserve is forecast in the short term.

Figure 6 shows that in 2016/17, there were 22 lack of reserve notices issued. This is the highest number of lack of reserve notices since 2009/10. Changing reserve levels may be relevant to the risk of unserved energy in a region. A narrower reserve margin may indicate that there is a greater risk of demand outstripping supply, which could in turn potentially result in unserved energy.[55]

55 The Panel acknowledges that unserved energy can occur under a number of circumstances and the increase in lack of reserve notices in 2016/17 should be taken only as a general indicator; it is not sufficient in itself to suggest that reliability in the NEM, or in any of the regions, has materially worsened.

Figure 6 **Lack of reserve conditions in the NEM**[56]



Source: AEMO

Reliability in the NEM is based around market-driven investment, retirement and operational decisions. However, AEMO is provided with various powers to intervene in the market to address potential shortfalls of reserves. AEMO has the power to either issue directions or instructions to market participants as a last resort measure, or to contract for the provision of reserves through the Reliability and emergency reserve trader (RERT) mechanism, in order to maintain power system security and reliability.[57]

- During 2016/17 two directions to market participants were issued to maintain the system in a reliable operating state.[58] As noted earlier, by comparison, eight directions to market participants were issued to maintain the system in a secure operating state.
- In 2016/17 no reserve contracts were entered into under the RERT.[59]

Two projections of unserved energy at a wholesale level have been considered by the Panel, sourced from AEMO's 2017 *Electricity statement of opportunities* (ESOO) and Ernst

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56 LOR1 means that two successive credible contingencies, such as the loss of the two largest generating units, could result in there being insufficient supply to meet demand. LOR2 means that a credible contingency, such as the loss of the largest generating unit, could result in there being insufficient supply to meet demand. LOR3 means that there is insufficient supply to meet demand. An actual LOR3 represents load shedding.
This chart uses the history of market notices of LORs being issued. The count does not exactly match the number of times LOR conditions have existed, but it shows the trend.

57 The RERT is an existing mechanism in the NEM which allows AEMO to contract for reserves (generation or demand-side capacity that is not otherwise being traded in the market), that it can use in the event that it projects that the market will not meet the reliability standard and, where practicable, to maintain power system security.

58 On 9 February 2017 in South Australia, AEMO issued a direction to ENGIE to synchronise and dispatch Pelican Point unit GT12 to minimum load. Pelican Point unit GT12 was again the subject of a direction on 1 March 2017.

59 Reserve contracts were entered into under the RERT for summer 2017/18. The RERT was activated twice in Victoria, on 30 November 2017 and 19 January 2018, to maintain the power system in a reliable operating state.

& Young's (EY) modelling for the Panel's 2018 *Reliability standard and settings review*. The Panel notes that forecasting electricity supply and demand is a complex process. The two sources of unserved energy projections described above differ in a number of ways including their overall purpose, modelling approach, input data, assumptions, and scenarios and sensitivities tested. These have in turn contributed to some differences in terms of the results presented in the two projections.

The key difference is that these two models project different amounts of unserved energy, with AEMO forecasting significantly more unserved energy than EY's projections. However, noting the differences between the two models, the Panel considers that these different projections have value in that they provide a broad view of potential future outcomes in the NEM.

In addition to the different modelling rationales (and accompanying assumptions and sensitivities), EY notes that the majority of the differences between EY's and AEMO's unserved energy forecasts are due to the following factors:[60]

- EY's half-hourly modelling of wind, solar and rooftop PV uses some different assumptions to AEMO. In particular EY uses different data sets that describe the characteristics of wind generation in different regions. This difference in wind resource data means AEMO and EY have different wind generation profiles.
- EY assumes a much greater contribution to peak demand from behind-the-meter storage, which results in lower peaks in the demand to be met by scheduled generators in the NEM, compared to AEMO.
- EY's dispatch modelling software differs from AEMO's and as a result, some aspects of the modelling approach are not the same. This factor was the smallest driver of difference between unserved energy projections.

Figure 7 presents AEMO's ESOO forecasts of unserved energy to 2026-27. Key insights from the 2017 ESOO include:[61]

- The highest forecast unserved energy risk in the 10-year outlook is in 2017–18 in South Australia (0.0015 per cent) and Victoria (0.0017 per cent).
- From 2018–19 to 2021–22, progressively decreasing levels of potential unserved energy conditions are observed over the next four summers, due to increasing renewable generation.

60 EY determined these factors from modelling work which will be published in April 2018 and accompany the release of the Panel's final report for the *Reliability standard and settings review 2018.* This modelling work involved EY replicating AEMO's ESOO "dispersed renewables" generation development plan in the EY model. The installed capacity and other assumptions were aligned to the ESOO modelling in order to isolate the reason(s) for the different unserved energy outcomes in EY's and AEMO's modelling. EY then conducted additional sensitivities to that scenario, introducing EY's data sets one by one to isolate the contributions to the unserved energy differential between the ESOO and EY's base scenario for the *Reliability standard and settings review*. EY focused on 2022-23, the year following the assumed retirement of the Liddell power station.

61 The unserved energy outcomes quoted here are based on the three main scenarios (Committed and existing generators, Concentrated renewables and Dispersed renewables) and do not include the high demand sensitivity.

- The potential for unserved energy is projected to then increase in New South Wales (peaking at 0.0014 per cent in 2024/25) and Victoria after Liddell Power Station closes (announced as 2022).

Figure 7 AEMO's unserved energy projections[62]

Source: Charts prepared using data contained in AEMO's ESOO results spreadsheets[63]

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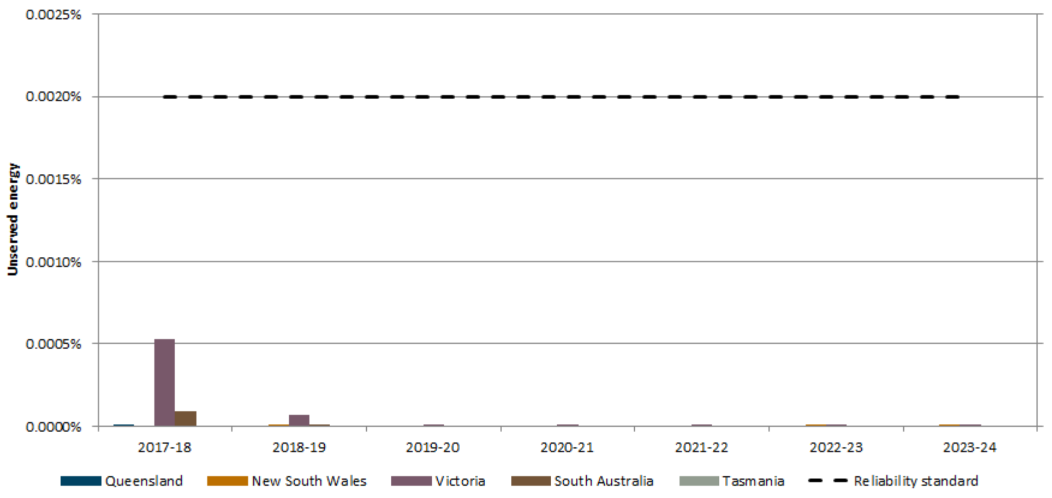
62 The *committed capacity scenario* incorporates all existing generation in the NEM and new generation that meet AEMO's commitment criteria. The *concentrated renewables scenario* assumes potential additional development after 2020 is geographically concentrated particularly in Victoria, driven by the Victorian Renewable Energy Target (VRET). The *dispersed renewables scenario* includes the LRET (as with the concentrated renewables scenario), but further assumes any additional renewable capacity incentivised from 2021 onwards is driven through nationally set (or at least co-ordinated) targets, rather than state-based schemes. Additional renewable capacity is spread across the NEM regions. AEMO also considered a *high demand sensitivity*, which includes demand growth in the upper range of expectations and assumes generation was developed according to the dispersed renewables scenario. No unserved energy was projected for Queensland or Tasmania.

Figure 8 shows EY's unserved energy forecasts.[64] Under EY's base scenario model the highest unserved energy was forecast for 2017-18 in Victoria at 0.00053 per cent. The energy and peak demand forecasts published in the 2017 ESOO’s neutral scenario were adopted in the EY base scenario for electricity consumption, rooftop PV, domestic storage and electric vehicle uptake.

Figure 8 EY's unserved energy projections



Source: EY

To further test the sensitivity of the unserved energy outcomes to circumstances such as high demand or higher forced outage rates, EY ran the base scenario varying several key parameters:

- Demand – using AEMO’s most recent strong demand forecast rather than neutral demand.[65]
- Generator outage rates – using higher generator forced outage rates (significantly higher than the base assumptions for many generators).

Over the review period the level of unserved energy forecast by the base scenario model under these sensitivities remains well below the reliability standard. The highest forecast level of unserved energy under this sensitivity analysis is in New South Wales, where the impact of high demand and EY’s forced outage rates is to increase 2023-24 forecast unserved energy to approximately 0.0003 per cent. As compared with the reliability standard of 0.002 per cent, this is a level of unserved energy that is around one seventh of the standard.

The Panel notes that the above unserved energy findings are forecasts underpinned by modelling assumptions that aim to reflect the likely outlook for the national electricity market over the review period. As such, actual unserved energy outcomes will differ from forecasts. In addition, AEMO has intervention powers under the rules to address

63 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

64 EY modelled the NEM over the period 2017/18 to 2023/24.

65 AEMO’s strong demand forecast projects consumption to end 8.2 per higher by 2026–27 than the neutral scenario. AEMO, *ESOO*, September 2017, p. 14.

potential shortfalls of reserves which will tend to limit actual occurrences of unserved energy.

Safety

The Panel's assessment of the safety of the NEM is focussed on the consideration of the links between security of the power system and maintaining the system within relevant standards and technical limits. 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.[66]

Relevant policy developments

There are several projects currently underway that focus on the security of the power system:

- AEMC's *System security market frameworks review* - addressed two key emerging issues: the management of frequency and of system strength in a power system with reduced levels of synchronous generation.
- Panel's *Review of the frequency operating standard* - stage one addressed primarily technical issues and market framework changes stemming from the new *Emergency frequency control schemes* rule, with stage two to involve a broader consideration of the settings of the frequency operating standard.
- AEMC's *Emergency frequency control schemes* rule – establishes a new framework for emergency frequency control schemes and protected events to support security of supply.
- AEMC's *Managing the rate of change of power system frequency* rule - places an obligation on Transmission Network Service Providers (TNSPs) to procure minimum required levels of inertia or alternative frequency control services to meet these minimum levels.
- AEMC's *Managing power system fault levels* rule - places an obligation on TNSPs to maintain minimum levels of system strength.
- AEMC's *Frequency control frameworks review* - considers issues in relation to: primary frequency control, FCAS, distributed energy resources.
- AEMC's *Generator technical performance standards* rule - considers amending or introducing a number of access standards for connecting generators and amending the process for negotiating performance standards.

The Panel notes that there are also various projects are currently underway that relate to the reliability of the power system:

66 This is an agenda item at the meetings of the Power System Security Working Group. This group consists of TNSP control room managers and AEMO control room managers. No issues have been raised by working group representatives in relation to this agenda item for 2016/17.

- Energy Security Board's *National Energy Guarantee* - combines reliability outcomes and emissions targets to achieve a single energy price that guides investment and operation in the lowest cost resources.[67]
- AEMC's *Reliability frameworks review* - assesses items such as: key concepts of dispatchability and flexibility, forecasting and information processes, the contract market, strategic reserve, wholesale demand response and day-ahead markets.
- Panel's *Review of the reliability standard and settings 2018* – the draft report proposes to leave the reliability standard and reliability settings for the NEM unchanged for the period 1 July 2020 – 1 July 2024.
- AEMC's *Declaration of Lack of Reserve conditions* rule - introduced a more flexible way for AEMO to declare lack of reserve conditions, allowing AEMO to move from the current contingency-based deterministic approach, to one that is probabilistic.
- AEMC's *Coordination of generation and transmission review* – reports on the drivers that could impact future transmission and generation investment.
- AEMO/ARENA's demand response trial – the three year initiative is to pilot demand response projects, and encourage other market responses to provide firm capacity.

There have also been a number of recent relevant government interventions:

- Snowy2.0 - a feasibility study into the expansion of the pumped hydro-electric storage in the Snowy Mountains Scheme to increase capacity by up to 2000MW, and provide approximately 350,000MWh of energy storage.
- Tasmanian Government's *Battery of the Nation* initiative - a blueprint for how Tasmania's renewable resources are developed over coming decades, includes potential new pumped hydro storage generation capacity.
- South Australian Government's *Energy Plan* – includes a battery storage and renewable technology fund, a state owned gas power plant, an energy security target and local powers over the national market.

Consultation

One submission to the review was received from the South Australia Chamber of Mines and Energy (SACOME). The submission recommended:

> "[the] AEMC [and Panel] acknowledge the operational impacts system outage events cause and input this into official analyses with other energy market bodies, such as AER, to wholly comprehend the economic impacts of constrained markets and those with low system security."

Conclusions

There were a number of significant changes in 2016/17, which reflected various ongoing trends in the NEM.

67 Energy Security Board, *Overview of the National Energy Guarantee*, November 2017, p. 1.

One such change was the withdrawal of conventional thermal generation coupled with the continued entry of newer generation technologies particularly wind and solar photovoltaics. These changes have a number of implications for the ongoing security and reliability of the NEM.

Contributing factors to security events in 2016/17, namely the South Australian black system, include: protection settings on wind farms, lower levels of inertia resulting in high rates of change of frequency and equipment failure.

Factors that contributed to the reliability event and load shedding that occurred in 2016/17 include: outages of multiple thermal units, and inaccuracies in demand and wind generation forecasts. For this event, load shedding was exacerbated by the failure of network equipment.

In the context 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.

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

Contents

1 Introduction

This report has been prepared as part of the Reliability Panel's (the Panel) *Annual market performance review* (AMPR) of the National Electricity Market (NEM). It covers the 2016/17 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[68]
- 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.[69]

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 calendar year and at other such times as the AEMC may request. The Panel must conduct its annual review in terms of:

- reliability of the power system
- the power system security and reliability standards
- the system restart standard
- the guidelines referred to in clause 8.8.1(a)(3)[70]
- the policies and guidelines referred to in clause 8.8.1(a)(4)[71]
- the guidelines referred to in clause 8.8.1 (a)(9).[72]

68 Clause 8.8.1(a)(1) of the rules. In performing this function, clause 8.8.1 (b) 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.

69 Clause 8.8.1 (a)(5) of the rules.

70 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.

71 The policies and guidelines referred to in clause 8.8 .1 (a)(4) govern how AEMO exercises its power to enter into contracts for the provision of reserves.

72 The guidelines referred to in clause 8.8.1 (a)(9) 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.

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 2016/17. In conducting this review, the Panel has only considered publicly available information as well as information obtained directly from relevant stakeholders and market participants.[73]

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.[74]

The AEMC has requested that the Panel review the performance of the market in terms of reliability, security and safety of the power system in 2016/17. 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 2016/17 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).[75]

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73 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.

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

75 A reviewable operating incident is a term defined in 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 a clause 4.8.9 instruction 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; or any

- In particular, the Panel has provided a detailed consideration of five specific incidents in 2016/17 that it considers are particularly significant. These incidents are:
    1. load shedding in South Australia on 8 February 2017
    2. black system event in South Australia on 28 September 2016
    3. separation event and load shedding in South Australia and Victoria on 1 December 2016
    4. multiple contingency event and load shedding in New South Wales on 10 February 2017
    5. non credible contingency event in South Australia on 3 March 2017.

- **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 2016/17
    - 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 2016/17, 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:** Safety of the power system is closely linked to the security of the power system and relates primarily to the operation of assets and equipment within their technical limits. Therefore, the Panel has limited its consideration of this matter to maintaining power system security within the relevant standards and technical limits.[76]

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.

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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.

76 Safety of jurisdictional power systems is primarily administered by individual jurisdictions. As a result, the Reliability Panel has assessed safety from the perspective of operating equipment with technical limits. However, more information on individual jurisdictional considerations of safety is provided in appendix G

Milestone	Date
Project initiated	8 August 2017
Close of submissions on review's approach and issues that should be considered	19 September 2017
Close of requests for a public meeting	19 September 2017
Publication of final report	20 March 2018

1.5 Consultation

Submissions were invited on the Panel's approach to the 2017 AMPR and the issues it is to consider. The South Australia Chamber of Mines and Energy (SACOME) was the only party to make a submission.[77] SACOME's main recommendation was that:[78]

> " [the] AEMC [and Panel] acknowledge the operational impacts system outage events cause and input this into official analyses with other energy market bodies, such as AER, to wholly comprehend the economic impacts of constrained markets and those with low system security."

1.6 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 2016/17.
- **Chapter 4 - Reliability review:** an overview of the reliability performance of the NEM in 2016/17, 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 2016/17, as well as work underway addressing these issues.
- **Chapter 6 - Safety review:** a high level summary of the performance of the power system from a safety perspective.

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77 The submission is available on the 2017 AMPR project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Annual-Market-Performance-Review-2017#

78 SACOME submission, p. 3.

- **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 – Reliability assessment
  - Appendix D – Forecasts
  - Appendix E – Weather summary
  - Appendix F – Security performance
  - Appendix G – Safety framework
  - Appendix H – Pricing review
  - Appendix I – Market price cap and cumulative price threshold
  - Appendix J – Environmental and renewable energy policies
  - Appendix K – Glossary

2 Key concepts and relevant standards and guidelines

This review focuses on the reliability, security and safety performance of the power system. These concepts are discussed below, with an explanation of the relevant standards and guidelines.

The Panel has structured this report in a way that considers reliability and security separately. This reflects the differences between reliability –the ability of the wholesale market to supply energy to consumers – and security –the ability of the power system to operate effectively within specific technical constraints, and to return to a secure state following disturbances.

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.[79]

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 us to identify where further actions may be needed, in order to improve outcomes for consumers in 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.[80]

Reliability is measured in terms of unserved energy which 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.

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. [81]

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

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79 The Panel also seeks to highlight that the vast majority of actual supply interruptions experienced by consumers are not related to either reliability or large scale system security related incidents. Rather, most blackouts are due to failures in the jurisdictional distribution networks – this is discussed in section 4.4.1.

80 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.

81 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.

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 range of future scenarios, weighted for probability.

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.[82] 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.[83]

The regulatory framework for reliability in the national electricity market is primarily market based. The reliability framework consists of:

- **Market incentives:** are provided by the wholesale spot market and contract market. Revenue earned in the spot market, in conjunction with participants' contract positions, supports reliability in the short-term since it provides a financial incentive for generators to supply electricity when there is demand to meet it. To manage their exposure to the spot market, participants typically seek to enter contracts which convert uncertain future spot prices into more certain wholesale prices.
- **Market 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.
  - 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.[84]
  - Allow for sufficient investment to provide electricity to the agreed reliability standard.
- **Supplementary information:** AEMO publications provide information to the market to supplement price signals. This information helps to guide investors' expectations for the future.
- **Interventions:** 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

82 This is different from the previous standard where compliance was measured against the moving average of the unserved energy in the most recent ten financial years. The Panel made this change as a result of its review of the standard and settings in 2010. The Panel considered that it was not appropriate to assign significant meaning to individual historical outcomes or to the average of a number of outcomes over a long period of time. Rather, the reliability of the NEM should be reviewed each year to examine any incidents that have resulted in unserved energy. See AEMC Reliability Panel 2010, *Reliability Standard and Reliability Settings Review, Final Report*, 20 April 2010, Sydney.

83 Rules clause 3.9.3D.

84 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.

smallest disruption possible to the ongoing operation of the market. These intervention mechanisms include:[85]

— The Reliability and Emergency Reserve Trader (RERT) obligations - allow AEMO to contract for reserves ahead of a period where reserves are projected to be insufficient to meet the reliability standard.

— Directions or instructions that can be issued by AEMO under clause 4.8.9 of the NER to:

  (i) 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

  (ii) instruct a large energy user, such as an aluminium smelter, to temporarily disconnect its load or reduce demand.[86]

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:[87]

- 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.[88]
- 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.[89]

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

85 AEMO's intervention mechanisms are discussed in more detail in section 4.1.3

86 This only applies to large users who are registered participants. 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. Network businesses are required to shed load in accordance with schedules provided by the relevant state government.

87 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 where there might be potential shortfalls to elicit a response from market participants.

88 PASA is a programme of information collection, analysis, and disclosure of power system security and reliability of supply prospects. The Panel notes that AEMO has recently redeveloped the medium term - PASA methodology through the reliability standard and implementation guidelines.

89 Defined in clause 4.2.7 of the rules.

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 is expected to be more than remote.[90]

To assess the reliability performance of the NEM, the "bulk transmission" capacity of the NEM is taken to equate to interconnector capability.[91] Consequently, only constraints in the transmission network that affect interconnector capability are considered when assessing the availability of reserves in a region.[92]

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.[93]

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.[94] 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

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90 The Commission has recently made a rule that removes the deterministic descriptions of lack of reserve from the rules, replacing them with a single high-level description for lack of reserve and so allowing the system operator to move to a more probabilistic framework. This is discussed in more detail in section 4.4.4.

91 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.

92 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.

93 In reporting on distribution network performance the Panel has had regard to rules clause 8.8.1(b) as set out in section 1.1 of this report.

94 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.

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 2017. 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. The Panel has included a detailed description of the September 2016 South Australian black system event in chapter 5.[95]

The Panel notes that various projects have been completed and are currently underway that relate to the reliability of the power system.[96] Completed projects include:

- *Coordination of generation and transmission investment review: stage 1* undertaken by the AEMC.[97]
- *Declaration of lack of reserve conditions rule* change undertaken by the AEMC.[98]

Projects currently underway include:

- *Review of the reliability standard and settings 2018* undertaken by the Reliability Panel.[99]
- *Reliability frameworks review* undertaken by the AEMC.[100]
- *Coordination of generation and transmission investment review: stage 2* undertaken by the AEMC.[101]

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95 Additionally, the COAG Energy Council has asked the AEMC to undertake the final stage of work by the market bodies into South Australia's black system event on 28 September 2016. The AEMC review will build on work already underway by the market operator, AEMO, into technical matters in relation to the event; as well as the Australian Energy Regulator's (AER) compliance review. The AEMC report is due to be provided within six months of the completion of both AEMO's investigation report and the AER's compliance report. For more information on this review, see: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-System-Black-Event-in-South-Australi#

96 A detailed description of these projects is provided in section 4.4

97 For more information, see the *Coordination of generation and transmission investment review* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

98 For more information, see the *Declaration of lack of reserve conditions rule* project page: http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions

99 For more information see the *Review of the reliability standard and settings 2018* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018

100 For more information, see the *Reliability frameworks review* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Frameworks-Review

101 For more information, see *Coordination of generation and transmission investment review* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

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 by AEMO within specific technical 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 power system is defined to be in a secure operating state when it is in a satisfactory operating state (all equipment is operating within safe loading levels and operational limits as set out in the NER) and will revert to a satisfactory operating state following the occurrence of a single 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.

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.[102]

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
- the frequency and extent of any violation of constraint equations
- the frequency and extent of any violations of equipment ratings.

102 The Frequency operating standard is currently subject to review by the AEMC Reliability 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

The Panel notes that various projects have been completed and are currently underway that relate to the security of the power system.[103] Completed projects include:

- *System security market frameworks review* undertaken by the AEMC[104]
- *Emergency frequency control schemes and protected events* rule change undertaken by the AEMC[105]
- *Managing the rate of change of power system frequency* rule change undertaken by the AEMC[106]
- *Generating system model guidelines* rule change undertaken by the AEMC[107]
- *Inertia ancillary service market* rule change undertaken by the AEMC[108]
- *Managing power system fault levels* rule change undertaken by the AEMC.[109]

Projects currently underway include:

- the *Review of the frequency operating standards* undertaken by the Reliability Panel[110]
- the *Frequency control frameworks review* undertaken by the AEMC[111]
- the *Generator technical performance standards* rule change undertaken by the AEMC.[112]

2.3 Safety

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

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103 These projects are described in more detail in section 5.4.

104 For more information, see the *System security market frameworks review* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review

105 For more information, see the *Emergency frequency control schemes rule* project page: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

106 For more information, see the *Managing the rate of change of power system frequency rule* project page: http://www.aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque

107 For more information, see the *Generating system model guidelines rule* project page: http://www.aemc.gov.au/Rule-Changes/Generating-System-Model-Guidelines

108 For more information, see the *Inertia ancillary service market rule* project page: http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market#

109 For more information on the *Managing power system fault levels rule*, see the project page: http://www.aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels

110 For more information, see the *Review of the frequency operating standard* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard

111 For more information, see the *Frequency control frameworks review* project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review

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

transmission and distribution systems, as well as other aspects of electricity systems such as metering and batteries.[113]

There are strong linkages between maintaining power system security and operating the power system safely. For example, the transfer limits and ratings that define the secure technical envelope for the power system are set at levels that maintain safety; and safe clearances from conductors are maintained by setting the thermal rating of transmission lines at an appropriate level. Safety, therefore, is supported by operating the power system within ratings and technical limits.

In this way, maintaining security of the power system could be considered as maintaining a "safe" power system to meet the requirements for safety in a general sense.[114]

In addition to considering the safety performance of the market as defined above, 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 H.

2.4 Standards and guidelines

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:[115]

- **System 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.
- **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, nor impact on other network users. The access standards are currently subject to review, through the AEMC’s Generator technical performance standards rule change.[116]

113 See section 2D(a) of the NEL.

114 Although it is noted that some system security considerations do not directly relate to safety, for the purpose of our considerations where the power system has been maintained in a secure state it is considered to also be in a safe condition.

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

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

- **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 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.[117] Registered performance standards represent binding obligations on a generator and are part of the connection agreement between the generator and the network service provider.[118] For 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.[119]

117 Generators with capacities smaller than 5MW 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.

118 This is required under rules clause 5.3.7(b).

119 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 of the key market trends in the generation mix and bulk transfer (i.e. interconnectors) in the NEM, including new entry, withdrawals and 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.[120] These trends also have consequential impacts on the security of the NEM such as the reduction in physical inertia inherent in the system and resultant changes to the rate at which frequency may change following a disturbance.[121]

For the period 2016/17, the Panel notes the following key trends and outcomes:

- **Forecast consumption and demand:** Electricity consumption has remained flat in 2016/17 and is forecast to remain relatively flat until 2026-27.[122] Regional maximum demand levels are forecast to increase for Queensland, decrease for South Australia, and remain stable for the other regions. Regional minimum demand levels are forecast to decrease for all regions, except Tasmania, due to continued growth in rooftop PV.[123]
- **Generation withdrawals:** In 2016/17 1838MW of generation capacity was withdrawn from the NEM, all of which was synchronous generation.[124] The withdrawal of Hazelwood Power Station (1600MW) represented a 13 per cent decrease in the total installed generation capacity in Victoria.
- **New generation:** In 2016/17 441MW of generation was commissioned and 1312MW was committed. This commissioned and committed generation was mostly comprised of large scale solar and wind projects. Almost all of this generation was non-synchronous.[125]

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

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

122 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: www.aemc.com.au.

123 Minimum demand in Tasmania is forecast to remain relatively stable.

124 This includes the Tamar Valley CCGT unit (208MW) which was withdrawn in May 2017. Tamar Valley CCGT returned to service for summer 2017/18. Hydro Tasmania has advised AEMO that this unit will be withdrawn after April 2018, but is available for operation with less than 3 months' notice. AEMO, *Summer operations 2017-18*, p. 14 and AEMO, *Generator Information page*, 29 December 2017.

125 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. Non-synchronous generators are linked to the power system through power system electronics and do not provide the

- **Bulk transfer:** The Heywood interconnector, which connects South Australia and Victoria, had its capacity increased from 460MW to 650MW in August 2017. As of November 2017, the interconnector's increased maximum design limit of 650MW flow in both directions has not yet been fully released into the market. Currently its transfer limit from Victoria to South Australia is set at 600MW, while the transfer limit from South Australia to Victoria is set at 500MW.
- **Reviewable operating incidents:** In 2016/17 there were 29 incidents reviewed by AEMO.[126] In 2016/17 there were nine more incidents reviewed than in 2015/16.
- **Wholesale prices:** In 2016/17 wholesale prices have increased for all regions of the NEM, with Queensland, New South Wales and South Australia all experiencing large increases over summer.

3.1 Demand and consumption forecasts

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.[127]

3.1.1 Key trends

The key trends in electricity demand and consumption include:

- **Residential consumption:** Total residential consumption is expected to fall slightly from 2016/17 to 2021/22 and then grow moderately out to 2026/27. Increased consumption driven by households using a greater number of electrical appliances is projected to be offset by the use of more energy - efficient appliances and household energy generation from rooftop PV. Improved building efficiency will also reduce demand for space cooling and heating. The modest consumption growth that is forecast to occur after 2021/22 is driven in part by the uptake of electric vehicles.[128]
- **Business consumption:** Total business delivered consumption is forecast to be relatively flat. Over the short term (to 2021-22), forecast growth is predominantly related to increasing electricity consumption by coal seam gas (CSG) production to supply gas to liquefied natural gas (LNG) trains. Over the medium to long term AEMO projects consumption growth to be mainly driven by the 'other',

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same kind of inertia (though they may provide synthetic inertia, or fast frequency response services), or support for system strength. Two small synchronous units were commissioned in 2016/17, Grosvenor 1 (21MW) and Oaky Creek 2 (15MW). Both were waste coal mine gas plants. Synchronous generation typically provides physical inertia and fault currents.

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

127 The demand and consumption measured throughout this chapter is 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.

128 AEMO, *Residential consumption - key insights*, accessed 8 January 2018 at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/Residential.

non-industrial, business sector as projected population and household disposable income grows.[129]

- **Demand side participation:** Demand side participation by consumers is expected to increase.[130] This is projected to be driven by commercial/industrial consumers, with demand side participation controlled by retailers or specialist aggregations providing price hedging and potential ancillary services to the market. Over the longer term, residential demand side participation is also expected to increase as more households adopt smart meters and tariffs that reward changing consumption based on market conditions and new trading platforms such as peer-to-peer.
- **Rooftop PV and battery storage:** Installed rooftop PV capacity is forecast to continue growing, with battery storage installations also expected to increase significantly.
- **Maximum operational demand:** Maximum demand is forecast to:
  - increase in Queensland due to increasing cooling load and projected growth in demand by the CSG sector.
  - decrease in South Australia due to projected increases in rooftop PV, battery storage, and energy efficiency improvements.
  - remain stable for other regions.
- **Minimum operational demand:** Minimum demand is forecast to decrease for all NEM regions, except for Tasmania. Driven by increasing rooftop PV uptake:
  - The time of minimum demand is expected to move to the middle of the day for Queensland, New South Wales and Victoria. South Australia is already experiencing minimum demand in the middle of the day.
  - In South Australia, minimum demand is expected to become negative by 2026/27.[131]

3.1.2 Consumption

Figure 3.1 shows that electricity consumption in the NEM peaked in 2008/09, before declining until 2013/14. AEMO considers that this decline was due to factors including:[132]

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129 The "other" business sector includes industries such as education, financial services, IT, infrastructure, and health and aged care. AEMO, *Business consumption - key insights*, accessed 8 January 2018 at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/Business-consumption.

130 Demand side participation reflects the capability of demand side resources (customer load reductions or generation from customers' embedded generators) to reduce operational demand at times of high wholesale prices or emerging reliability issues. Demand side participation captures direct response by industrial users, and consumer response through programs run by retailers, aggregators, or network service providers.

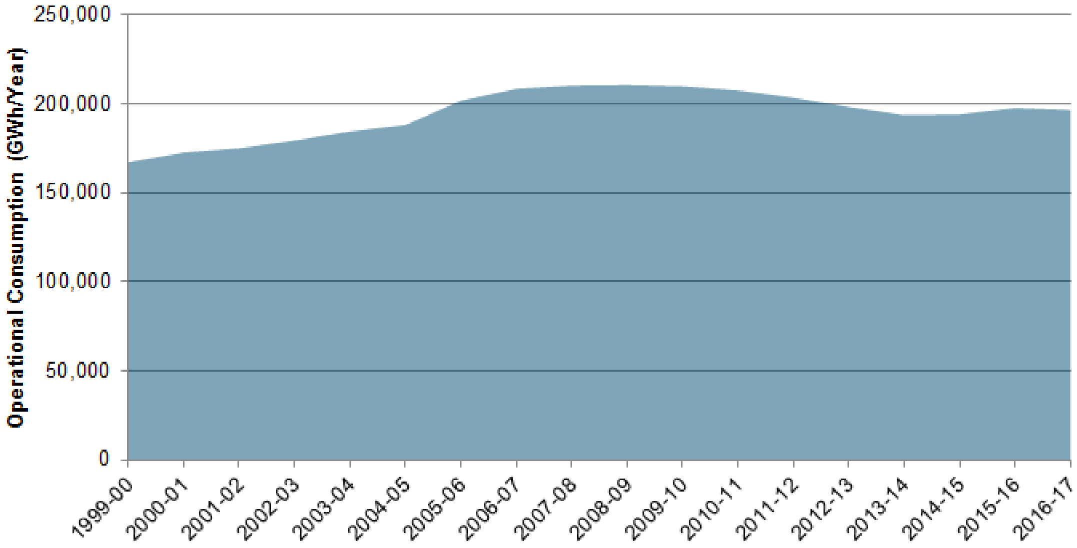
131 In South Australia, rooftop PV generation is expected to exceed customer demand in some hours.

- a rapid uptake of rooftop PV
- improvements in energy efficiency
- permanent business closures.

This fall in annual consumption flattened in 2015/16 due to consumption increases caused in part by:

- a relatively cold winter and a relatively hot summer
- the start of production of LNG exports from Queensland.

Figure 3.1 Consumption in the NEM per year[133]



AER, *Wholesale statistics*

Figure 3.2 shows that annual consumption of electricity in the NEM is forecast to remain relatively flat, (see *neutral adjusted*, grey line in the chart) declining 1.6 per cent over the ten year period to 2026/27. AEMO forecasts that consumption will decrease from 184,481GWh in 2016/17 to 181,465GWh in 2026–27[134] in the Neutral scenario. [135] This includes the following key trends:

- Total delivered residential consumption is forecast to fall from 2016/17 to 2021/22 and then grow moderately out to 2026/27. While an increasing number of electrical appliances are being used by households this is projected to be offset by the use of more energy - efficient appliances and household energy generation

132 AEMO, *2016 National Electricity Forecasting Report*, June 2016, p. 17.

133 The large increase between 2004-05 and 2005-06 is due in part to the entry of Tasmania to the NEM.

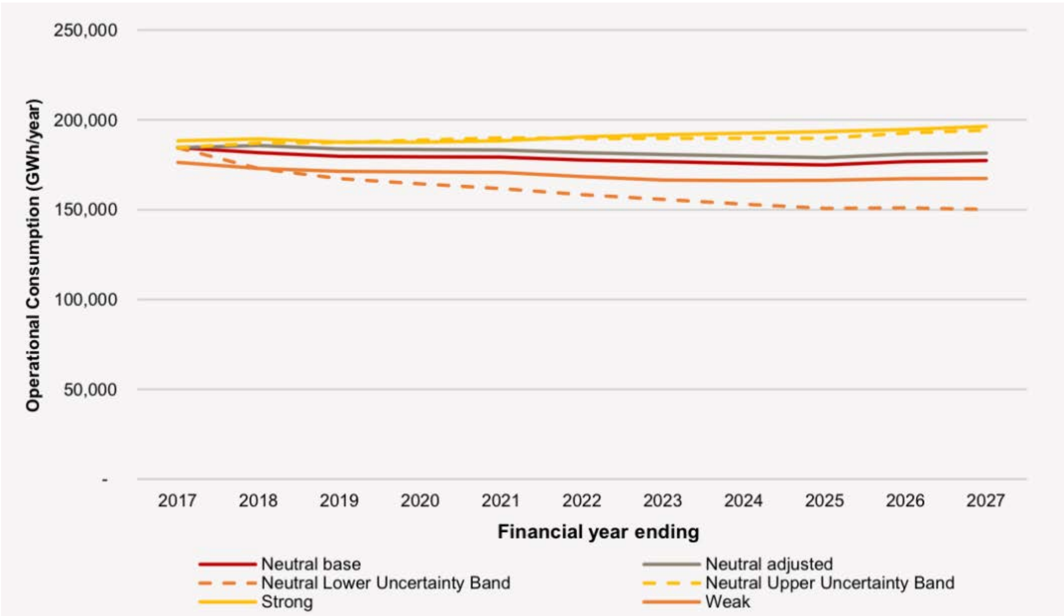
134 These figures are based on AEMO's revised forecasts in the *Electricity Statement of Opportunities*. The *2017 Electricity Statement of Opportunities* updated the demand forecasts provided in the *2017 Economic Forecasting Insights* following a review of how energy prices may impact energy demand, and how this can be best accounted for in modelling methods; the findings of interviews with large industrial consumers in each region to update price response assumptions; and a recalibration of annual consumption forecasts, to have the starting point reflect actual demand levels observed in 2016–17.

135 The Neutral scenario referenced here refers to AEMO's *2017 Electricity statement of opportunities* "neutral adjusted" forecast.

from rooftop PV. Improved building efficiency will also reduce demand for space cooling and heating. The moderate growth observed after 2021/22 is expected to be driven in part by the uptake of electric vehicles.[136]

- Total business delivered consumption is forecast to be relatively flat. Over the short term (to 2021-22), forecast growth is predominantly related to increasing electricity consumption by CSG production to supply gas to liquefied natural gas LNG trains. Over the medium to long term AEMO projects consumption growth to be mainly driven by the 'other' business sector as projected population and household disposable income grows.[137]

Figure 3.2 Forecast electricity consumption in the NEM



Source: AEMO, *2017 Electricity Statement of Opportunities*, September 2017, p. 13.

3.1.3 Maximum and minimum operational demand

Forecasts of maximum annual demand are strongly driven by weather, and occur on different days for each region of the NEM.[138] For this reason, a total maximum demand forecast is not estimated for the NEM. Forecasts are made on a region-by-region basis.[139]

136 AEMO, *Residential consumption - key insights*, accessed 8 January 2018 at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/Residential.

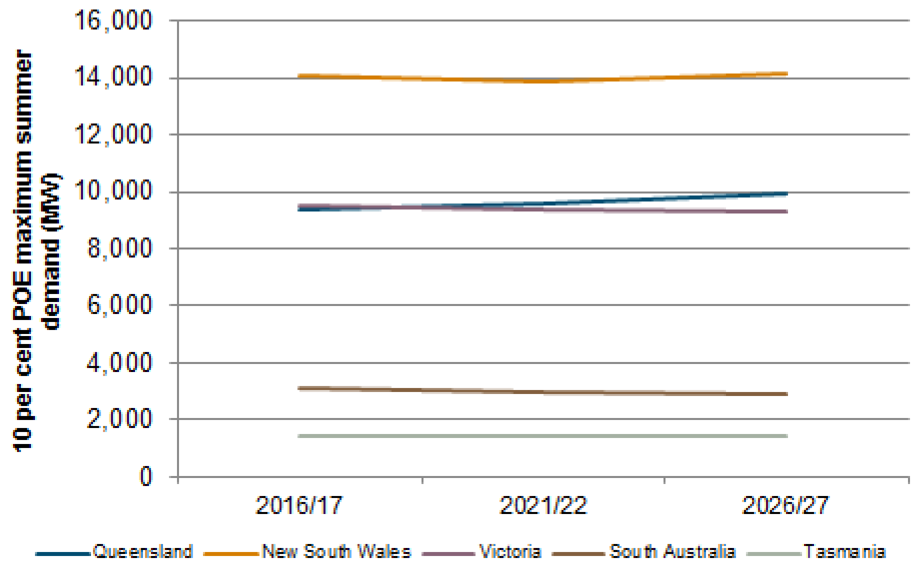
137 The other business sector includes industries such as education, financial services, IT, infrastructure, and health and aged care. AEMO, *Business consumption - key insights*, accessed 8 January 2018 at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/Business-consumption.

138 While AEMO considers that maximum demands across regions are unlikely to occur at the same time, it is not uncommon for high demand conditions to be experienced across multiple regions. For example, on 18 and 19 January 2018 New South Wales, Victoria and South Australia all experienced very high demand.

139 AEMO, *Update: National Electricity Forecasting Report*, March 2017, p. 24.

For all NEM regions, with the exception of 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 3.3 shows the forecast 10 per cent probability of exceedance (POE) maximum summer demand for each region.[140]

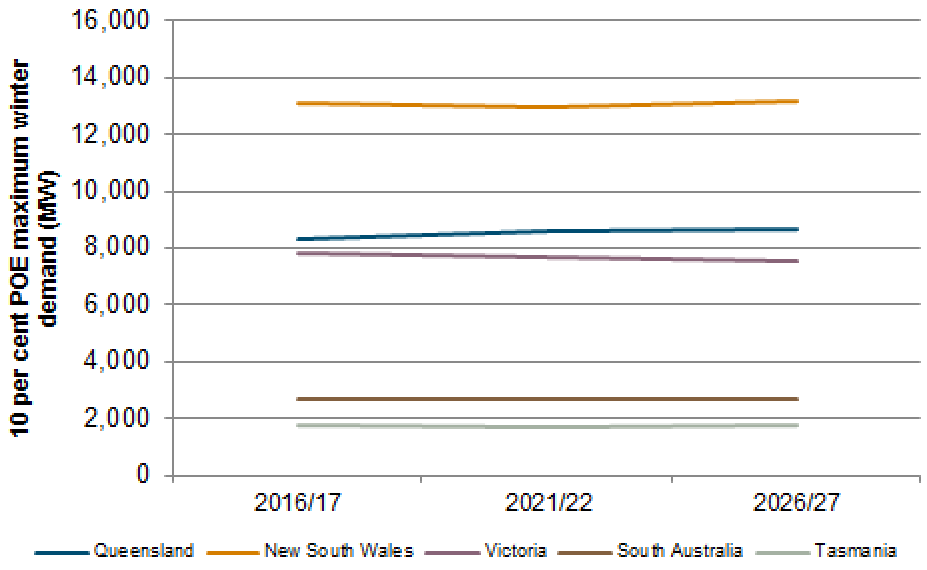
Figure 3.3 Forecast maximum summer demand



Source: AEMO, *2017 Electricity Statement of Opportunities*, September 2017, p. 15.

Figure 3.4 shows the forecast 10 per cent POE maximum winter demands.

Figure 3.4 Forecast maximum winter demand



Source: AEMO, *2017 Electricity Statement of Opportunities*, September 2017, p. 15.

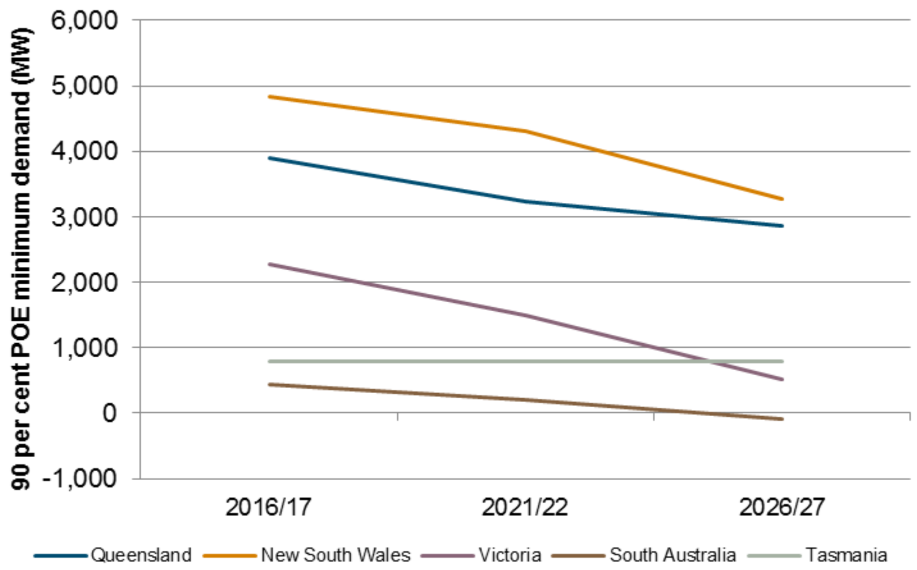
140 Probability of exceedance is the probability, as a percentage, that a maximum demand level will be met or exceeded. For example, a 10 per cent POE forecast of maximum demand is expected to be met or exceeded on average one year in ten.

For New South Wales, Victoria and Tasmania maximum demand forecasts were generally flat. Maximum demand in Queensland is forecast to grow 6.1 per cent over the next ten years. Over the same period, maximum demand in South Australia is forecast to fall by 5.6 per cent. The key points for forecasts of 10 per cent POE maximum demand are:[141]

- Forecast maximum operational demand is shifting to later in the day, when the contribution of rooftop PV is falling but temperatures remain high.
- Maximum demand in Queensland is forecast to increase due to increased cooling load and projected growth in demand by the CSG sector.
- Maximum demand in South Australia is forecast to decrease due to projected increases in rooftop PV, battery storage, and energy efficiency improvements.

Figure 3.5 shows the forecast 90 per cent POE minimum demand for each NEM region.[142] A 90 per cent POE forecast is a forecast that is expected to be exceeded in nine years in ten. In Figure 3.5, this means that the minimum demand is expected to exceed the level shown for nine years in ten.

Figure 3.5 Forecast minimum demand



Source: AEMO, *2017 Electricity Statement of Opportunities*, September 2017.

From 2016/17 to 2026/27, minimum demand is forecast to decrease in all NEM regions except Tasmania.[143] Minimum demand in Tasmania is expected to remain relatively flat over the period. In relation to forecasts of 90 per cent POE minimum demand, the Panel also recognises:

- Increasing rooftop PV uptake is expected to result in the time of minimum demand moving to the middle of the day for Queensland, New South Wales and

141 AEMO, *2017 Electricity Statement of Opportunities*, September 2017, p. 15.

142 For the neutral sensitivity.

143 Minimum demand typically occurs when there is neither heating nor cooling load. This generally happens in the shoulder months, in all regions except Tasmania. Tasmania's minimum demand occurs in summer.

Victoria. South Australia is currently experiencing minimum demand in the middle of the day.

- In South Australia, minimum demand is expected to be negative by 2026/27.

Falling levels of minimum demand may pose operational challenges. In relation to voltage control, AEMO has stated "low minimum demand can lead to high voltages due to lightly loaded transmission lines. These high voltages can, if in excess of operating limits, threaten the continued operation of the power system."[144]

Negative minimum demand in South Australia

The most significant projection in relation to minimum demand is that, as noted above, minimum demand is expected to be negative in South Australia by 2026/27 as output from rooftop PV generation is expected to exceed customer demand in some hours.[145]

Revised forecasts published in AEMO's *South Australian Electricity Report* and presented in Figure 3.6, suggest negative minimum demand in South Australia may occur as early as 2025-26.[146] South Australia could store this excess generation or export it to the rest of the NEM via the interconnectors, provided they are in service. AEMO notes "this signals the important need for market and regulatory frameworks that support storage solutions and maximise the efficiency or shared electricity services for consumers".[147]

In South Australia minimum demand has shifted from overnight to near midday in 2012/13. In response to forecasts of negative minimum demand it has been suggested that the "controlled load" of electric hot water systems should be shifted from the night time to midday hours. However shifting this controlled load may involve significant expense.

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.

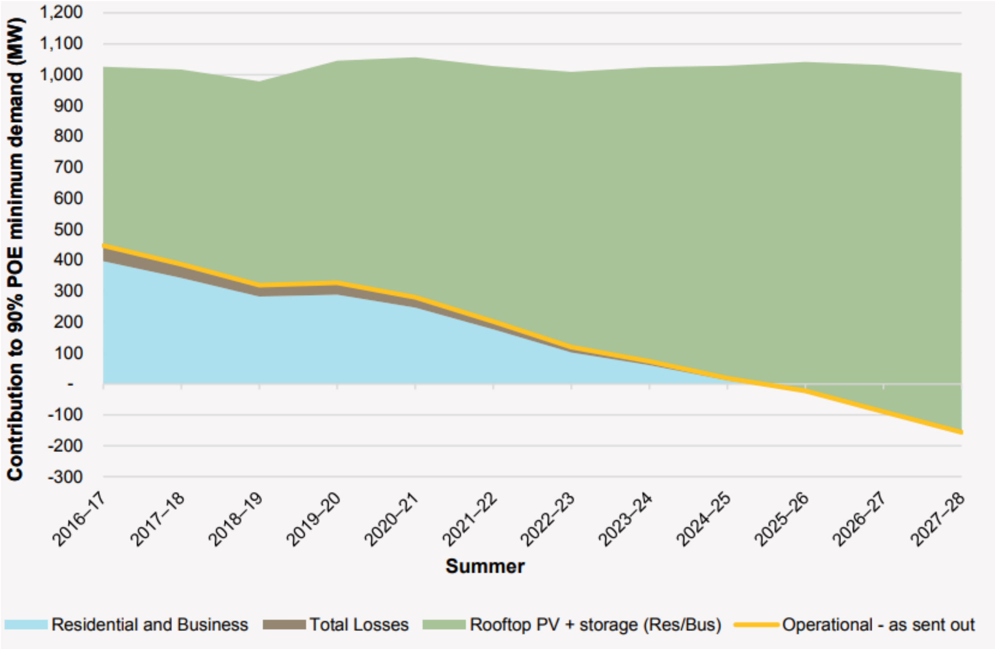
144 AEMO, *2017 Victorian Annual Planning Report*, June 2017, p. 2. AEMO notes temporary operational measures have successfully been applied during periods of minimum demand to maintain voltages within operating limits. AEMO is assessing the benefits of additional reactive power support as a longer-term solution, and will pursue options for procurement as required. AEMO recognises that some connection point minimum demands are reducing at a much faster rate than the regional total, and is examining the potential for localised issues in more detail.

145 More than 30 per cent of dwellings in South Australia now have rooftop PV systems installed. AEMO, *South Australian Electricity Report*, November 2017, p. 2.

146 This is likely to occur if mild summers are experienced.

147 AEMO, *Electricity forecasting insights*, June 2017, p. 8.

Figure 3.6 Minimum demand in South Australia



Source: AEMO, *South Australian Electricity Report*, November 2017 p. 23.

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 changes to the NEM generation mix in 2016/17 include the following key trends:

- **Retirement of thermal generation:** the NEM has experienced a withdrawal of thermal, synchronous generation.[148] The withdrawal of Hazelwood Power Station (1600MW) represented a 13 per cent decrease in the total installed generation capacity in Victoria, and an overall decrease of three per cent in the generation capacity in the NEM.
- **Increase in intermittent renewable generation:** The NEM has experienced a significant growth in large-scale intermittent renewable generation.[149]
- **Increase in distributed energy generation:** There has been a significant increase in the amount of distributed energy generation. The vast majority is residential

148 Since 2008, 4.4GW of coal fired generation has been withdrawn from the NEM, approximately representing a nine per cent decrease in the available synchronous capacity in the NEM.

149 Consistent with the rules this paper uses the term 'intermittent generation' to describe a "generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability" (Chapter 10, Glossary). The Panel recognises that other terms are in use such as 'variable renewable electricity generation'. The purpose of utilising a specific term to collectively refer to certain renewable technologies is to simplify discussion of the particular shared characteristics of their generation availability (or variability).

PV, of which the installed capacity reached around 6GW by the end of 2016/17.[150]

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 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.

These changes 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 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.

These reliability and security impacts of changing generation mix are explored further in chapters 4 and 5.

3.2.2 Generation capacity

At the end of 2016/17, the total installed generation capacity in the NEM was 47.05GW.[151] By fuel type generation capacity was comprised of:

- 48.8 per cent coal
- 23.5 per cent gas
- 16.9 per cent hydro
- 8.7 per cent wind
- 2.1 per cent other, which includes 0.6 per cent large scale solar.

The regional breakdown of generation is shown in Figure 3.7

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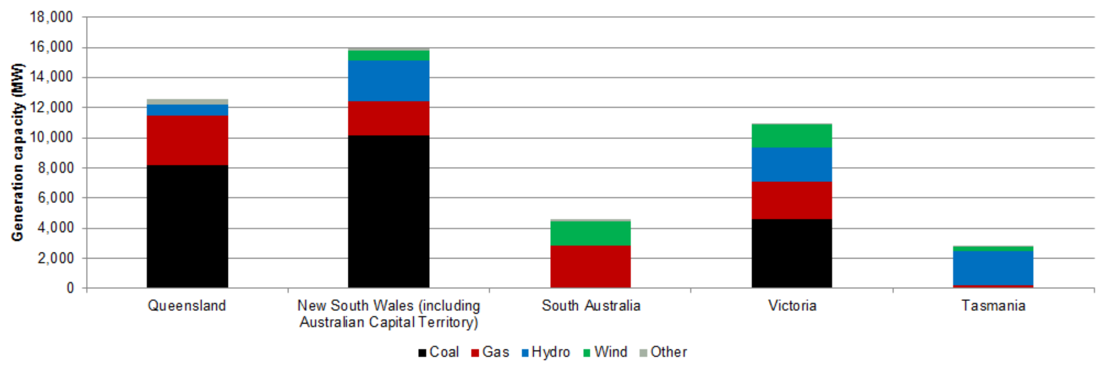
150 Clean Energy Regulator, *Postcode data for small-scale installations*, accessed 8 December 2017, avaliable at http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#Small-generation-unit-SGU-installations

151 Including scheduled, semi-scheduled, and non-scheduled installed capacity, but excluding rooftop PV. This figure includes the full capacity of Pelican point (478 MW), available to the market as of 1 July 2017. It also includes the full capacity of Smithfield Power Station (171 MW), which was scheduled for closure in July 2017; 109 MW of capacity at Smithfield was made available for summer 2017/18 with the units now operating in open cycle gas turbine mode. The total installed generation figure excludes Swanbank E Power Station (385 MW) in Queensland and Tamar Valley Power Station (208MW) in Tasmania. Both these power stations were mothballed as of the end of 2016/17 but returned to service for summer 2017/18.

Figure 3.7 Regional breakdown of generation by fuel type

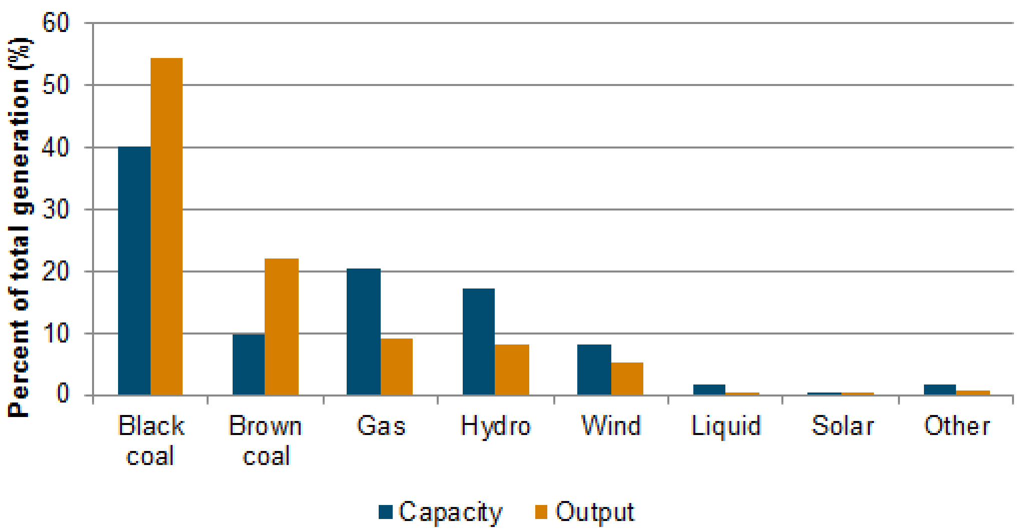


Source: AEMO, *Generator information page*

Despite increased penetration of intermittent renewable generation and withdrawal of thermal coal-fired power generation, coal-fired power still accounts for around half the installed generation capacity in the NEM. On a regional basis coal-fired generation makes up a substantial portion of the generation capacity in Queensland (65 per cent), New South Wales (62 per cent) and Victoria (42 per cent). In South Australia gas-fired generation comprises 62 per cent of the generation capacity. In Tasmania abundant hydro resources mean that over 80 per cent of installed Tasmanian generation capacity is hydro.

Additionally, as shown in Figure 3.8 coal-fired power also accounts for the large majority of energy generated. Coal-fired generation typically operates with a high capacity factor.[152]

Figure 3.8 Generation and capacity per technology type



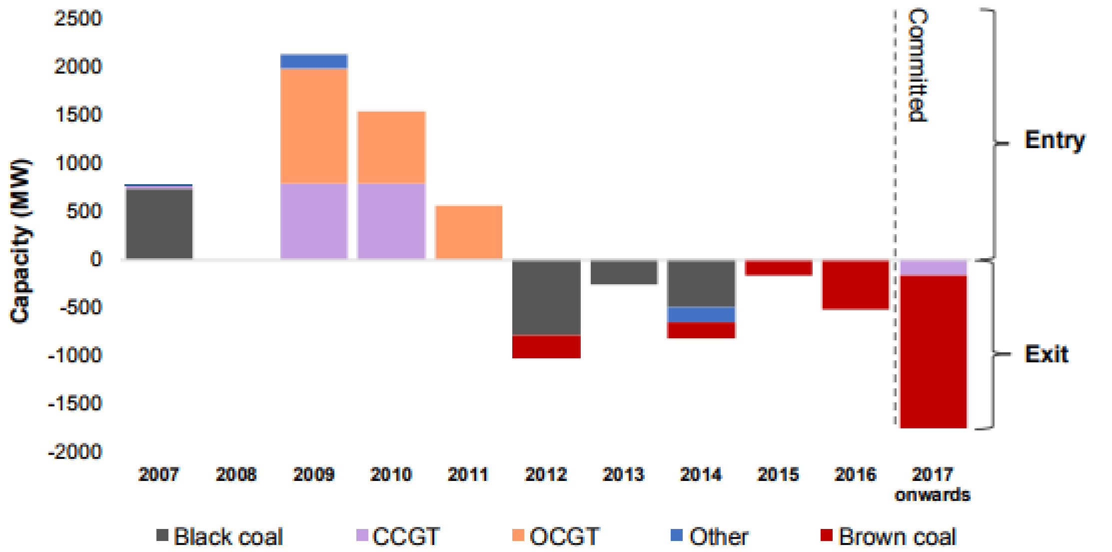
Source: AER, *Wholesale statistics page*, accessed 8 December 2017

152 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 100MW and over a year the average generation output from the generator was 80MW, that generator would have a capacity factor of 80 per cent.

To date, the NEM has experienced a significant change in the generation mix. Figure 3.9 and Figure 3.10 below demonstrate the changes in thermal and intermittent generation capacity since 2007.

Figure 3.9 shows that between 2007 and 2011 around 4.5GW of new thermal (typically synchronous) generation entered the NEM, and between 2012 and 2017 4.8GW of this thermal generation exited the market.

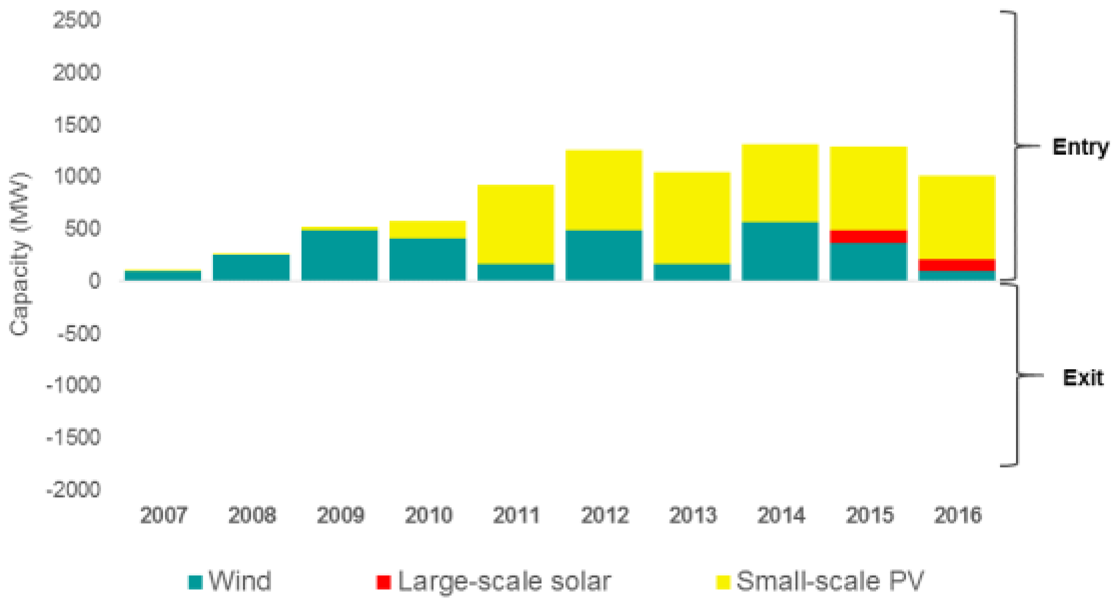
Figure 3.9 Changes in thermal generation capacity by fuel type



Source: Endgame Economics analysis of the AEMO Market Management System database

Figure 3.10 shows that since 2007, the capacity of intermittent (typically asynchronous) renewable generation has significantly and consistently grown to around 7.5GW, with solar PV making up an increasing share of new intermittent generation entry since 2011.

Figure 3.10 Changes in intermittent generation capacity by technology type



Source: Endgame Economics analysis of the AEMO Market Management System database

3.2.3 Generation withdrawals

In 2016/17, 1808MW of generation was formally withdrawn. The most significant withdrawal was the closure of the Hazelwood Power Station in Victoria. The 1600MW brown coal power station was permanently shut down on 29 March 2017. At the time of its closure, the 52 year old generator was the most emission intensive generator in the NEM.[153]

The withdrawal of Hazelwood Power Station represented a 13 per cent decrease in the total installed generation capacity in Victoria. It also represented a 15 per cent decrease in the total installed synchronous capacity in Victoria.

From the overall perspective of the NEM the withdrawal of Hazelwood Power station represented a three per cent decrease in the total installed generation capacity and a four per cent decrease in the total installed synchronous capacity.

The other withdrawn generator for this period was the Tamar Valley Power Station. Hydro Tasmania stopped operating the 208 MW combined cycle gas turbine in May 2017. However, ahead of the 2017/18 summer the full capacity of the unit was returned to service.[154] Hydro Tasmania has since announced that it will withdraw the Tamar Valley Power Station after April 2018, but that the unit will be available to return to operation with less than three months' notice.[155]

It has been announced that 2064MW of generation will be withdrawn from the NEM by mid-2022. All of the generation units announced for withdrawal are thermal, synchronous units. The generators announced for withdrawal are:[156]

- AGL has announced its intention to withdraw the Liddell Power Station (2000MW) in New South Wales in March 2022.
- Stanwell has announced its intention to withdraw the Mackay GT Power Station (34MW) in Queensland in July 2021.
- Energy Infrastructure Investments has announced its intention to withdraw the Daandine Power Station (30MW) in Queensland in June 2022.

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 generation coal and gas-fired generation also has implications for system security, including through reducing the amount of inertia and potentially contributing to a reduction in the availability of ancillary services in the NEM. These ancillary services include Frequency Control Ancillary Services (FCAS) and System Restart Ancillary Services (SRAS). These system security implications are discussed in chapter 5.

153 ACIL Allen, *Emissions factors assumptions update, final report,* 10 May 2016, p.8.

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

155 AEMO, *Generator Information page*, 29 December 2017.

156 No generator in Tasmania or South Australia has currently announced its intention to withdraw plant.

This withdrawal may also affect the ability of network service providers and AEMO to manage voltage and other system stability requirements throughout the system. This is because synchronous generation has traditionally supported the management of system stability, due to the operational characteristics of this generation type.

Other developments relating to generator withdrawals

In December 2017, AGL announced its *New South Wales Generation Plan* that outlined how it proposed to replace the Liddell Power Station.[157] Its multi-stage proposal consisted of investments in new, low emissions generation and upgrades to existing infrastructure. The proposed solution includes two gas peaking plant (500MW and 250MW), demand response (up to 150MW), generation from renewable sources (1600MW), a battery (250MW), the upgrade of Bayswater Power Station (100MW) and the conversion of generators at Liddell into synchronous condensers. AGL will also explore the feasibility of a pumped hydro project in the Hunter region with the NSW Government.

Visy Power Generation closed the Smithfield Power Station (176MW) at the end of July 2017. However 109MW of gas-fired capacity at Smithfield was made available for summer 2017/18.[158]

Stanwell placed the Swanbank E Power Station into cold storage in 2014. The Queensland Government, as asset shareholder, directed Stanwell Corporation to return the Swanbank E gas-fired power station to full operational capacity (385MW) from 1 January 2018.[159]

Engie reduced the capacity of the Pelican Point Power Station in South Australia by half in April 2015. From July 2017 it was returned to its full capacity of 479MW.[160]

3.2.4 Commissioned and committed generation

New generation projects are typically grouped as either committed or commissioned:

- 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.[161]
- 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.[162]

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157 AGL, *New South Wales Government Plan*, December 2017.

158 109MW is the re-registered capacity of the power station with the units now operating in open cycle gas turbine mode. AEMO, *Summer operations 2017/18, final report*, November 2017, p. 14 and AEMO, *Generator Information page*, 29 December 2017.

159 Stanwell, *Swanbank E Power Station to return to service*, June 2017.

160 AEMO, *Generator information page*, 22 December 2017.

161 AEMO, *Generator Information page*, 29 December 2017.

162 More information on the generation project commitment criteria is available in the regional generation information pages, accessible at:

In 2016/17, 441MW of new generation was commissioned.[163] This is compared to 109MW in 2015/16, 1074MW of generation commissioned in 2014/15, and 170MW of generation commissioned in 2013/14.

Notably, all of the new commissioned projects are intermittent, non-synchronous generation units.

In terms of capacity, the main generation projects commissioned in 2016/17 are:

- Ararat Wind Farm (240MW) in Victoria has been in full commercial operation since April 2017.
- Hornsdale Wind Farm Stage 1 (102MW) in South Australia has been in full commercial operation since January 2017.[164]

In 2016/17, 1312MW of generation was committed. This compares to 537MW of generation committed in 2015/16, 240MW of generation committed in 2014/15 and 1165MW of generation committed in 2013/14.

In terms of capacity, the main generation projects committed in 2016/17 are:

- Bungala Solar Power Project (220MW) in South Australia
- Hornsdale Wind Farm Stage 2 and Stage 3 (211MW) in South Australia
- Mt Emerald Wind Farm (181MW) in Queensland
- White Rock Wind Farm (173MW) in New South Wales
- Clare Solar Farm (100MW) in New South Wales.

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

3.2.5 Increased rooftop PV and distributed storage

In response to the rapid expansion of solar generating capacity in the NEM, AEMO has produced forecasts of residential and commercial solar PV capacity. Additionally, AEMO has forecast the uptake of integrated systems consisting of rooftop PV and storage systems.

Forecast uptake

Figure 3.11 shows AEMO's forecasts of projected uptake of rooftop PV. AEMO is forecasting strong growth in rooftop PV in all NEM regions, except Tasmania.[165] New South Wales is forecast to experience the fastest rate of uptake. The total installed capacity of rooftop PV in 2035/36 is projected to be over 18.6GW.

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https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

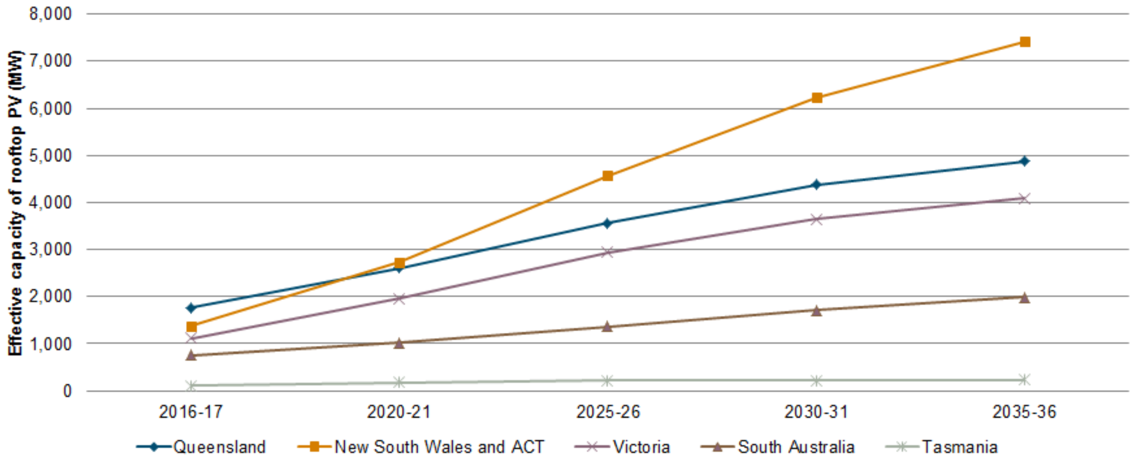
163 This new generation was predominantly wind generation.

164 Though not commissioned during the 2016/17 period the Hornsdale Power Reserve Unit 1 (100MW/129MWh) battery storage was operational as of 1 December 2017.

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

To put this in perspective, 18.6 GW is equivalent to around 40 per cent of the total installed generation capacity currently in the NEM.

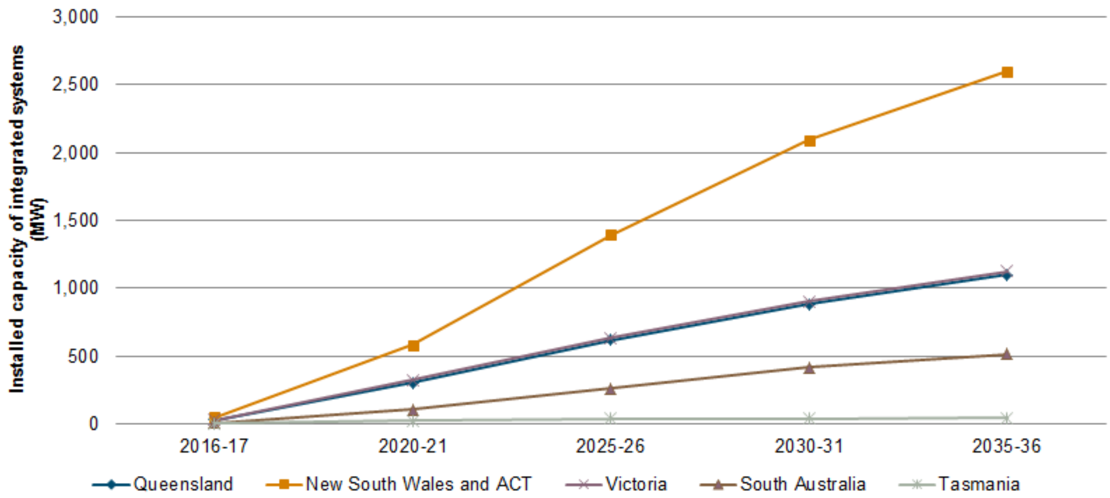
Figure 3.11 Installed rooftop PV capacity forecasts



Source: AEMO.

Figure 3.12 shows AEMO's forecasts of projected uptake of integrated PV and storage systems. AEMO is forecasting strong growth in integrated PV and storage systems in all NEM regions, except Tasmania.[166] New South Wales is forecast to experience the fastest rate of uptake.[167] The total installed capacity of integrated PV and storage systems is projected to be 5.4GW.

Figure 3.12 Integrated PV and storage systems capacity forecast



Source: AEMO.

166 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.

167 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.

The drivers for PV and integrated PV and storage systems uptake in each region vary due to regionally specific characteristics:[168]

- **Queensland:** The strong growth in the uptake of rooftop PV and integrated PV and storage systems in the commercial sector is projected to offset the saturation in residential installations that is expected to be reached in some areas.
- **New South Wales and the Australian Capital Territory:** New South Wales is expected to become the region with the largest installed capacity of PV systems. This is mainly because this region has the highest number of projected connections. Strong growth of integrated PV and storage systems is forecast, driven mainly by expected declining battery costs.
- **Victoria:** Residential PV uptake in Victoria is forecast to grow steadily until the mid-2020s. Projected uptake in the commercial sector remains steady across the outlook period.
- **South Australia:** South Australia currently has the highest penetration of residential rooftop PV of all the NEM regions. As a result, the region is forecast to reach saturation earlier than most others, causing forecast growth to decline towards the end of the outlook period. Some of the projected decline in residential growth is expected to be offset by a higher projected uptake of commercial PV systems.
- **Tasmania:** Tasmania continues to have slower forecast growth of PV installations compared to the other regions, in both the residential and commercial segments, due to lower levels of sunshine reducing the financial attractiveness of systems.

Impacts on consumption and maximum demand

Increased rooftop PV reduces both operational consumption and the level of demand during the day. In terms of general changes in consumption, increased PV generation has been a major contributor to the historical decline in operational consumption.

In terms of demand, increased rooftop PV can exacerbate the difference in demand levels during the middle of the day, when PV output is at a maximum and therefore significantly reduces demand, and early evening, when PV output declines. This can result in a "hollowing out" of the typical daily demand curve.

As discussed in section 3.1.3, increased rooftop PV is forecast to reduce minimum demand levels, as well as shifting the timing of minimum demand in each region from overnight to midday.

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.[169]

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168 AEMO, *Rooftop and Battery Storage*, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/Key-component-consumption-forecasts/PV-and-storage, accessed 11 December 2017.

169 This is considered in greater detail in chapters 3 and 4 of the AEMC's *Reliability frameworks review.*

The impact of increased integrated PV and storage system capacity is not as clear. Integrated PV and storage systems allow for the output of PV generation to be stored during the day and then used during evening peaks.[170] One 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.

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 partly insulate households and small businesses from the impacts of interruptions in grid supply. This impact of integrated PV and storage is discussed in section 2.6.2 of the Panel's *Reliability standard and settings review*.[171]

3.3 Bulk transfer capability, upgrades and performance

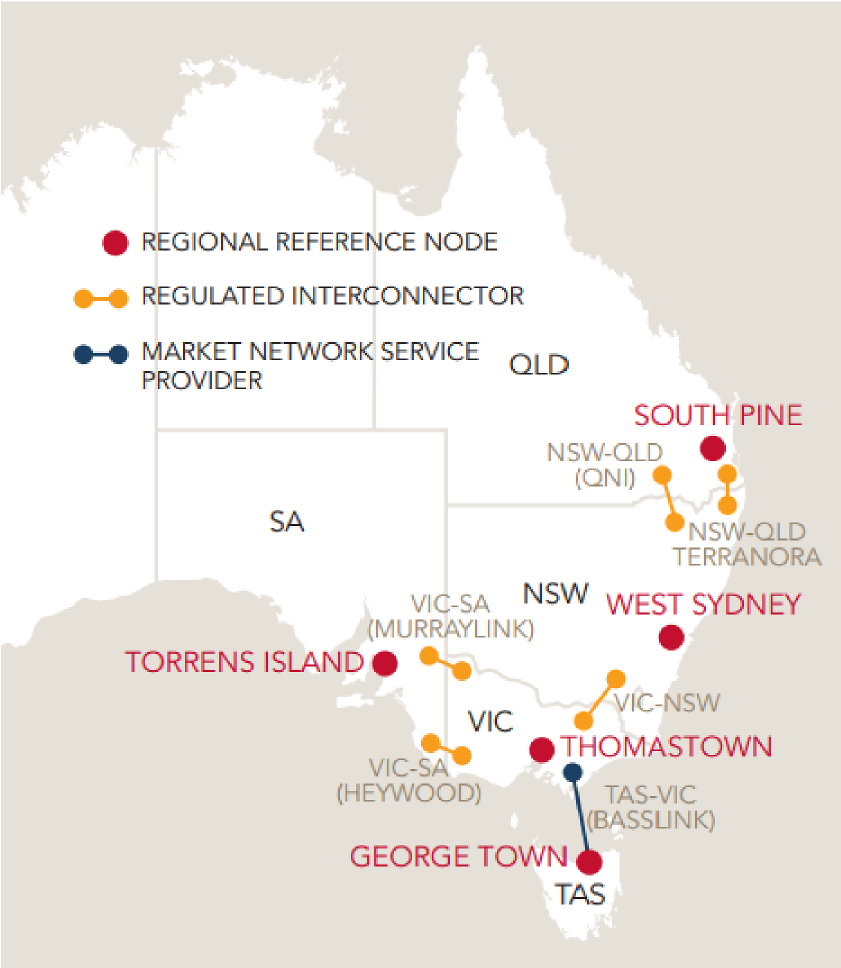
The interconnected transmission network in the national electricity market is important for facilitating a reliable supply of electricity to consumers and to support the NEM wholesale market by allowing electricity to be bought and sold across regions.[172] The physical location of each interconnector in the NEM is shown in Figure 3.13

170 For AEMO's maximum and minimum operational demand forecasts, presented in section 3.1.3, battery storage has been assumed to have a fixed charging/recharging schedule. Battery storage is assumed to charge up during the period of the day when rooftop PV generates the most electricity, and discharge evenly during the evening period. This lifts minimum demand and lowers maximum demand projections accordingly at these times. AEMO, *Electricity Forecasting Insights*, June 2017, p. 8.

171 Reliability Panel, *Reliability standard and settings review 2018, draft report*, November 2017.

172 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 3.13 Interconnectors in the NEM



Source: AEMO, *An introduction to Australia's National Electricity Market*, p. 15.

This section discusses:

- the modelled effects of increased interconnection
- the upgrade of the Heywood interconnector, completed in August 2016[173]
- several proposals for interconnector upgrades[174]
- the performance of interconnectors.

3.3.1 Modelled impacts of increased interconnection

The *2016 National Transmission Network Development Plan* (NTNDP) modelled the impacts of increased interconnection of the NEM, i.e. more interconnectors between regions.[175] The 2017 NTNDP has been incorporated into AEMO's *Integrated System Plan* to be released in June 2018. As such much of this section has been informed by the 2016

173 AEMO, *Victorian annual planning report*, June 2017, p21.

174 Responsibility for planning of the transmission network in the NEM is generally shared between AEMO in its role as National Transmission Planner and the transmission network service providers (TNSPs) in the NEM.

175 AEMO, *National transmission network development plan*, December 2016.

NTNDP. High level modelling suggests positive net benefits for potential interconnection developments, if they are competitively priced. These interconnection developments include:[176]

- a new interconnector linking South Australia with either New South Wales or Victoria from 2021
- augmenting existing interconnection linking New South Wales with both Queensland and Victoria in the mid to late 2020s
- a second Bass Strait interconnector from 2025, when combined with augmented interconnector capacity linking New South Wales identified above, although the benefits are only marginally greater than the costs.

The 2016 NTNDP modelling also found that:[177]

- There are greater total net benefits when interconnection developments are combined, creating a more interconnected NEM. These benefits are also projected to increase as energy sector transformation accelerates.
- Greater interconnection facilitates geographic and technological diversity. This diversity smooths the impact of intermittency and reduces reliance on gas-powered generation, delivering fuel cost savings to consumers.
- Interconnection does not necessarily solve all challenges. Local network and non-network options are also needed to maintain a reliable and secure supply. Synchronous condensers, or similar technologies, will be required to provide local system strength and resilience to frequency changes.

3.3.2 Heywood upgrade

In August 2016, the Heywood interconnector, which connects Victoria and South Australia, was upgraded to allow increased power flows between the two regions. The interconnector's increased maximum design limit of 650MW flow in both directions has not yet been fully released into the market.[178]

The South Australian transmission network service provider ElectraNet and AEMO identified the classes of market benefit as material in the Heywood Interconnector regulatory investment test for transmission (RIT-T), including changes in:

- generator fuel consumption
- voluntary load curtailment
- involuntary load shedding
- costs for other parties
- network losses.[179]

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176 AEMO, *National transmission network development plan*, December 2016, p. 3.

177 AEMO, *National transmission network development plan*, December 2016, p. 3.

178 Prior to the upgrade, the Heywood interconnector's capacity was 460MW.

179 AER, *South Australia - Victoria (Heywood) interconnector upgrade: Determination that preferred option satisfies the regulatory investment test for transmission*, September 2013.

ElectraNet and AEMO found that the net economic benefits arising from the Heywood upgrade were equivalent to $190.8 million ($2011/12).

The upgrade comprised of the installation of a third transformer at Heywood and series compensation on 275kV transmission lines in South Australia, a control scheme for the South East transformers and 132kV network reconfiguration works in South Australia.

AEMO's analysis of the South Australian black system event, which occurred in September 2016, has identified a potential transient stability issue which is seen during high Victoria to South Australia transfers and high levels of wind generation in South Australia.[180] AEMO and ElectraNet are currently reviewing the transient stability limits and transfer limits applied to the interconnector. Currently, the Heywood interconnector's transfer limit from Victoria to South Australia is set at 600MW, while the transfer limit from South Australia to Victoria is set at 500MW.[181]

3.3.3 Proposed additional interconnector with South Australia

In November 2016, ElectraNet released a Project Specification Consultation report as part of a RIT-T process.[182] The report provided an economic cost benefit assessment of various network and non-network solutions to assist the management of South Australia's increasing penetrations of renewable energy. The report presented five credible options, four of which were new interconnectors:[183]

1. Interconnector linking central South Australia to Victoria - this line would be 350 - 600km with a capacity of 300 - 650MW. The indicative cost is $500 - 1000 million.
2. Interconnector linking mid-north South Australia to New South Wales - this line would be 300 - 800km with capacity of 300 - 1,200MW. The indicative cost is $500 - 1500 million.
3. Interconnector linking northern South Australia to New South Wales - this line would be 1,100 - 1,300km with a capacity of 1,000 - 2,000MW. The indicative cost is $1500 - 2000 million.
4. Interconnector linking northern South Australia to Queensland - this line would be 1,450 - 1,600km with a capacity of 1,000 - 2,000MW. The indicative cost is $2000 - 2500 million.
5. Non-network solution - this would consist of a variety of non-network capabilities to provide fast frequency response, inertia and system strength; e.g. large-scale batteries, demand management, generation. This indicative cost of this option is to be informed by submissions to ElectraNet.

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180 AEMO, *Victorian Annual Planning Report*, June 2017, p. 16. The South Australian black system event is discussed in more detail in section 5.2.1 of this report

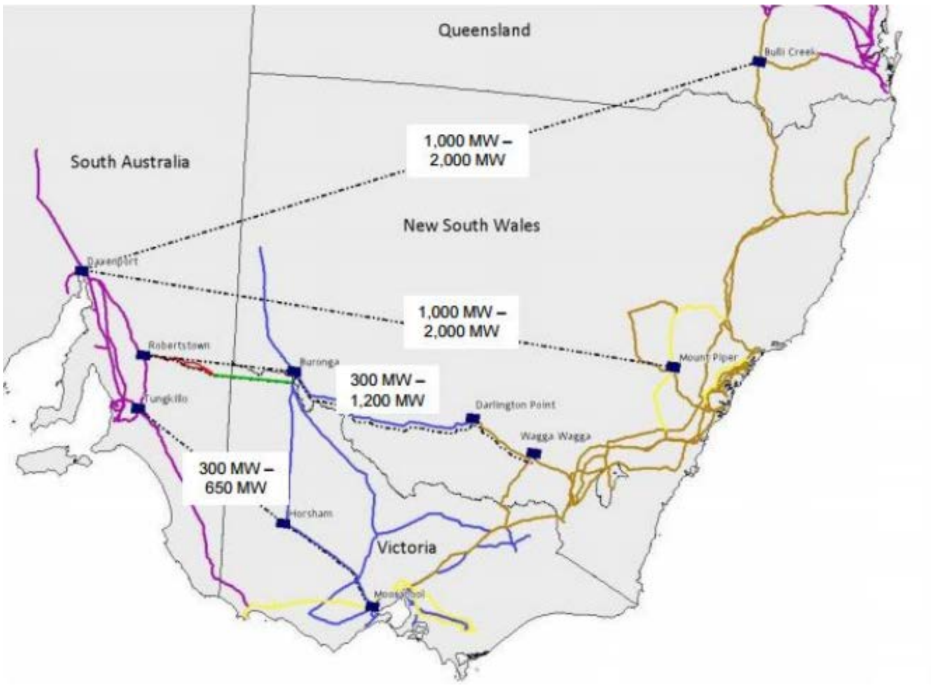
181 AEMO, *Interconnector capabilities*, November 2017, p. 6.

182 RIT-T stands for regulatory investment test for transmission. The rules require that a transmission network service provider undertake a RIT-T for any projects with an estimated cost of more than $6 million. The purpose of a RIT-T is to identify the transmission investment option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market, after performing cost-benefit analysis on a number of credible options..

183 ElectraNet, *RIT-T: Project Specification Consultation Report*, November 2016.

The four options of building an additional interconnector are shown in Figure 3.14.

Figure 3.14 Proposed interconnectors with South Australia



If the decision to construct an interconnector is made, the expected energisation would take place in 2021 or 2022 depending on which option was chosen.

3.3.4 Second interconnector with Tasmania

The Commonwealth and Tasmanian Governments requested a feasibility study for a second electricity interconnector between Tasmania and Victoria to help address long-term energy security issues and facilitate investment in renewable energy.

The final report was completed in January 2017 and published in April 2017. The final report found that building a second interconnector between Tasmania and the mainland not to be economically feasible under present market conditions. The report recommended that the Tasmanian Government monitor market conditions and develop a business case for a second Tasmanian interconnector if either of the following occurs:

- AEMO concludes in a future NTNDP that a second Tasmanian interconnector would produce significant market benefits under most plausible circumstances
- additional interconnection is approved for construction between South Australia and the eastern states
- demand for electricity in Tasmania reduces materially.[184]

AEMO in its role as the national transmission planner is set to review a second Bass Strait interconnector as part of its least cost generator and transmission outlook, and its conclusion is expected to be reported in the *2018 Integrated System Plan*.

184 Commonwealth of Australia and Tasmanian Government, *Feasibility of a Second Tasmanian interconnector - Final Study*, April 2017

On 24 November 2017, the Commonwealth and Tasmanian Governments announced they would invest up to $20 million for a business case study for a second Tasmanian interconnector. Preliminary findings from Hydro Tasmania's *Battery of the nation* study indicate that "a second interconnector could enable Tasmania to expand its wind and hydro capabilities and add more power to the national grid, with a net benefit of $500 million".[185] TasNetworks, as the proponent, are working with the Australian Renewable Energy Agency (ARENA) to develop a proposal for formal assessment. The business case study would examine and finalise the preferred route, optimum size, cost estimate, revenue investment test and financial model for a second interconnector between Tasmania and Victoria.

3.3.5 Proposed additional interconnector developments

Based on AEMO's preliminary modelling presented in the consultation paper for the *2018 Integrated System Plan*:[186]

- Following the announced closure of Liddell Power Station in 2022 and changed market conditions, AEMO recommends that Powerlink and TransGrid initiate a RIT-T to increase transfer capacity between Queensland and New South Wales. The AER has accepted Powerlink's proposal for an upgrade of QNI to be included as a contingent project in its 2017-22 regulatory control period.[187]
- AEMO recommends that a joint planning study should commence in 2018 to determine the feasibility and preferred option to upgrade the Victoria to New South Wales interconnector.

3.3.6 Interconnector performance

Power transfer across an interconnector is limited by the capability of network elements which make up the interconnector (thermal limitations), or the ability to maintain the system in a secure state in the event of a contingency (transient or voltage stability limitations). These limits are applied in the form of constraint equations in the National Electricity Market Dispatch Engine (NEMDE) process.[188]

During normal operation of the power system, transfer across an interconnector will ultimately be limited by constraints within the NEMDE dispatch process. However, the power system operates in a dynamic environment and there are instances where interconnector transfer can exceed their secure limit for a small period of time.

During 2016/17, there were a number of significant operating incidents involving interconnectors. These included:

185 Prime Minister, *Minister for the Environment and Energy, Media release - Government invests in business case for a second Tasmanian interconnector*, 24 November 2017

186 AEMO, *Integrated System Plan Consultation*, December 2017, p. 38.

187 AER, *Final decision - Powerlink transmission determination, 2017-18 to 2021-22*, April 2017

188 NEMDE is the dispatch engine for the NEM. It is used by AEMO to dispatch generators. More information is available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability%20/Dispatch-information

- **28 September 2016, South Australia:** Multiple faults on the transmission network resulted in a reduction in wind farm output that caused a significant increase in imported power flowing through the Heywood interconnector. Approximately 700 milliseconds (ms) after the reduction of output from the last of the wind farms, the flow on the Heywood interconnector reached such a level that it activated a special protection scheme that tripped the interconnector offline.[189] This event is discussed in further detail in section 5.2.1.
- **1 December 2016, South Australia and Victoria:** A fault on the Moorabool to Tarrone 500kV transmission line in Victoria resulted in the loss of the Heywood interconnector.[190] This event is discussed in further detail in section 5.2.2.
- **8 February 2017, South Australia:** The deteriorating supply/demand balance in South Australia pushed the flow into South Australia on Murraylink above AEMO's target limit, meaning the power system was not in a secure operating state. Load was shed to manage the security violation.[191] This event is discussed in further detail in section 4.2.1.
- **10 February 2017, New South Wales:** The three interconnectors to New South Wales were above their limits, due to the combination of the loss of the Tallawarra generating unit and the failure of the Colongra generating units to start. This meant the power system was not in a secure operating state.[192] This event is discussed in further detail in section 5.2.3.
- **3 March 2017, South Australia:** Faults at the Torrens Island switchyard resulted in the near simultaneous disconnection of 410 MW of generation. This resulted in the power flow on the Heywood interconnector peaking well above its limit.[193] This event is discussed in further detail in section 5.2.4.
- **12 March 2017, Tasmania:** A decrease in flow and subsequent trip of Basslink resulted in a low frequency event in Tasmania. This led to load shedding - the under frequency load shed scheme in Tasmania operated correctly and as expected.[194]
- **29 March 2017, Queensland:** The Mudgeeraba No. 2 and No. 4 110kV busbars tripped out of service. As a result of the incident, the Mudgeeraba – Terranora 758 110kV line was disconnected, interrupting supply to Terranora Substation in New South Wales and offloading Directlink.[195]

Figure 3.15 shows annual interregional trade as percentage of regional energy consumption. Over the last decade South Australia has imported an increasing amount

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189 AEMO, *Black System South Australia 28 September 2016 - Final report,* 28 March 2017, p. 6.

190 AEMO, *Final report - South Australian Separation Event, 1 December 2016,* 14 June 2017, p. 2.

191 AEMO, *System event report South Australia, 8 February 2017*, 15 Feb 2017, p. 2.

192 AEMO, *System event report South Australia, 8 February 2017,* 15 Feb 2017, p. 2.

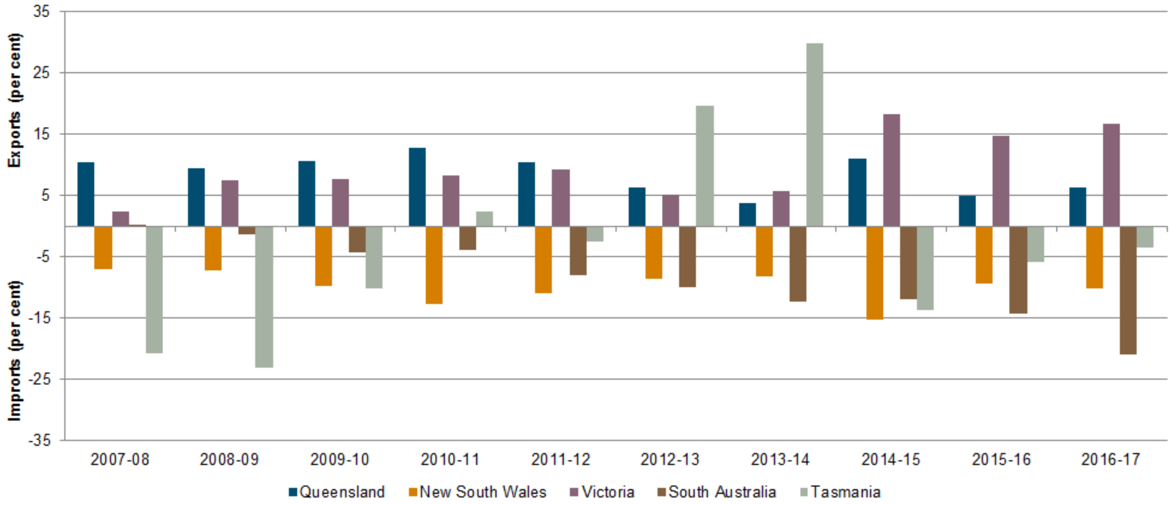
193 AEMO, *Fault at Torrens Island Switchyard and loss of multiple generating units, 3 March 2017*, 10 March 2017, p. 6.

194 AEMO, *Basslink outage and under frequency load shedding in Tasmania, 12 March 2017*, 10 March 2017, p. 4.

195 AEMO, *110KV Busbar trip at mudgeeraba substation, 29 March 2017*, 12 July 2017, p. 3.

of energy, corresponding with an increase in Victoria's exports over the same period. Since 2007/08 Tasmania has been both an importer and exporter of energy on annual basis.

Figure 3.15 Annual interregional trade as a percentage of regional energy consumption[196]



Source: AER, *Wholesale statistics*

The Commission notes the growing share of electricity generation coming from renewable energy sources may increase the potential benefits of interconnection.[197] This is because of the following reasons:

- Sources of renewable energy are often further removed from centres of demand than conventional generation.
- The potential to exploit the geographic diversity of intermittent generation sources, which may lead to more efficient generation location decisions, and smoothing of the intermittency in aggregate across the NEM.
- The potential for price separation between regions is likely to increase as a result of lower-cost renewable energy in some regions.
- The intermittency of renewable energy sources such as wind and solar requires sufficient dispatchable generation from other power sources in order to facilitate a reliable power supply. This dispatchable generation may be provided by a generator in another region.

Current transmission bottlenecks

Figure 3.16 below highlights areas of network congestion during 2016/17.[198] Although some degree of network congestion may be economic, increasing congestion is a signal that upgrades might be justified. The figure shows that the bulk of network congestion in 2016/17 resulted from interconnector transfer limits, signalling a potential benefit of

196 New South Wales and Victoria regions gained additional hydroelectric peaking capacity following the abolition of the Snowy Region Rule in July 2008.

197 AEMC, *Last resort planning power, decision report*, November 2017, p. 14.

198 Congestion relating to network outages was removed from this analysis.

upgrading interconnection.[199] This congestion was primarily located between major load centres.

Figure 3.16 2016/17 transmission congestion heat map

Source: AEMO, *Integrated System Plan Consultation,* December 2017, p. 39.

3.4 Reviewable operating incidents during 2016/17

AEMO is required to conduct a review of every reviewable operating incident. A reviewable operating incident is defined in the rules as:[200]

- 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

199 Network congestion was measured by summarising the marginal value for each constraint equation in each dispatch interval over the period.

200 Rules clause 4.8.15

- 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.[201]

In 2016/17 there were 29 incidents that were reviewed in accordance with the operating incident guidelines.[202] Table 3.1 classifies and compares the type and number of incidents with 2015/16.

Table 3.1 Reviewable operating incidents 2015/16 and 2016/17

Incident type	Number of incidents	
	2015/16	**2016/17**
Transmission related incidents (excluding busbar trips)	8	10
Generation related incidents	0	1
Combined transmission and generation incidents	1	2
Busbar related reviewable incidents	7	7
Power system security related incidents	4	9
Total	20	29

Source: AEMO

Table 3.1 shows that in 2016/17 nine more reviewable operating incidents occurred than in 2015/16. 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.[203]

A detailed description of major reliability and system security events that have occurred in the NEM during 2016/17 is provided in section 4.2 and section 5.2.

3.5 Wholesale prices

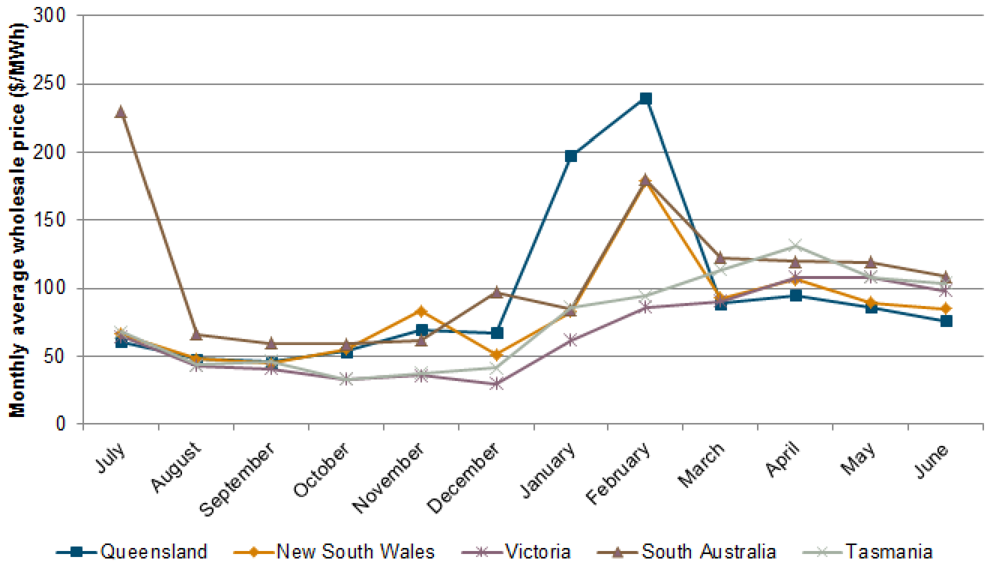
Over the course of the year 2016/17, wholesale prices increased for all regions. Figure 3.17 shows the monthly average wholesale prices in the NEM for 2016/17.

201 The guidelines for identifying reviewable operating incidents can found on the AEMC Reliability Panel website: www.aemc.gov.au.

202 For more information see: http://www.aemc.gov.au/getattachment/50c858eb-8f96-4164-bdad-ccf12b22827f/Final-revised-guidelines.aspx

203 For example, in 2014/15 there were 28 reviewable incidents.

Figure 3.17 Monthly average wholesale prices in the NEM for 2016/17



Source: AEMC analysis of Neopoint database

Table 3.2 compares the time-weighted average prices for 2016/17 with 2015/16 for each region.[204] The yearly time-weighted average price for 2016/17 was higher than last year for all regions except for Tasmania.[205]

Table 3.2 NEM time-weighted average wholesale electricity price (nominal)

Region	2015/16 ($/MWh)	2016/17 ($/MWh)	Movement
Queensland	59.97	93.12	55 per cent increase
New South Wales	51.60	81.22	57 per cent increase
Victoria	46.14	66.58	44 per cent increase
South Australia	61.67	108.66	76 per cent increase
Tasmania	102.71	75.40	27 per cent decrease

Source: AEMO, *South Australian Electricity Report*, November 2017, p. 3.

The Panel notes that:

- Queensland and New South Wales experienced very high demand over the summer which contributed to high prices in these regions over the summer months.[206]

204 Time-weighted average price is a simple average of 30-minute spot market prices over a period of time, and does not take into account the different volumes of energy sold within the interval. It represents the average price a generator would have received if it generated at full capacity for the financial year.

205 Tasmania experienced inflated wholesale prices for a large portion of 2015/16 due to the extended outage of Basslink and limited hydro resources.

206 Over the 2016/17 summer Queensland recorded a new peak demand of 9,508MW, while New South Wales recorded a peak demand of 14,107MW, the highest demand since the 2010/11 summer

- Wholesale prices in Victoria rose following the closure of Hazelwood Power Station on 29 March 2017.
- South Australia experienced sustained high prices in July 2016. AEMO's analysis suggests that the high prices recorded in South Australia in 2016-17 were mainly due to:[207]
  - reduced firm capacity, in particular the closure of Northern Power Station changed the region's generation mix, increasing the dependence on higher-cost gas-fired generators
  - higher prices across the NEM, due to tightening of supply, exacerbated by the retirement of Hazelwood Power Station in Victoria in early 2017
  - exposure of gas-fired generators to higher gas prices. Adelaide spot gas prices increased in the past year from an average ex-ante price of $5.74/GJ in 2016 to $8.83/GJ in 2017.
- In June 2017, the Queensland Government instructed Stanwell Corporation to change its bidding practices, this is likely to place downward pressure on prices.

3.5.1 High prices

Wholesale market

The number of wholesale price spikes in the NEM increased significantly in 2016/17 relative to the five previous financial years.

Figure 3.18 shows a count of trading intervals where the spot price has been above 25 per cent of the market price cap since 2007/08.[208] 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.[209]

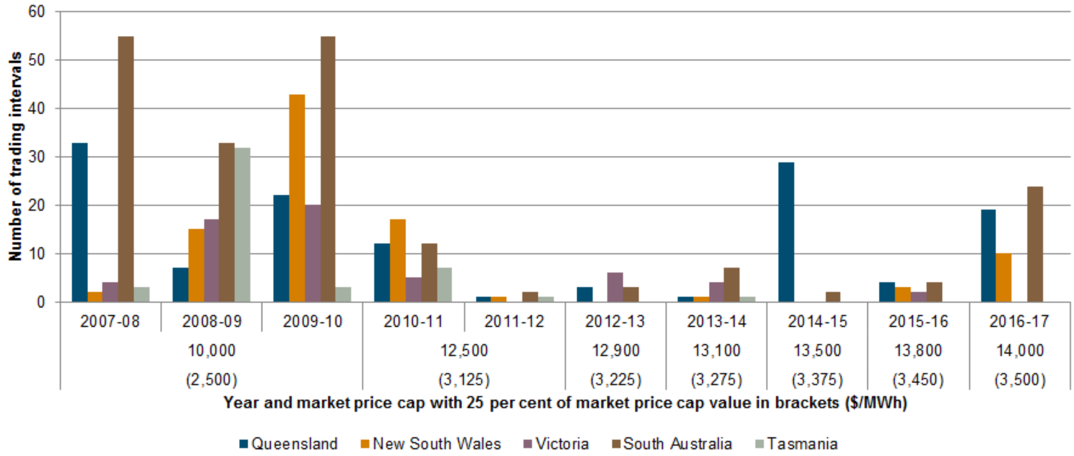
(14,764MW). AER, *Wholesale Statistics - Seasonal peak demand (region)*, accessed 11 December 2017 at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/seasonal-peak-demand-region.

207 AEMO, *South Australian Electricity Report*, November 2017, p. 41

208 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 14,000/MWh in 2016/17.

209 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.

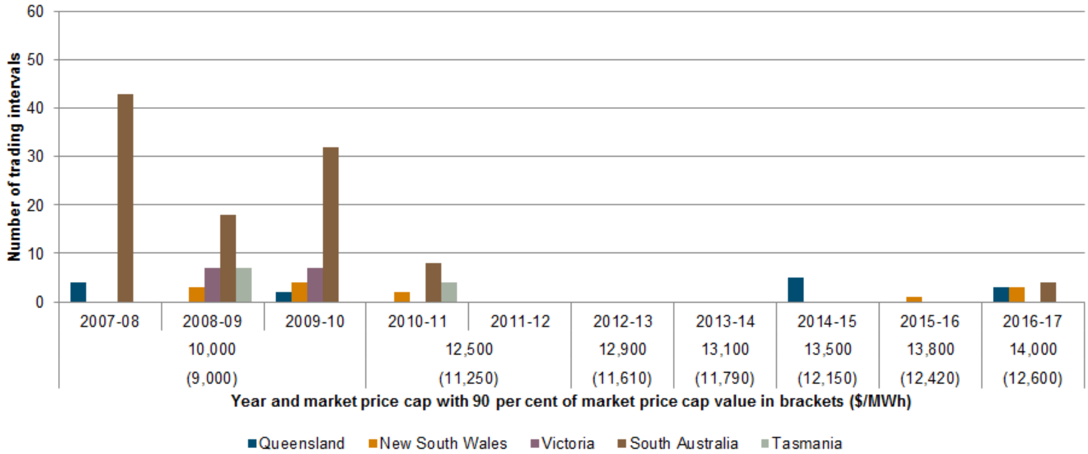
Figure 3.18 Count of trading intervals where the spot price was above 25 per cent of the market price cap



Source: AEMC analysis of Neopoint database

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. This is reinforced by Figure 3.19, 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.

Figure 3.19 Count of trading intervals where the spot price was above 90 per cent of the MPC



Source: AEMC analysis of Neopoint database

In Queensland, New South Wales and South Australia, there has been an increase in the number of trading intervals where prices have been above 25 per cent and 90 per cent of the market price cap in 2016/17 relative to the previous five financial years.[210] The Panel notes that across the NEM, between 2007/08 and 2010/11, more price spikes were observed than in 2016/17.

More detail on high prices events in 2016/17 is provided in appendix I.

210 With the exception of Queensland in 2014/15.

Frequency control ancillary services

Ancillary services under clause 3.11.1 of the rules are 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.[211] These services are generally referred to as frequency control ancillary services (FCAS).
- **Non-market ancillary services:** provide (black) system restart and network support (e.g. voltage control) services, and are provided by parties under bilateral contracts with AEMO, or in the case of network support and control ancillary services (NSCAS), transmission network service providers.

Figure 3.20 shows that the cost of delivery of market ancillary services in the NEM has increased significantly over recent years, from roughly $25 million in 2012 to around $160 million in 2017. Much of this cost increase has been driven by high FCAS prices in South Australia.[212]

The Panel notes that a reduction in the availability of FCAS may be linked to the withdrawal of synchronous generation, which is typically operated in a way that allows it to offer capacity into FCAS markets.[213] If this trend continues it may create security implications for the NEM, particularly as increasing variability of supply and demand is likely to be met with increased frequency control requirements from the market.

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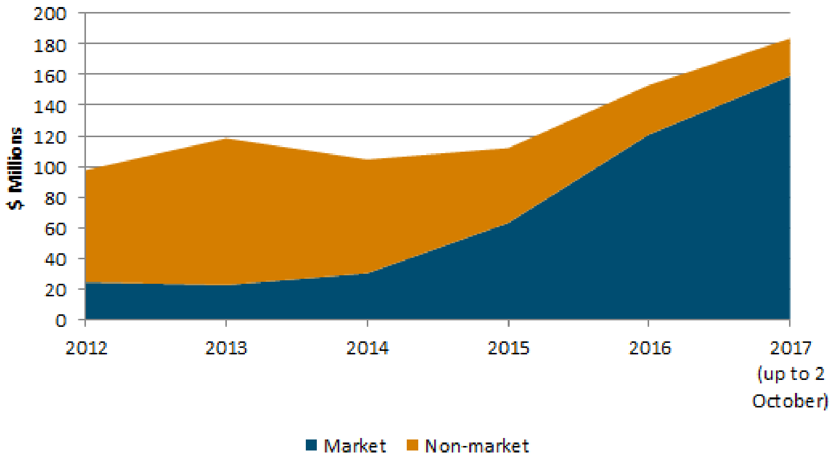
211 AEMO operates the wholesale electricity market, which dispatches electricity generation to meet the expected demand for electricity every five minutes. Some imbalance between supply and demand is expected to occur within the five minute dispatch process which can cause frequency variations. AEMO procures market ancillary services to increase or decrease active power over a timeframe that satisfies the frequency operating standard. For further detail refer to: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services

212 In 2016/17 a major cause of high FCAS prices in South Australia was generators rebidding into a higher price band following an outage on one of the two Heywood interconnector lines. An outage on one of the Heywood lines means there is an increased risk of South Australia separating from the NEM, and the loss of Heywood interconnector is a credible contingency. This means that FCAS must be procured locally (35MW of lower regulation and 35MW of raise regulation). The closure of Northern Power Station in May 2016 also removed up to 72MW in ancillary services from South Australia. In 2016/17 only four power stations in South Australia were registered to provide FCAS: Osborne, Quarantine, Pelican Point and Torrens Island. AER, *AER reports on high ancillary services prices in South Australia from November 2016 to May 2017*, 1 September 2017, accessed 19 February 2018 at: https://www.aer.gov.au/communication/aer-reports-on-high-ancillary-services-prices-in-south-australia-from-november-2016-to-may-2017

213 The market has historically attracted FCAS from synchronous generation. The Panel notes that non-synchronous generation entered the FCAS market for the first time in late 2017. The Hornsdale Power Reserve and Hornsdale Wind Farm are providing ancillary services in South Australia. This will be discussed in greater detail in 2018 AMPR.

Figure 3.20 Cost of ancillary services since 2012



Source: Data taken from AEMO, *Ancillary services payments and recovery*, October 2017

4 Reliability review

This chapter describes:

- the Panel's consideration of the reliability performance of the NEM in 2016/17
- major reliability incidents in the NEM in 2016/17
- 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:** In 2016/17, at the wholesale level, unserved energy of 0.00036 per cent from events which the rules define as reliability events was recorded in South Australia. This is within the reliability standard (an expectation that no more than 0.002 per cent of demand for energy will be unmet). At the wholesale level, no unserved energy was recorded in any other NEM region.[214] 2016/17 was the first year unserved energy was recorded, in any region, since 2008/09.
- **Lack of reserve (LOR) notices:** In 2016/17 there were 22 LOR notices issued, this is the most LOR notices issued since 2009/10. Two LOR3 notices were issued in 2016/17, this was the first time an LOR3 notice had been issued since 2008/09.
- **Directions:** In 2016/17 there were two power system directions issued by AEMO to market participants to maintain the power system in a reliable operating state.[215]

From the perspective of reliability, 2016/17 was a unique year:

- Unserved energy, at a wholesale level, was recorded for the first time in any region since 2008/09.
- LOR3 notices, indicating that load is either being shed, or load shedding is imminent, were issued for the first time since 2008/09.
- There was a significant reliability incident with contributing factors including: extremely high demand, inaccuracies in forecasting generation and load patterns, and outages or output limitations of ageing thermal plant. For this incident, load shedding was exacerbated by the failure of network equipment.

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214 The Panel notes that the following events did not satisfy the rules definition of unserved energy (clause 3.9.3C) and have been excluded by AEMO from unserved energy calculations: (i) 28 September 2016, South Australian black system event; (ii) 1st December 2016, Separation of South Australia, loss of Alcoa Portland supply, the operation of under frequency load shedding in South Australia and direction issued to ElectraNet to reduce load at BHP Billiton's Olympic Dam site by 45MW reduce requirement for fast lower frequency control ancillary service (L6 FCAS); (iii) 10 February 2017, load reduction at Tomago smelter in New South Wales; and (iv) the trip of Basslink and loss of 383MW of industrial load due to under frequency load shedding on 12 March 2017.

215 The Panel notes that power system incidents that arise as a result of insufficient generation, bulk transfer capacity or demand response i.e. incidents that involve the reliability of the system, may lead to directions being issued by AEMO to maintain the power system in a secure operating state. For example, the reliability event on 8 February 2017 in South Australia led to power system directions being issued by AEMO to maintain the power system in a secure operating state.

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 have been used to assess the reliability of the NEM:

- 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.[216]
- 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.[217] In simple terms, reserves can be thought of as the amount of resources that are available to supply the market, but that are not required to be used to meet demand at that point in time but may be required if demand or supply changes (for example due to generation equipment failure).
- Directions: AEMO has the power to issue both directions and instructions 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 rules specify high-level conditions under which AEMO can issue a direction or instruction: (i) if there has been a failure of the market to deliver sufficient reserves or (ii) if the secure and safe operation of the system is under threat.[218] AEMO may also issue directions or instructions if it is satisfied that it is necessary to do so for reasons of public safety or to maintain power system security under section 116 of the NEL.

As in previous AMPRs, these indicators have been examined to demonstrate the overall reliability of the NEM.

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216 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.

217 Reserve levels 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.

218 Directions are issued when AEMO requires a registered participant to take action for the reasons listed in relation to scheduled plant or a market generating unit (i.e. plants with controllable output). For example, AEMO can direct a scheduled plant to reduce load or a generator to increase production. Instructions are issued when AEMO requires a registered participant to take some other action for the above reasons. For example, a clause 4.8.9 instruction to a network service provider to disconnect load.

4.1.1 The reliability standard and unserved energy

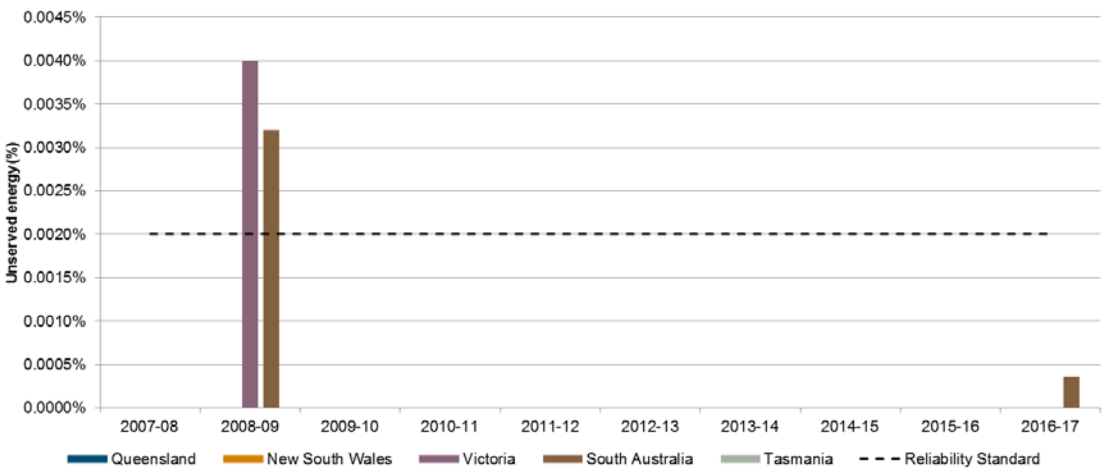
The reliability standard is focussed on the wholesale market and is the maximum expected unserved energy in a region for a given financial year.[219]

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.

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.[220]

Historically, at a wholesale level, there has been very little unserved energy in the NEM. Figure 4.1 compares the reliability performance of each region in terms of unserved energy over the past decade. 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

In 2016/17, at a wholesale level, unserved energy of 0.00036 per cent was recorded in South Australia. This is within the reliability standard (an expectation that no more than 0.002 per cent of demand for energy will be unmet). An incident on 8 February 2017 (described below) was the sole contributing event to unserved energy in South Australia.

219 Rules clause 3.9.3C.

220 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. 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.

At a wholesale level, no unserved energy occurred in any other NEM region.[221] From the perspective of the wholesale market, unserved energy last occurred in the NEM in 2008/09.[222]

8 February 2017, unserved energy in South Australia

Demand and supply from renewable and thermal generation were changing rapidly in the period just prior to a loss of system security. At approximately 6.00pm:

- demand was higher than forecast
- wind generation was lower than forecast, and
- thermal generation capacity was reduced due to forced outages.

Pelican Point notified AEMO that 165MW of capacity was unavailable. 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. Load shedding (100MW, for 27 minutes) then became the only available option for AEMO to restore system security.[223]

This event is described in detail in section 4.2

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, non-reliability related circumstances and events that may cause an interruption to consumer supply. These include:

- distribution network outages
- transmission network outages, in the non-bulk transmission sections of the transmission network (i.e., parts of the transmission network other than interconnectors)

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221 The Panel notes that the following events did not satisfy the rules definition of unserved energy (clause 3.9.3C) and have been excluded by AEMO from unserved energy calculations: (i) 28 September 2016, South Australian black system event; (ii) 1st December 2016, Separation of South Australia, loss of Alcoa Portland supply, the operation of under frequency load shedding in South Australia and direction issued to ElectraNet to reduce load at BHP Billiton's Olympic Dam site by 45MW reduce requirement for fast lower frequency control ancillary service (L6 FCAS); (iii) 10 February 2017, load reduction at Tomago smelter in New South Wales; and (iv) the trip of Basslink and loss of 383MW of industrial load due to under frequency load shedding on 12 March 2017.

222 Unserved energy occurred in Victoria and South Australia during 29 and 30 January 2009 as extreme temperatures gave rise to very high demand. There were also short notice reductions in the availability of Basslink and progressive reductions in the availability of a number of Victorian generators at short notice on both days. AEMC Reliability Panel, *Annual market performance review 2008-09, final report*, December 2009, p. 5.

223 AEMO, *System Event Report South Australia, 8 February 2017*, 15 February 2017. In South Australia 100MW of load was shed for 27 minutes as a result of this event. The Panel notes that actual load shedding by the local network operator was approximately 300MW, this additional 200MW was not included in the unserved energy calculations as this is load that the system was able to support.

- imbalances in generation and demand triggered by shortages in generation capacity due to a non-credible contingency.[224]

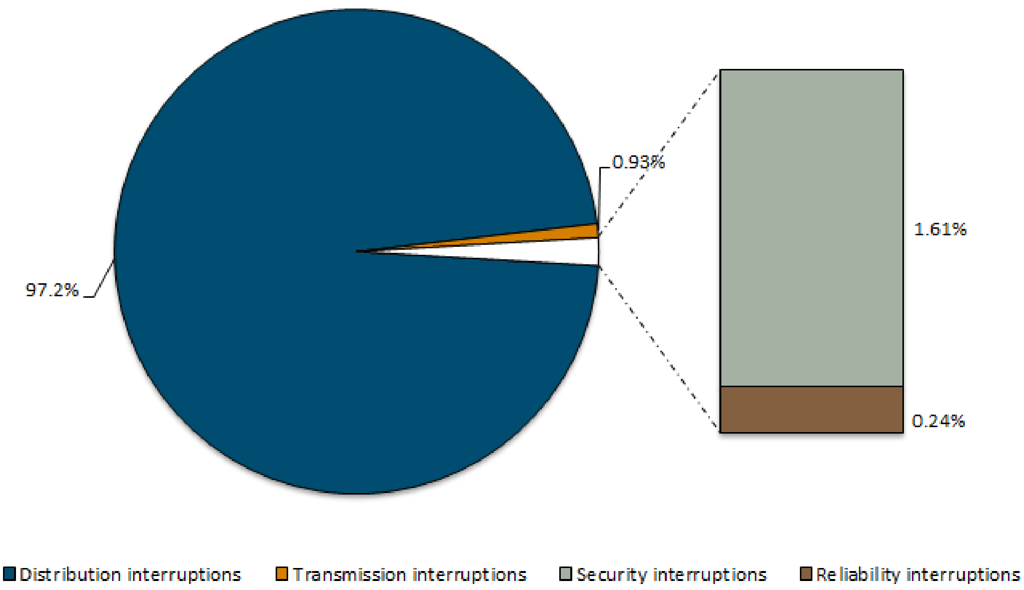
Non-credible contingencies may result in large disturbances to power system security, including large deviations in system frequency from the normal operating frequency of the NEM. These large deviations may trigger automatic protection systems known as under frequency load shedding schemes, which shed 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. Under frequency load shedding schemes are discussed in more detail in section 5.1.2.

Figure 4.2 shows the interruptions of supply arising from incidents involving reliability, security, transmission networks and distribution networks from 2007/08 to 2015/16. The Panel notes that interruptions to consumer supply relating to the reliability of generators and interconnectors have historically represented a small amount of all supply interruptions experienced by customers. Over the period, only about 0.24 per cent of total supply interruptions (in terms of GWh) were the result of reliability events (brown area of chart). Security events also represented a small portion (grey area) of all supply interruptions, 1.61 per cent. Estimates show that the distribution network is responsible for about 97 per cent of supply interruptions (blue area of chart). The distribution network represents the largest infrastructure in the electricity supply chain, with many possible points of failure. Standards relating to distribution networks are set by jurisdictions.[225] 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.

224 Any planned or forced outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.

225 See appendix B for more information

Figure 4.2 Sources of supply interruptions in the NEM



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

4.1.2 Reserve levels

Reserve levels refer to the amount of spare capacity available given amounts of generation, forecast demand and demand response, and scheduled network service provider capability (specifically interconnectors) at any point in time.[226] A reserve level indicates the difference between available resources to meet demand for energy, and the level of energy demanded. Reserves acts as a buffer to help manage unexpected system developments such as the loss of a large generator.

On 19 December 2017, the Commission made a rule to modify the original framework for the declaration of lack of reserve (LOR) conditions.[227] The new framework removes the deterministic descriptions of lack of reserve from the rules and replaces them with a single high-level definition for lack of reserve, as well as a requirement for AEMO to make guidelines that set out how it will determine, at least three, lack of reserve conditions.[228] The new framework will better capture the risks of involuntary load shedding, as well as promote more efficient market responses to potential shortfalls in the short-term.

Under the original framework which had existed since the start of the NEM, there were three different lack of reserve conditions in the NEM. AEMO issued declarations that

226 Reserves are defined in chapter 10 of the rules.

227 The *Declaration of lack of reserve conditions* rule is detailed in section 4.4.4. The transitional rule commenced on 19 December 2017 and the remaining schedules commenced on 16 January 2018.

228 Lack of reserve conditions are defined in the new framework as: "when AEMO determines, in accordance with the reserve level declaration guidelines, that the probability of load shedding (other than the reduction or disconnection of interruptible load) is, or is forecast to be, more than remote."

these conditions exist, in order to signal to the market there was either a present or potential future shortage of reserve:[229]

- Lack of reserve level 1 (LOR1): this meant that two successive credible contingencies, such as the loss of the two largest generating units, could result in there being insufficient supply to meet demand.
- Lack of reserve level 2 (LOR2): this meant that a credible contingency, such as the loss of the largest generating unit, could result in there being insufficient supply to meet demand.
- Lack of reserve 3 (LOR3): this meant that there is insufficient supply to meet demand. An actual LOR3 represented load shedding.

A LOR3 indicated a significant impact on the NEM, as it indicated that load was either being shed, or load shedding was imminent. A LOR1 had a less significant impact on the NEM as it meant that load shedding was still only likely to occur following a multiple contingency.

Under the new framework, AEMO will still declare three LOR levels, according to its reserve level declaration guidelines. In fact, LOR3 has remained unchanged. While LOR1 and LOR2 definitions have been adjusted, AEMO still intends for the definitions to reflect, at a minimum, the risks associated with credible contingency events.

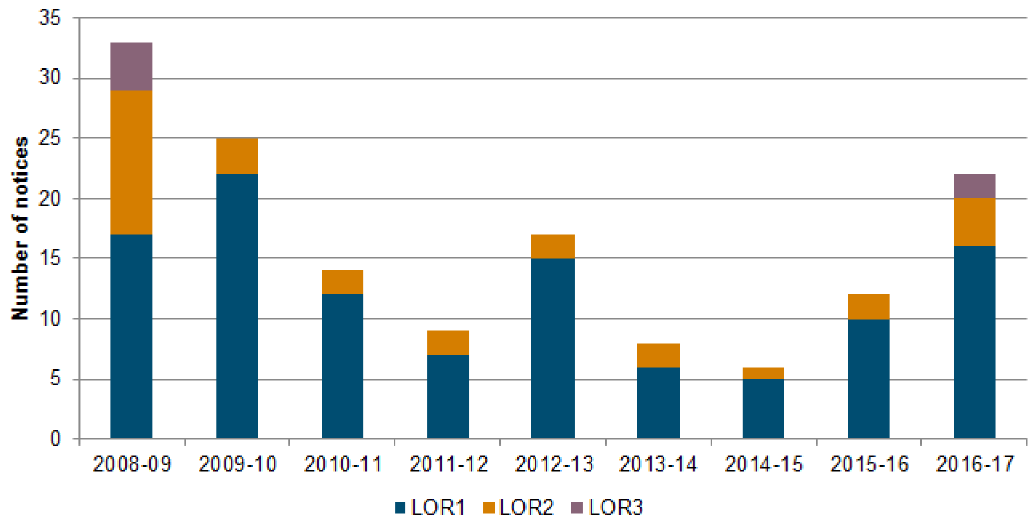
Figure 4.3 shows the number of LOR notices issued in the NEM since 2008/09. Across the NEM the Panel notes:

- In 2016/17, there were 22 LOR notices issued. This is the highest number of LOR notices since 2009/10. Over the period considered, the greatest number of notices (33) were issued in 2008/09. This coincided with the only previous instances of unserved energy, at the wholesale level, in the past decade.
- In 2016/17 there were two LOR3 notices issued.[230] This is the first time LOR3 notices were issued since 2008/09.
- Prior to 2016/17 there was a gradual decline in the number of LORs issued by AEMO.

229 The three conditions were, under the original framework, defined in Chapter 4 of the rules.

230 LOR3 notices were issued on 8 February 2017 in South Australia and 10 February 2017 in New South Wales.

Figure 4.3 LOR notices issued in the NEM[231]



Source: AEMO

Changing reserve levels may be relevant to the risk of unserved energy in a region. A narrower reserve margin may indicate that there is a greater risk of demand outstripping supply, which could in turn potentially result in unserved energy. Conversely, if the amount of generation reserve available increases, the risk of unserved energy occurring may decrease.[232]

Unserved energy can occur under a number of circumstances and the increase in LOR notices in 2016/17 should be taken only as a general indicator; it is not sufficient in itself to suggest that reliability in the NEM, or in any of the regions, has materially worsened. AEMO has determined a number of variables leading to the increased rate of LOR notices including:

- "short-term grid demand forecast error, particularly during extreme hot weather, which is in turn affected by surprisingly small errors in weather forecasts
- short-term large-scale wind and large-scale solar generation forecast error
- widespread partial availability reductions in thermal generation during stressful ambient conditions
- variations in network constraints."[233]

4.1.3 Directions and instructions

Despite the fact that system reliability is based around market-driven investment, retirement and operational decisions, AEMO is provided with powers to intervene in

231 This figure uses the history of market notices of LORs being issued. The count does not exactly match the number of times LOR conditions have existed, but it shows the trend.

232 The Panel notes that there are a number of other factors relevant as to whether unserved may occur, such as the probability of a generating unit or transmission element outage.

233 AEMO, *Letter to the AEMC - Rule change proposal: Lack of Reserve Declaration*, 1 August 2017, accessed at: https://www.aemc.gov.au/sites/default/files/content/f34981af-a794-4836-a576-c090966d5804/Rule-change-request.pdf, p. 2.

the market to address potential shortfalls of reserves. AEMO has the power to either issue directions or instructions to market participants as a last resort measure, or to contract for the provision of reserves through the RERT mechanism, in order to maintain power system security and reliability.[234]

During 2016/17 two directions to market participants were issued to maintain the system in a reliable operating state.[235] Both direction events are described below. Eight other directions were issued by AEMO in 2016/17 to maintain the power system in a secure operating state. These are discussed in section 5.1.7.

South Australia, 9 February 2017

At 3.05pm AEMO issued a direction to ENGIE to synchronise and dispatch Pelican Point unit GT12 to minimum load.[236]

Hot weather (39.4˚C) led to high demand conditions with demand in South Australia peaking at 3,041MW at 6.30pm. Wind generation in South Australia was low, ranging between 182MW and 385MW between 4.00pm and 7.00pm. A forecast LOR2 condition had been declared in the South Australia region for trading intervals between 4.00pm and 6.00pm. A sufficient market response was not received by the latest time to intervene, at 3.00pm. At the same time as the direction to Pelican Point was issued, AEMO issued counter-action instructions to two other gas-fired generators in South Australia. Mintaro gas turbine was instructed to reduce output from 69MW to its minimum load of 30MW, and two of the Dry Creek units were instructed to reduce output from a combined output of 75MW to their combined minimum load of 10MW. The aim of this counter-action was to minimise the market impact of the direction, as required by clauses 3.8.1(b) and 4.8.9(h)(3) of the rules.[237]

Intervention pricing was implemented for this event, and so, financial settlements were based on the price outcomes from the intervention pricing run.[238] Figure 4.4 gives an indication of the cost associated with this direction, with the intervention pricing run spot price materially higher than the dispatch spot price in South Australia.

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234 Directions or instructions may be issued by AEMO if: (i) there has been a failure of the market to deliver sufficient reserves; (ii) the secure operation of the system is under threat. Directions are issued when AEMO requires a registered participant to take action for either of these two reasons in relation to scheduled plant or a market generating unit (i.e. plants with controllable output). Instructions are issued when AEMO requires a registered participant to take some other action for the same aforementioned reasons. For instance, AEMO can *direct* a generator to increase production or *instruct* a network service provider to disconnect load. Refer to rules clause 4.8.9 on AEMO's power to issue directions and instructions. Refer to rules clause 3.20.7(a) on AEMO's RERT powers.

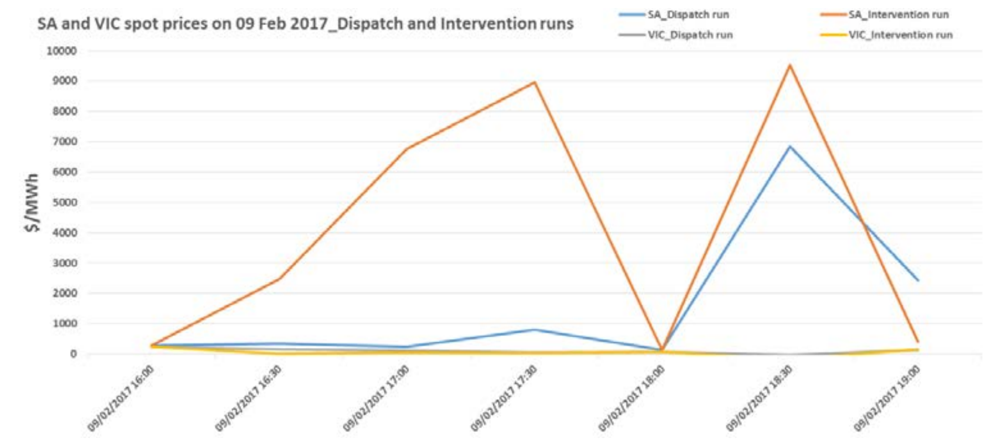
235 No directions were issued to maintain the system in a reliable operating state in 2015/16.

236 AEMO, *NEM Event - Direction to South Australia Generator, 9 February 2017*, July 2017.

237 Although the reduction in generation due to counter-action was similar to the increased generation due to the direction, it had the advantage of ensuring generation availability from five generating units (Pelican Point GT11, Pelican Point GT12, Mintaro, Two Dry Creek units), with their additional generation capacity (from their minimum load to maximum capacity) being available to meet the increasing demand. This additional capacity was sufficient to alleviate the LOR2 condition.

238 Intervention pricing is intended to preserve the market signals that would have existed had the intervention not taken place, and it is used for the purposes of spot price determination and settlements. Intervention pricing run is a parallel NEMDE run to the dispatch run to determine the intervention prices (in realtime) in accordance with the intervention pricing methodology.

Figure 4.4 Dispatch and Intervention runs - South Australia and Victoria, 9 February



Source: AEMO, *NEM Event - Direction to South Australia Generator, 9 February 2017*, July 2017, p. 15.

South Australia, 1 March 2017

At 4.39pm AEMO issued a direction to Pelican Point unit GT12 to run at minimum load.[239]

From 9.30am onwards AEMO issued multiple notices advising the market of forecast LOR1 conditions for the evening peak in South Australia. AEMO issued an actual LOR1 notice at 3.30pm.

The direction to Pelican Point GT12 was issued following an assessment of potential reserve shortfalls based on increasing risk factors, including:

- Reclassification of the simultaneous loss of Quarantine Power Station units 1, 2, 3, and 4 due to gas pressure issues.
- Significant wind generation forecast uncertainty.
- High South Australian demand forecast coinciding with hot weather conditions, with increased forecast uncertainty at those temperatures.[240]
- Elevated risk of generation performance issues during hot weather conditions.
- Lack of available options to ensure power system reliability (up to load shedding) should a credible contingency event occur.
- The notice period required in respect of the only unit available for direction.

After assessing these factors, AEMO considered that it may not have been able to avoid the need for load shedding if a credible contingency event occurred. By the time this conclusion was reached, the latest time to intervene was already imminent based on the lead time of the only available unit for a direction (Pelican Point GT12).[241] Accordingly,

239 AEMO, *NEM Event – Direction to South Australia Generator, 1 March 2017*, January 2018.

240 Hot weather (38.6˚C) led to high demand conditions with demand in South Australia peaking at 2,727MW at 5.30pm.

241 The notified lead time for Pelican Point GT 12 is 1.5 hours.

AEMO decided to issue a direction to Pelican Point GT12 for the maintenance of power system reliability.[242]

At 6.25pm the LOR1 condition ceased. At 7.25pm the direction was cancelled when the supply-demand balance was alleviated and potential lack of reserve conditions did not eventuate because of higher than expected wind output.

AEMO notes the AEMC's recent *Declaration of lack of reserve conditions* rule change will allow the uncertainties listed above to be reflected in the reserve level declarations, providing additional transparency to the market.[243]

Use of the Reliability and emergency reserve trader (RERT) mechanism

The RERT is a mechanism in the NEM which allows AEMO to contract for reserves (generation or demand-side capacity that is not otherwise being traded in the market), that it can use in the event that it projects that the market will not meet the reliability standard (that is, 0.002 per cent expected unserved energy) and, where practicable, to maintain power system security. The RERT can therefore be considered a form of strategic reserve. Currently, there are two types of RERT based on how much time AEMO has to procure the RERT prior to the shortfalls occurring:[244]

- medium-notice RERT - between ten 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.[245]

No reserve contracts were entered into for 2016/17 period. The Panel notes that AEMO released tenders for the RERT in July 2017 and again in September 2017 for summer 2017/18.[246] A total of 1,150MW (884MW of demand response and 266MW of generation) was made available under the RERT for summer 2017/18. The RERT was activated twice in Victoria, on 30 November 2017 and 19 January 2018, to maintain the

242 Pelican Point GT12 synchronised at 5.32pm but was unable to follow dispatch targets to minimum load due to a trip of Pelican Point ST18 at 5.42pm. In order for GT11 and GT12 to come up to minimum load, ENGIE advised the AEMO control room that Pelican Point Power Station would need to reduce total output to approximately 27MW for ST18 to re-start (below original availability of 220MW). Both GT11 and GT12 increased to minimum load of 160MW each at around 1905 hrs. Information on the costs associated with this direction is not publicly available. The Panel notes a relatively small amount of additional generation (50.37MWh) was dispatched as a result of the direction.

243 The *Declaration of lack of reserve conditions* rule change is discussed in section 4.4.4.

244 Prior to 1 November 2017, AEMO was able to use the long-notice RERT to procure reserves up to nine months ahead of a shortfall. The long-notice RERT was removed to increase the timeframe over which the market can respond to a projected reserve shortfall, before AEMO enters into RERT contracts. AEMC, *Extension of the Reliability and Emergency Reserve Trader, rule determination,* June 2016, p. i.

245 AEMO has the discretion to use a tender process in addition to using panel members in the case of the medium-notice RERT.

246 AEMO used the long-notice RERT to procure these reserves.

power system in a reliable operating state.[247] In both instances reserves were dispatched for six hours. Prior to these events the RERT had only been procured three times, and had never been dispatched. These events will be discussed in greater detail in AMPR 2018.

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. The following incident contributed to unserved energy, at a wholesale level, in 2016/17:

- 8 February 2017, load shedding in South Australia

In reporting this event the Panel has focussed on key themes including:

- inaccuracies in forecasting the variability of supply and demand
- outages of thermal generators and the unexpected failure of equipment

The commentary below draws heavily from AEMO's incident report.

4.2.1 8 February 2017, South Australia

On 8 February 2017 load shedding occurred in South Australia. The incident involved:[248]

- Rapidly changing demand and supply from renewable and thermal generation in the period just prior to a loss of system security. At the point in time where demand was at its highest level during the day:
  - demand was higher than forecast
  - wind generation was lower than forecast, and
  - thermal generation capacity was reduced due to forced outages.
- The unavailability of 165MW of Pelican Point 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.
- A direction from AEMO to ElectraNet to shed 100MW of load with clearance given to restore that load 27 minutes later. This was the only available option to restore system security requirements.[249] Actual load shedding by the local network operator was approximately 300MW.[250]

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247 AEMO, *Market Notice - RERT activated*, 30 November 2017.

248 AEMO, *System event report South Australia*, 8 February 2017, 15 February 2017.

249 The Panel notes that if stress on the system stemming from reliability incidents is not alleviated early enough it will often result in directions being issued for system security.

250 An issue with SA Power Networks' load shedding software meant that an additional 60,000 customers had their load shed. SA Power Networks, *Statement re load shedding event (8 February 2017)*, 15 February 2017, p. 1.

Key details

1. At 3.00pm, pre-dispatch Projected Assessment of System Adequacy indicated a forecast LOR1 for the South Australian region from 4.30pm to 7.00pm.
2. At 5.25pm, a constraint managing the flow on Murraylink was violated. Murraylink's flow exceeded its limit of 78MW by over 100MW. The power system was therefore not in a secure operating state.
3. At 6.03pm, AEMO declared an LOR3 condition for the South Australia region and issued a direction to ElectraNet to reduce load by 100MW to reduce the flow on Murraylink and restore system security.
4. At 6.20pm, the market price cap was applied in South Australia from the dispatch interval ending 6.25pm.
5. At 6.30pm, AEMO advised ElectraNet to start restoring load.
6. At 6.50pm, the market price cap pricing was removed and at 7.00pm the LOR3 condition was cancelled.

Of the installed operational capacity in South Australia of 5,157MW, a total of 3,046MW was available at 6.00pm on 8 February to contribute to the operational peak demand of 3,085MW. The shortfall meant that Heywood's operating limits were being breached.[251]

There are three key issues relevant to the 8 February 2016 event, including:

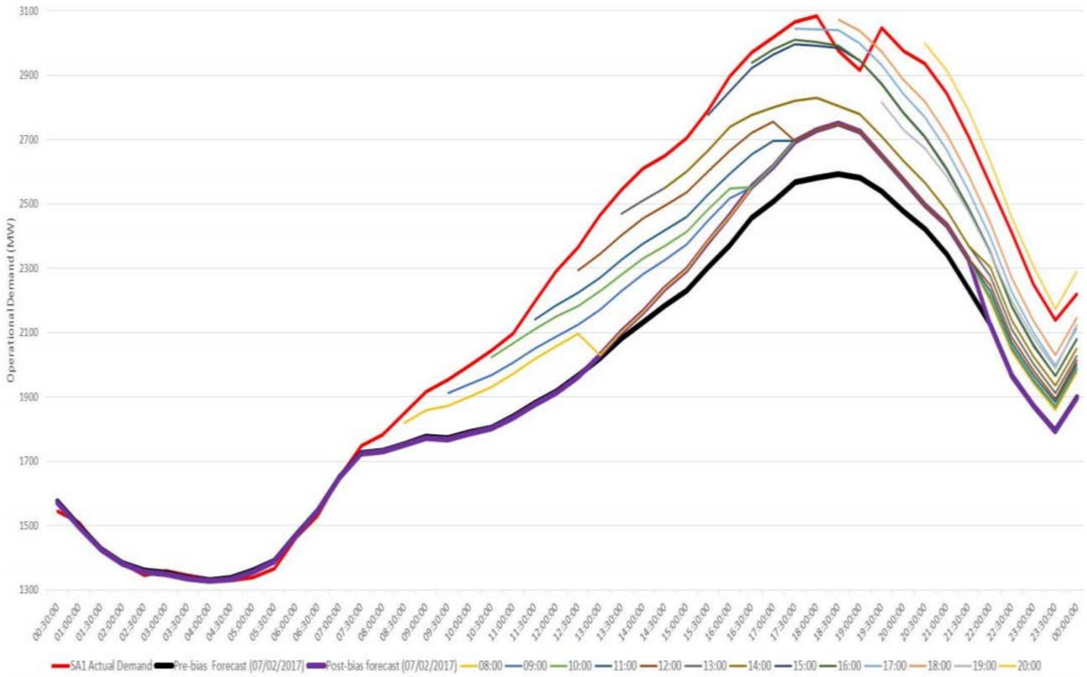
- demand being higher than forecast
- wind generation decreasing more rapidly than forecast
- several thermal outages, including several pre-existing and forced outages.

Demand forecasts

Figure 4.5 shows that throughout the day demand (indicated by the red line in chart) was higher than forecast, with the exception of a window between 6.30pm and 7.30pm.

251 To relieve interconnector limits, demand must be reduced or supply must be increased.

Figure 4.5 South Australia operational demand, forecast and actual, 8 February



Source: AEMO, *System event report South Australia*, 8 February 2017, 15 February 2017

Wind generation forecasts

The actual wind generation matched the forecast up to 4.00pm. From 4.00pm onwards, actual wind generation declined more rapidly than forecast, as a result of a sharp drop in wind speed between 4.00pm and 6.00pm. As a result:

- the forecast issued at 2.00pm was for about 175MW of wind generation for the trading interval ending at 6.30pm.
- the forecast issued at 4.00pm was for about 200MW of wind generation for the same trading interval.
- At 6.00pm, the actual wind generation was about 100MW and falling.

Thermal outages

Thermal generation in South Australia is generation from gas-fired or diesel-fired generating units. At 6.00pm on 8 February 2017, when load shedding commenced, all thermal generating units in South Australia were on line and operating at or near full capacity, except for those shown in Table 4.1 and Table 4.2.

Table 4.1 Pre-existing outages of thermal generation

Generating unit	Normal capacity	Actual capacity	Bid status	Reason
Torrens island A1	120MW	0MW	Declared unavailable ahead of the day	Long term outage: boiler tube leak
Pelican Point Gas Turbine 12	165MW	0MW	Unavailable	Market participant bid

Generating unit	Normal capacity	Actual capacity	Bid status	Reason
				as unavailable; confirmed unavailable at 5.39pm with minimum start time of four hours
Total capacity unavailable = 285MW				

Table 4.2 Forced outages of thermal generation on 8 February 2017

Generating unit	Normal capacity	Actual capacity	Bid status	Reason
Torrens Island B1	200MW	150MW	Available	Market participant reduced capacity bid at 5.42pm on 8 February due to high ambient temperatures
Torrens Island B4	200MW	190MW	Available	
Quarantine 4	20MW	0MW	Unavailable	Market participant bid unavailable at 5.18pm on 8 February
Port Lincoln 1	50MW	0MW	Unavailable	Market participant bid unavailable at 4.07pm on 8 February as a result of a control signal fault, caused by failure of electronics in the communications system.
Port Lincoln 3	23MW	0MW	Unavailable	
Total capacity reduction after 4.00pm on 8 February = 153MW				

Costs associated with the incident

SA Power Networks were instructed to shed 100MW of load equivalent to 30,000 households. Supply was interrupted to a further 60,000 households due to an issue with SA Power Networks' load shedding software.[252] Direct costs associated with this event have not been published. In 2014, AEMO estimated a value of customer reliability of

252 SA Power Networks, *Statement re load shedding event (8 February 2017)*, 15 February 2017, p. 1.

$26.88/kWh for South Australian residential customers.[253] Based on this figure the costs incurred were approximately 8.7 million dollars. This provides a useful indication of the upper bound on costs incurred as a result of this event.

4.2.2 Key themes

Accuracy of forecasts of demand and generation

The Panel acknowledges that accurately forecasting electricity demand and intermittent generation is challenging. The increased uptake of variable intermittent generation capacity adds further complexity to the forecasting process. Inaccuracies in forecasts played a critical role in the 8 February 2017 incident. The Panel notes the following commentary on the event.

ERM Power, in its submission to the Panel's *Reliability standard and settings review*, expressed the view that the 8 February 2017 load shedding event was not due to a shortfall in generation:[254]

> "The 16:00 predispatch revision indicated a higher level of output from wind farms located in South Australia and a lower level of forecast demand for South Australia. Combined, these errors totalled approximately 250 MW when compared to actual outcomes. Had AEMO's forecasts been more accurate at the 16:00 revision, this involuntary load shedding event may well have been avoided as the LOR2 notice would have been issued one hour earlier than actually occurred [providing sufficient time for the second Pelican Point generator unit to return to service]."

The Australian Energy Regulator also echoed this point on forecast inaccuracies:[255]

> "More accurate forecasts of both demand and wind generation may have led to earlier market signalling of a shortage"

The Panel notes AEMO has regularly refined its demand forecasting methodology. In 2018 demand forecasting improvements will involve AEMO studying historical detailed meter data to observe consumption patterns down to individual consumer segments, as part of a broader analytics program,.[256] A full description of improvements made to AEMO's forecasting methodology is described in appendix D. The AEMC is also considering the importance of forecasting processes for reliability through the *Reliability Frameworks review*.[257]

Thermal generator outages

Outages of thermal generators were a key contributing factor to the reliability event that occurred on 8 February 2017.

253 AEMO, *Value of customer reliability review, final report*, September 2014, p. 8.

254 *ERM Power submission to the reliability standard and settings review*,18 July 2017, p. 3-4.

255 AER, *AER reports on 8–9 February high wholesale electricity prices in South Australia and New South Wales*, 27 April 2017

256 AEMO, *Forecast accuracy report*, November 2017, p. 12.

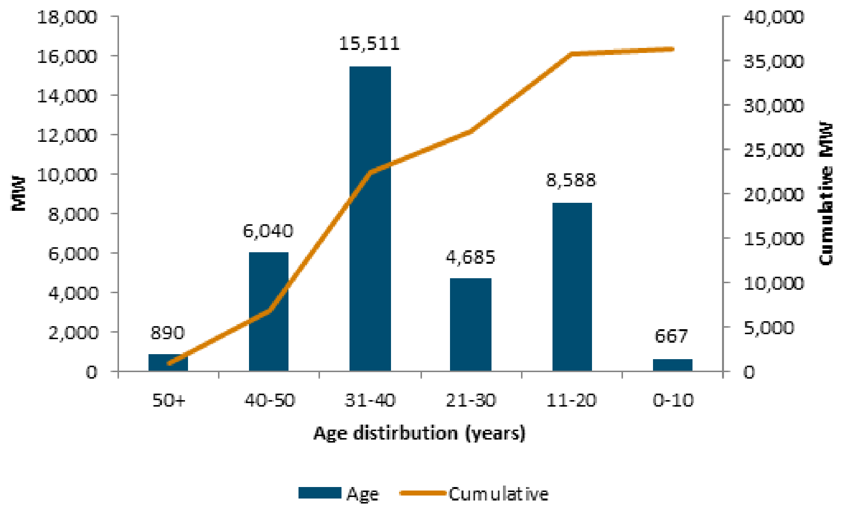
257 For more information see: http://www.aemc.gov.au/getattachment/888511f5-9f89-4af2-8803-6302b53636f4/Interim-report.aspx

Many thermal power stations in the NEM have capacities over 1000MW and so the unexpected trip of just a few units can immediately place stress on the system, especially at times of high demand.

On 8 February 2017, the Torrens Island A1 and Pelican Point Gas Turbine 12 units were unavailable due to pre-existing outages. Together they represent 285MW of capacity. A further 153MW of thermal capacity was unavailable due to forced outages.[258] These outages represented 17 per cent of South Australia's gas powered generation capacity.

Figure 4.6 shows that some of the NEM's thermal generators have been in service for over 40 years. This may mean outages, either forced or unforced (due to maintenance), of these ageing units become more common, particularly for those units that are past their technical operating lifespan.

Figure 4.6 Age distribution of thermal plant



Source: AEMC analysis

The Panel also notes that 8 February 2017 event occurred during an extreme heat wave. Roughly 60 per cent of the generating capacity in the NEM depends on water for cooling.[259] In heatwaves, cooling becomes difficult and as evidenced, many power stations fail to produce at their full capacity.[260]

Equipment failure

The Panel notes equipment failure may exacerbate the effects of reliability events. On 8 February 2017, an error with load shedding software meant than an additional 60,000 households had supply interrupted. This was in addition to the amount of load that needed to be shed

258 Refer to Table 4.2 for more details.

259 Based on a figure from Smart and Aspinall, *Water and the electricity generation industry*, 2009

260 The Australia Institute, *Can't stand the heat - The energy security risk of Australia's reliance on coal and gas generators in an era of increasing heatwaves*, November 2017, p. 15.

4.3 Reliability projections

For the 2017 AMPR, the Panel has used two separate projections of unserved energy, at a wholesale level:

- AEMO's 2017 *Electricity statement of opportunities* (ESOO) projections from 2017/18 to 2026/27. The ESOO is an annual report that provides technical and market data relating to opportunities in the NEM over a 10 year outlook period. The data presented in the ESOO informs the decision-making processes of market participants, new investors, and jurisdictional bodies.
- Ernst and Young's (EY) projections from 2017/18 to 2023/24, prepared as part of the modelling that informed the Panel's *Reliability standard and settings review 2018*.[261] EY's modelling presented a base case and several scenarios that was used to inform the Panel's consideration of the appropriate levels of the various reliability settings, including the market price cap, cumulative price threshold, administered floor price and market floor price.

The Panel notes that forecasting electricity supply and demand is a complex process. As such, the two sources of unserved energy projections described above differ in a number of ways including their overall purpose, modelling approach, input data, assumptions, and scenarios and sensitivities tested. These have in turn contributed to some differences in terms of the results presented in the two projections.

The key difference is that these two models project different amounts of unserved energy, with AEMO forecasting significantly more unserved energy than EY's projections. However, noting the differences between the two models, the Panel considers that these different projections have value in that they provide a broad view of potential future outcomes in the NEM.

In addition to the different modelling rationales (and accompanying assumptions and sensitivities), EY notes that the majority of the differences between EY's and AEMO's unserved energy forecasts are due to the following factors:[262]

- EY's half-hourly modelling of wind, solar and rooftop PV uses some different assumptions to AEMO. In particular EY uses different data sets that describe the characteristics of wind generation in different regions. This difference in wind resource data means AEMO and EY have different wind generation profiles.
- EY assumes a much greater contribution to peak demand from behind-the-meter storage, which results in lower peaks in the demand to be met by scheduled generators in the NEM, compared to AEMO.

261 The *Reliability standard and settings review* is discussed in detail in section 4.4.3.

262 EY determined these factors from modelling work which will be published in April 2018 and accompany the release of the Panel's final report for the *Reliability standard and settings review 2018.* This modelling work involved EY replicating AEMO's ESOO "dispersed renewables" generation development plan in the EY model. The installed capacity and other assumptions were aligned to the ESOO modelling in order to isolate the reason(s) for the different unserved energy outcomes in EY's and AEMO's modelling. EY then conducted additional sensitivities to that scenario, introducing EY's data sets one by one to isolate the contributions to the unserved energy differential between the ESOO and EY's base scenario for the *Reliability standard and settings review*. EY focused on 2022-23, the year following the assumed retirement of the Liddell power station.

- EY’s dispatch modelling software differs from AEMO’s and as a result, some aspects of the modelling approach are not the same. This factor was the smallest driver of difference between unserved energy projections.

AEMO's projections of gas availability are also presented by the Panel in this section.

4.3.1 AEMO's 2017 ESOO unserved energy forecasts

In September 2017 AEMO published the 2017 ESOO. 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 plant retirements and operational and economic information. In the ESOO, AEMO also provides forecasts of unserved energy for the regions of the NEM for a 10-year period from 2017-18 to 2026-27.

Rationale

Three scenarios are modelled for the ESOO.

The aim of the ESOO **committed capacity scenario** is to provide information about "generating units for which formal commitments have been made for construction or installation".[263] AEMO is required to model this scenario under the rules. The scenario "incorporates all existing generation in the NEM and new generation that meet AEMO’s commitment criteria".[264]

The ESOO also considered two other scenarios with different renewable generation pathways. The aim of these scenarios was to "capture a broad range of possibilities that could occur in the NEM in the next 10 years".[265] The **concentrated renewables scenario** assumes "potential additional development after 2020 is geographically concentrated particularly in Victoria, driven by the Victorian Renewable Energy Target (VRET)".[266] The **dispersed renewables scenario** includes the LRET (as with the concentrated renewables scenario), but further assumes any additional renewable capacity incentivised from 2021 onwards is driven through nationally set (or at least co-ordinated) targets, rather than state-based schemes.[267] Additional renewable capacity is spread across the NEM regions.[268] AEMO also considered a **high demand sensitivity**, which includes demand growth in the upper range of expectations and assumes generation was developed according to the dispersed renewables scenario.

263 Refer to rules clause 3.13.3(q)(2). Note this scenario does not install sufficient capacity to meet the LRET for example.

264 AEMO, *ESOO*, September 2017, p. 7. AEMO's commitment criteria includes the following categories: site, major components, planning consents/construction and connection approvals/EIS, finance and final construction date.

265 AEMO, *ESOO*, p. 7. These two scenarios are not required by the rules.

266 AEMO, *ESOO*, p. 7. According to the ESOO: "[t]he Concentrated renewables pathway’s goal is to deliver renewable capacity from the federal Largescale Renewable Energy Target (LRET) and the VRET [out to 2025] only."

267 No such national target currently exists.

268 For modelling purposes, this pathway targeted 45 per cent renewables by 2029–30, a mid-point of the proposed outcomes announced by the Queensland and Victorian governments.

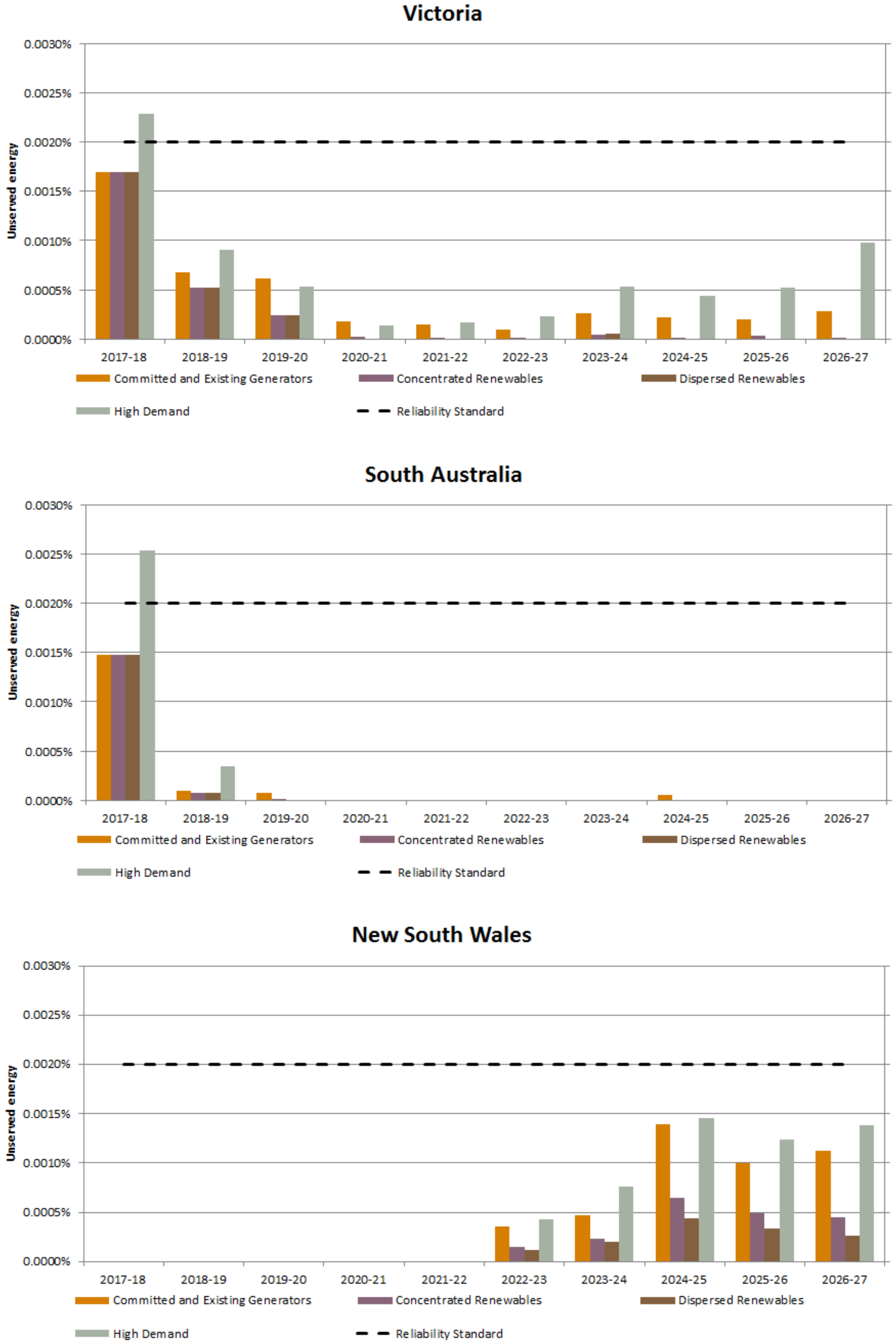
Both the concentrated renewable and the dispersed renewable scenarios include capacity built beyond AEMO's commitment criteria to meet renewable targets, but the model does not assess whether any of this new entrant capacity is commercially viable.

Outcomes

Figure 4.7 shows AEMO's ESOO unserved energy outcomes.[269]

[269] There is no chart for Queensland or Tasmania as no unserved energy is expected in these regions over the modelled timeframe.

Figure 4.7 AEMO's unserved energy projections



Source: Charts prepared using data contained in AEMO's ESOO results spreadsheets[270]

270 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

Key insights highlighted by AEMO in the ESOO include:[271]

- There is a heightened risk that the current NEM reliability standard will not be met, and confirms that for peak summer periods, targeted actions to provide additional firming capability are necessary to reduce risks of supply interruptions.
- The highest forecast unserved energy risk in the 10-year outlook is in 2017–18 in South Australia and Victoria.[272]
- From 2018–19 to 2021–22, progressively decreasing levels of potential unserved energy conditions are observed over the next four summers, due to increasing renewable generation.
- The potential for unserved energy and not meeting the current reliability standard is projected to then increase in New South Wales and Victoria after Liddell Power Station closes (announced as 2022).
- Retirement of other coal generation in New South Wales after 2022, if not appropriately replaced by firming capability, could significantly increase the risk of load shedding.
- AEMO's analysis shows that renewable generation can provide some support to maintain reliability even without firming capability. However, if this renewable development was to lead to earlier retirement of existing thermal generation, the risk of unserved energy would increase without additional firming capability.
- In Queensland and Tasmania, no material unserved energy risk is expected in these regions across the 10-year assessment period for the modelled scenarios.

Further, AEMO notes the projected unserved energy risk:[273]

- increases if maximum demands are higher than forecast (for example due to higher usage and/or lower than projected uptake of energy efficiency measures or rooftop PV).
- decreases if the modelling assumes increased investment in renewable generation.

4.3.2 EY's unserved energy forecasts prepared for the Panel's Reliability standard and settings review

In November 2017 EY produced a draft modelling report to accompany the publication of the Panel's *Reliability standard and settings review*. EY was engaged to provide modelling to support the Panel's consideration of the appropriate reliability standard and settings to apply in the NEM from 1 July 2020.

271 AEMO, *ESOO*, p. 1.

272 This risk is being addressed by the South Australian Government's Energy Plan developing additional diesel generation and battery storage, and AEMO pursuing supply and demand response through the RERT provisions.

273 AEMO, *ESOO*, p. 1.

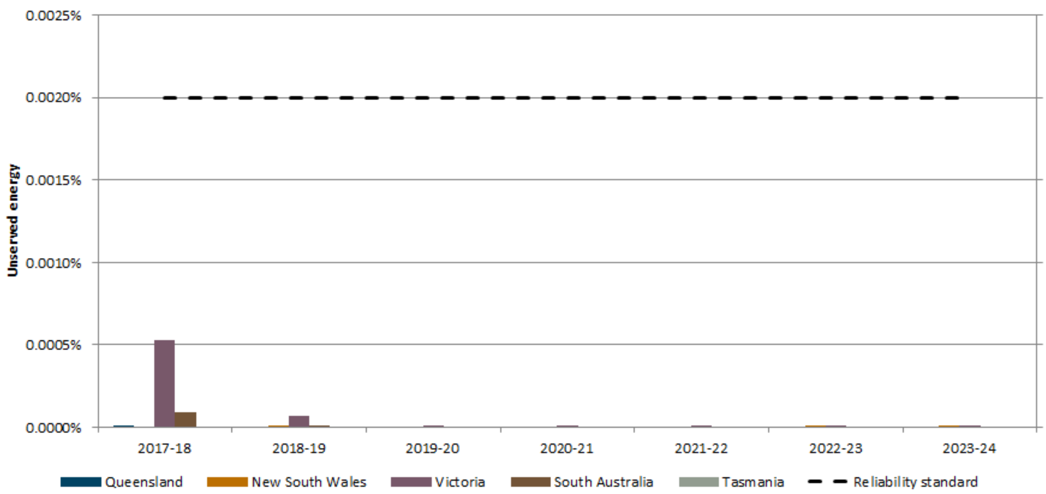
Rationale

The purpose of the EY base scenario is to reflect the most likely outcomes for the national electricity market from 1 July 2020 – 1 July 2024.[274]

Outcomes

The base scenario modelling conducted by EY (and associated sensitivity analysis) has forecast a level of unserved energy that is well below the expected level of unserved energy defined by the reliability standard. The highest unserved energy was forecast for 2017-18 in Victoria at 0.00053 per cent (around one quarter of the standard). Figure 4.8 presents the unserved energy modelling outcomes for the base scenario.

Figure 4.8 EY's unserved energy projections



Source: EY

To further test the sensitivity of the unserved energy outcomes to circumstances such as high demand or higher forced outage rates, EY ran the base scenario varying several key parameters:

- Demand – using AEMO's most recent strong demand forecast rather than neutral demand.
- Generator outage rates – using higher generator forced outage rates (significantly higher than the base assumptions for many generators).

Over the review period the level of unserved energy forecast by the base scenario model under these sensitivities remains well below the reliability standard. The highest forecast level of unserved energy under this sensitivity analysis is in New South Wales,

274 In the *2018 Reliability standard and settings review* the Panel must consider the appropriate reliability standard and settings for the period 1 July 2020 - 1 July 2024. EY also conducted further iterative market modelling under alternative scenarios to estimate the theoretical optimal market price cap. The methodology for these scenarios involves producing plausible futures where the reliability standard is threatened, meaning that the reliability standard would be exceeded if the reliability settings such as the market price cap were not set sufficiently high to incentivise new entrant investment to keep unserved energy below 0.002 per cent. For more information see EYs draft modelling report: http://www.aemc.gov.au/getattachment/44b31105-68eb-487d-8082-e55f49f27671/EY%E2%80%99s-Draft-Report.aspx

where the impact of high demand and EY's forced outage rates is to increase 2023-24 forecast unserved energy to approximately 0.0003 per cent. As compared with the reliability standard of 0.002 per cent, this is a level of unserved energy that, is around one seventh of the standard.

The modelling suggests that unserved energy is most likely to occur during summer months, predominantly in the late afternoon between 3.30pm and 7.30pm.

The Panel notes that the above unserved energy findings are forecasts underpinned by modelling assumptions that aim to reflect the likely outlook for the national electricity market over the review period. As such, actual unserved energy outcomes will differ from forecasts. In addition, as described in section 4.1.3, AEMO has intervention powers under the rules to address potential shortfalls of reserves which will tend to limit actual occurrences of unserved energy.

4.3.3 AEMO's GSOO projections of gas availability

The Panel also reports on projections of gas availability and impacts on electricity markets. These projections are presented in AEMO's September 2017 *Update to Gas statement of opportunities*. AEMO forecasts that there is potential for an annual energy shortfall in the domestic gas market of 54 petajoules (PJ) in 2018 and 48PJ in 2019 in eastern and south-eastern Australia.[275]

AEMO has highlighted the increasing interaction between gas and electricity supply.[276] In the update to the 2017 GSOO, AEMO reported that:[277]

- Continuing flexibility in gas demand for LNG exports will be important for management of unexpected events in the gas supply chain, or new increases in gas demand by gas powered generators to maintain NEM power system security and reliability.
- With an increasing mix of renewable energy to supplement the significant fleet of coal generators in the NEM, and with gas generators typically providing mid-merit electricity generation (which adjusts during the day as demand changes), the demand for gas powered generators is likely to increase.
- In 2017, the declining trend in gas powered generator consumption has reversed, due to:
  - an increasing operational requirement to operate gas powered generation in South Australia to support security of supply
  - the retirement of Hazelwood Power Station reducing the amount of available coal energy in the NEM, resulting in increased operation of gas powered generators

275 AEMO, *Update to GSOO*, September 2017, p. 3. In other words, forecasts suggest that aggregate gas supply available to the domestic market in eastern and south-eastern Australia may not be sufficient to meet the total annual energy requirements of domestic gas users (including gas powered generators) in these regions in 2018 and 2019.

276 AEMO, *GSOO*, March 2017, p. 24.

277 AEMO, *Update to GSOO*, September 2017.

– higher wholesale electricity market prices, which have affected gas powered generators operations because gas is the most price responsive generation fuel.

The Panel notes gas producers and pipeline operators made a commitment to Commonwealth Government to make gas supply available to electricity generators during peak NEM periods.[278]

The Panel also notes that AEMO is currently conducting a review of the market parameters in the Short Term Trading Market and Declared Wholesale Gas Market. The final report for this review is to be published by 30 April 2018.[279]

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 National Energy Guarantee

In October 2017, the Commonwealth Government announced a National Energy Guarantee (the guarantee), proposed by the Energy Security Board, which would require retailers to:[280]

- contract with or invest in generators or demand response to meet a minimum level of dispatchable on demand electricity and
- keep their emissions below an agreed level.

The guarantee aims to support the provision of reliable, secure and affordable electricity with a focus on ensuring: [281]

- the reliability of the system is maintained
- electricity sector emissions reductions needed to meet Australia's international commitments are achieved
- the above objectives are met at the lowest overall costs.

In other words, the guarantee combines reliability outcomes and emissions targets to achieve a single energy price that guides investment and operation in the lowest cost

278 Department of Industry, Innovation and Science, *Heads of Agreement – The Australian East Coast Domestic Gas Supply Commitment*, 3 October 2017.

279 For more information on the review of gas market parameters, see the consultation paper on the review: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Gas_Consultations/2017/Gas-market-parameters/AEMO---Gas-Market-Parameter-Review-2018---Consultation---Final.pdf

280 In August 2017 a new Energy Security Board, chaired by Dr Kerry Schott AO, was established by the COAG Energy Council. The Board's role is to coordinate the implementation of the reform blueprint produced by Australia's Chief Scientist, Dr Alan Finkel AO. The ESB will also provide whole of system oversight for energy security and reliability to drive better outcomes for consumers. The board comprises an Independent Chair, Independent Deputy Chair and the heads of the Australian Energy Market Commission, Australian Energy Regulator and Australian Energy Market Operator.

281 Energy Security Board, *Overview of the National Energy Guarantee*, November 2017, p. 1.

resources. The guarantee is designed to integrate energy and emissions policy – both energy and emissions targets are reflected in a single energy price. That energy price will signal how much electricity the market needs and when it is needed, while also reflecting the cost of meeting Australia's emissions targets.[282]

The following timeframes have been proposed by the Energy Security Board:

- reliability guarantee starts in 2019
- emissions guarantee starts in 2020, replacing the Renewable Energy Target.

In November 2017, the COAG Energy Council agreed to the continued development of the design of the Guarantee.[283]

4.4.2 Reliability frameworks review

On 19 December 2017, the AEMC published an interim report for the self-initiated *Reliability frameworks review*.[284] The AEMC's interim report assessed the following areas of the reliability framework.

- **key concepts of dispatchability and flexibility:** Dispatchability and flexibility are already valued and rewarded in the existing contract, spot, and ancillary services markets, and in a way that reflects their inherent characteristics. For example, more flexible generating units are able to respond quickly to high prices in the market, and so get rewarded by earning higher revenues. However, the AEMC will consider whether the existing signals are "accurate" or "precise" enough to fully reflect these concepts. Conclusions on this question will lead to a better understanding of how a definition of 'dispatchability' could be created.
- **forecasting and information processes:** Forecasts and information provision to the market are the foundation of the reliability framework. As the electricity system evolves, it is likely there could be increased inaccuracies in forecasting. For example, a higher penetration of variable renewable generation, combined with more extreme weather days, will make it harder to forecast output from these resources. Increased inaccuracies may result in increased risks for participants (for example, when to be available or to rebid) and make it more difficult for AEMO to operate the system in tight supply conditions. It will likely be worthwhile to explore whether there are ways these variances can be better managed through the forecasting process or, alternatively, whether there are ways to rely less on forecasts.
- **market-based aspect of reliability, that is, the contract market:** Reliable supply in the NEM is supported by the inherent and symmetrical incentive for buyers and sellers to agree financial contracts outside the NEM spot market to have more certainty over costs and revenue over time. Alternatively, participants can invest in both retail and generation assets (vertical integration) to manage their risks.

282 For more information on the guarantee refer to: http://www.coagenergycouncil.gov.au/publications/energy-security-board-update

283 COAG Energy Council, *Meeting Communique – Friday 24 November 2017*, p. 1.

284 For more information on the *Reliability frameworks review*, see the project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Frameworks-Review

Contract markets also support reliability by informing participant investment and operational decisions. It is not evident the level of trading in the contract market should be cause for concern. However, information on the contract market, important for good investment and operational decisions, is not widely available. The Commission is therefore pleased the Australian Financial Markets Association is restarting its survey of the turnover of over-the-counter contracts.

- the following Finkel Panel recommendations:
  - **Strategic reserve:** Some form of a safety net, such as a limited and targeted ability for a system operator to pay a premium for capacity that is not otherwise being traded in the market, is appropriate in the event that the market is expected to fail to meet the reliability standard.
  - **Wholesale demand response:** Demand response refers to changes in consumption in response to signals to do so. It is hard to determine how much demand response is available in the wholesale market at values below the market price cap, since it is not highly visible. If there is wholesale demand response that is currently being underutilised, then there are opportunities for new and existing parties to capture this value. However, it can be difficult for third parties to capture the value associated with wholesale demand response under the current framework, for example, where each customer can only have one party responsible for its consumption at its meter.
  - **Day-ahead markets:** Despite not having a formalised day-ahead market, the NEM has features that play a similar role, for example, pre-dispatch supported by a liquid financial derivatives market. It is not clear to the AEMC what issues, and their materiality, a day-ahead market would solve in the NEM. Understanding both is crucial for identifying the best solution. AEMC analysis suggests that development of day-ahead markets in the US required the introduction of complementary reforms (such as nodal pricing and firm transmission rights) to achieve the intended outcome of such a market design. Reforms of this nature take a considerable amount of time and resources to implement, and there may be more immediate actions that could be done to assist in the NEM.

A directions paper for this review will be published in March 2018.

4.4.3 Review of the reliability standard and settings 2018

On 21 November 2017, the Panel published the draft report on the *Reliability standard and settings review*.[285] In accordance with the rules, the Panel is required to review the reliability standard and settings every four years. The standard and settings and their respective levels are outlined in Table 4.3.

285 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#

Table 4.3 Reliability standard and settings

Component and purpose	Current and recommended level[286]
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: 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)
Administered price cap: Limits participants' financial exposure to prolonged high prices, being the price 'cap' that applies when the cumulative price threshold is exceeded.	$300/MWh
Market floor price: Prevents market instability, by imposing a negative limit on the total potential volatility of market prices in any half hour trading interval.	-$1,000/MWh

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.
- 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 proposed to leave the reliability standard and reliability settings for the NEM unchanged for the period 1 July 2020 – 1 July 2024. The Panel considers this appropriate as:

286 Both the value of the market price cap and the cumulative price threshold will remain indexed to CPI

- The existing standard and settings are, in its view, still achieving their purpose and are likely to continue to do so out to 2023/24.
- 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, and the absence of sufficient evidence in support of a change to the price settings.
- Matters relevant to other components of the broader market and regulatory frameworks for reliability in the NEM are being considered through other proposals and reviews being progressed by the market bodies.

The Panel is required to publish its final report by 30 April 2017.

4.4.4 Declaration of lack of reserve conditions rule

On 19 December 2017, the AEMC made a final rule that promotes short-term reliability in the NEM by modifying the framework for the declaration of LOR conditions to be more flexible and transparent.

The final rule introduces a more flexible way for AEMO to declare LOR conditions, allowing the system operator to move from the current contingency-based deterministic approach, to one that is probabilistic, while also maintaining the transparency of the existing framework.

The key features of the final rule are:

- the removal of the three levels of contingency-based LOR definitions descriptions from the rules and replacement with a high-level description of lack of reserve condition: "when AEMO determines, in accordance with the reserve level declaration guidelines, that the probability of load shedding (other than the reduction or disconnection of interruptible load) is, or is forecast to be, more than remote."
- the introduction of an obligation for AEMO to develop and publish reserve level declaration guidelines that set out how AEMO will determine a lack of reserve condition
- minimum requirements for the guidelines, including obliging AEMO to declare at least three probability levels that indicate an increasing level of probability
- the introduction of the factors that AEMO must take into account when assessing how to declare an LOR
- a requirement for AEMO to use an amended version of the rules consultation procedures when amending the guidelines
- a requirement for AEMO to report on the operation of the LOR framework every quarter.

The final rule improves the LOR framework since it will better predict the risk of load shedding, which will lead to more efficient outcomes on short-term reserves and promote reliability for consumers.

4.4.5 Coordination of generation and transmission investment review

In February 2016, the COAG Energy Council requested that the AEMC implement a biennial regime to report on a series of drivers that could impact future transmission and generation investment, in accordance with a terms of reference and under section 41 of the National Electricity Law.

The terms of reference set out that the AEMC will undertake a two-stage approach to the reporting of conditions that influence transmission and generation investment:[287]

- **Stage 1:** In the first stage, analysis is to be undertaken on a set of drivers that influence the co-ordination of transmission and generation investment. The aim of the first stage is to determine whether there is a substantial change in a driver(s) such that it suggests that there is an environment of major transmission and generation investment and that this investment is uncertain in its technology and location. If it is determined that such conditions are present, the reporting will progress to the second stage.
- **Stage 2:** The second stage is to be a more in-depth assessment of how the driver(s) have changed, to suggest that investment of an uncertain nature is likely to take place. The second stage will also include assessment of whether the implementation of a model that would introduce more commercial drivers into transmission and generation investment, or other options for changes to the current regulatory framework, would meet the National Electricity Objective.

Stage 1 of this review concluded in July 2017 and the Commission recommended that the review progress to stage 2. Three decision criteria were met in making this recommendation. The decision criteria are:

- **The drivers of transmission and generation investment have significantly changed since July 2015:** There is increased uncertainty regarding government emissions reduction policy, this is having ramifications for investor confidence. There is an observed trend of thermal generation exiting the market and being replaced by renewable generation. The take-up of distributed energy resources is expected to continue, with new business models entering the market seeking to maximise the benefits from these resources.
- **There is expected to be large amounts of transmission and generation investment:** Increased low emission generation will be needed to reduce the emissions intensity of the generation sector. Renewable generation may potentially locate in areas that are a distance from existing transmission infrastructure. It is therefore likely that the shape of the transmission network will need to change in response to reliably supply consumers.
- **The expected future investment is uncertain in its location and technology:** This is because of uncertainty regarding future emissions reduction policy, the

287 For more information on the coordination of generation and transmission investment review, see the project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi#

changing generation mix, changing relative technology costs and the potential for new investments to maintain system security.

On 22 August 2017 the AEMC published an approach paper to commence stage 2. The approach paper provided greater detail on the main issues that have been identified with respect to the coordination of transmission and generation investment and to provide an overview of some of the options to ameliorate these issues.

An options paper will be published in February 2018, which will narrow down the various options under consideration and provide more detail in each chosen option

4.4.6 Health of the national electricity market report

On 20 December 2017, the Energy Security Board published the inaugural *Health of the national electricity market report*.[288] The report tracks the performance of the system, the risks it faces, and the opportunities for improvement. In summary, the Energy Security Board reports that "the National Electricity Market is not in the best of health. The three immediate symptoms are:

- electricity bills are not affordable
- reliability risks in the system are increasing; and
- future carbon emissions policy is uncertain."

The Energy Security Board notes that one important measure to meet these three challenges is the National Energy Guarantee.

4.4.7 Finkel Panel's Independent review into the future security of the national electricity market - blueprint for the future

At an extraordinary meeting on 7 October 2016, COAG energy ministers agreed to an independent review of the national electricity market to take stock of its current security and reliability and to provide advice to governments on a coordinated national reform blueprint.[289] Dr Alan Finkel AO, Australia's Chief Scientist was Chair of the Expert Panel that conducted the review. *The Blueprint for the Future Security of the National Electricity Market* delivers a plan to maintain security and reliability in the National Electricity Market in light of the significant transition underway, including due to rapid technological change. The final report for the review was published on 9 June 2017.

The blueprint sets out a vision for the future, with four key outcomes:

- increased security:
  - Obligations on new generators to provide essential security services

288 For more information on the Health of the National Electricity Market Report, see: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/The%20Health%20of%20the%20National%20Electricity%20Market_19122017.pdf

289 For more information on the independent review into the future security of the national electricity market, see: https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-blueprint-for-the-future-2017.pdf

- More conservative operation in each region through maintaining system inertia and tighter frequency control
- A stronger risk management framework to protect against natural disasters and cyber security attacks.

- future reliability:
  - Obligations on new generators will ensure adequate dispatchable capacity in all regions
  - New generators incentivised to enter the market
  - Existing low-cost generators do not close prematurely
- rewarding consumers:
  - Large and small consumers rewarded for reducing their demand when needed
  - System upgrades and new generation will be achieved at lowest cost
  - Better access to information to support consumer choice
- lower emissions:
  - A continuous emissions reduction trajectory delivering certainty
  - Emissions reduced by 28 per cent below 2005 levels by 2030, heading towards zero emissions in the second half of the century

The vision will be enabled by three key pillars:

- an orderly transition - to provide certainty through an agreed emissions reduction trajectory:
  - Clean Energy Target adopted to drive investment and reduce emissions
  - All generators will be required to provide three years' notice of closure
- system planning - to help make the transition to an innovative, low emissions electricity system:
  - A system-wide grid plan informs network investment decisions
  - Regional security and reliability assessments
- stronger governance - to drive faster rule changes, overcome challenges and deliver better outcomes:
  - A new Energy Security Board to deliver the blueprint and provide system-wide oversight
  - Strengthened energy market bodies

On 14 July 2017, the COAG Energy Council agreed to implement 49 of the review's 50 recommendations.[290] The Clean Energy Target was not adopted by the Commonwealth Government.

4.4.8 Final report from the New South Wales Energy Security Taskforce

On Tuesday 21 February 2017, New South Wales Energy and Utilities Minister announced the establishment of a New South Wales Energy Security Taskforce. The Taskforce released its final report on 19 December 2017. The report examined issues that need to be addressed to strengthen the longer-term resilience of the New South Wales electricity system.[291] It considers the challenges of achieving a stable and reliable power system, which is characterised by low electricity costs and low emissions, while managing the transition to new forms of generation technologies in a changing environment. The Taskforce examined a series of issues including:

- emerging risks to the electricity system, including from extreme weather
- market or regulatory barriers to new capacity entering the market and the opportunities associated with technology and new business models that could improve security and reliability in New South Wales
- risks to New South Wales and the Sydney CBD in particular of a black system event and how the Government might reduce these risks and ensure New South Wales is well prepared in the unlikely event of a state-wide blackout

4.4.9 AEMO/ARENA demand response trial

On 19 May 2017 AEMO and ARENA announced a joint demand response trial.[292] The three-year initiative, which commenced in summer 2017/18, is to pilot demand response projects, and encourage other market responses to provide firm capacity. The trial’s dual aim is to:

- Provide reserves for the 2017/18 summer as part of RERT.
- Trial a strategic reserve model (referencing international market designs) for reliability or emergency demand response to inform future market design.

Under the trial, ARENA is providing, over a period of three years, up to $28.6 million of funding for projects, with the New South Wales Government providing $7 million, for energy users to become demand response enabled. Funding will cover metering, monitoring, storage, distributed generation equipment, and other set up costs. Successful applicants sit on the short notice RERT panel, which enables AEMO to use these resources in periods of tight demand/supply situations.

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290 See: http://www.coagenergycouncil.gov.au/publications/12th-energy-council-meeting-communique-includes-11th-meeting-communique

291 For more information on the New South Wales Energy Security Taskforce, see: http://www.chiefscientist.nsw.gov.au/reports/nsw-energy-security-taskforce

292 For more information on the demand response trial, see: https://www.aemo.com.au/Media-Centre/AEMO-and-ARENA-demand-response-trial-to-provide-200MW-of-emergency-reserves-for-extreme-peaks

In October 2017, ARENA and AEMO announced 10 pilot projects involving eight recipients had been successful in the competitive round. Participation ranges across network providers, retailers, aggregators, direct energy users, and technology providers such as smart thermostat developers. The pilot projects will involve:

- Energy users volunteering to be available to conserve their energy use for short periods during a peak demand event, in exchange for incentives.
- Both commercial and industrial energy users and residential household consumers.

These reserves will be available for dispatch within 10 minutes or within one hour. During a peak demand event, when reserves reach critically low levels, AEMO will be able to call on these pilot projects to dispatch their reserves, and will pay usage charges under the RERT agreements. The pilot projects will trial a range of different demand response models, technologies, and incentives.

Through the initiative 143MW of demand response, from Victoria, South Australia, and New South Wales, was delivered in summer 2017/18. The initiative will deliver 189MW of demand response in year two, and 200MW in year three, across the same three regions.

4.5 Relevant government interventions

The Panel notes there have been a number of recent government interventions relevant to the reliability of the system. These are summarised below.

4.5.1 Snowy 2.0

On 16 March 2017, Snowy Hydro announced its proposal to carry out a feasibility study into the expansion of the pumped hydro-electric storage in the Snowy Mountains Scheme, also known as the Snowy 2.0 project.[293] Snowy 2.0 will increase generation capacity by up to 2000MW, and at full capacity, will provide approximately 350,000MWh of energy storage. On 20 December 2017, Snowy Hydro published a feasibility study that confirmed the "Snowy 2.0 pumped hydro expansion project is both technically and financially feasible". Following consideration, Snowy Hydro’s independent Board of Directors has approved to progress the Snowy 2.0 project from feasibility stage towards final investment decision and to undertake further work and project refinements.

The project cost is estimated at $3.8 - $4.5 billion, not including the cost of required upgrades to transmission infrastructure. The first power to be generated from Snowy2.0 is expected in 2024.

4.5.2 Tasmania's Battery of the nation

The Tasmanian Government's *Battery of the Nation* initiative set up a blueprint for how Tasmania's renewable resources are developed over coming decades. The initiative

293 For more information on the Snowy2.0 feasibility study, see: http://www.snowyhydro.com.au/our-scheme/snowy20/snowy-2-0-feasibility-study/

began in April 2017 and involves developing a pathway of future development opportunities for Tasmania to make a greater contribution to the NEM.

The initiative consists of projects including:

- ARENA will work with Hydro Tasmania to explore new pumped hydro schemes that could deliver up to 2500MW of pumped storage generation capacity – nearly doubling Hydro Tasmania's current capacity.
- ARENA will consider a study which includes replacing one of Hydro Tasmania's oldest power stations at Tarraleah with a modern design, boosting production by up to 200GWh each year, and extending its operating life by 80 years. The Gordon Power Station would also have an extra turbine installed to boost efficiency.

4.5.3 South Australian Government energy plan

On 14 March 2017, the South Australian government announced an 'energy plan' which intends to address energy reliability and security in South Australia.

The energy plan consists of measures including:[294]

- **Battery storage and renewable technology fund:** The world's largest lithium ion battery (100MW, 129MWh) officially launched in South Australia on 1 December 2017. It is part of a new $150 million Renewable Technology Fund.
- **New generation, more competition:** The State Government will use its bulk-buying power to attract new electricity generation to increase competition and put downward pressure on prices.
- **State-owned gas power plant:** The South Australian Government will build its own gas power plant (250MW) to have government-owned stand-by power available in South Australia for emergencies.
- **South Australian gas incentives:** The State Government will offer incentives to source more gas for use in South Australia, replacing coal-fired energy from Victoria.
- **Local powers over national market:** Introducing the ability for the South Australian Minister for Energy to direct participants in South Australia, including AEMO and interconnectors with Victoria.
- **Energy security target:** A new target will increase South Australia's energy self-reliance by requiring more locally generated, cleaner, secure energy to be used in South Australia.

294 For more information, see: http://ourenergyplan.sa.gov.au/our-plan.html

5 Security review

This chapter describes:

- the Panel's consideration of the system security performance of the NEM in 2016/17
- major security incidents in the NEM in 2016/17
- projections of system security and emerging issues
- work underway addressing system security issues in the NEM.

The Panel notes following key system security trends and outcomes:

- **Meeting frequency requirements:** In 2016/17 the amount of time spent outside the normal operating frequency band increased for the mainland and decreased for Tasmania. In 2016/17 the frequency operating standard was met in the mainland. However it was not met in Tasmania for seven months of 2016/17.[295] As a general trend the number of normal operating frequency band exceedances has increased over the past three years for both the mainland and Tasmania.
- **Under frequency load shedding:** In 2016/17 there were three instances where under frequency load shedding schemes were triggered; 1 December 2016 in South Australia, 20 December 2016 in Tasmania and 12 March 2017 in Tasmania.
- **Instances power system was not in a secure operating state:** In 2016/17 there were 11 instances where the power system was not in a secure state for greater than 30 minutes.[296] Over the past three years there has been an increase in the number of times secure operating limits were exceeded for greater than 30 minutes.
- **Voltage limits:** In 2016/17, four out of the 11 instances where the system was not in a secure operating state for greater than 30 minutes were due to secure voltage limits being exceeded.[297]
- **System restart ancillary services:** In 2016/17 system restart ancillary services were called upon, following the 28 September 2016 black system event in South Australia.[298]
- **Power system directions:** In 2016/17 AEMO issued eight power system directions to maintain the system in a secure operating state.

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295 AEMO investigated the gradual decline in frequency performance and identified that times of prolonged frequency deviations coincided with a large portion of regulation FCAS enabled in Tasmania. During these times, the automatic generation control (AGC) system at AEMO was not able to dispatch the full enablement of regulation FCAS in Tasmania due to its detuned configuration at the time.

296 Load was lost on four of these instances.

297 On all four occasions, outages of transmission elements were a contributing factor to secure voltage limits being exceeded.

298 This was the first time system restart ancillary services have been called upon since the start of the NEM.

System security issues came to the fore in 2016/17. In particular, the black system event in South Australia was the first time a state-wide blackout had occurred in Australia since 1964. Tornadoes damaged transmission infrastructure causing faults on the network that led to a reduction in wind farm output and the trip of the Heywood interconnector. This led to a supply imbalance with local generation in South Australia much less than the load. The low level of inertia in South Australia meant that a high rate of change of frequency was experienced with remaining generators tripping off and disconnecting from the system, culminating in the loss of all supply. The system restoration process was complicated by the failure of the two contracted system restart units. In the wake of the incident AEMO made a number of recommendations that have since been actioned.

The other major issue in 2016/17 was the continued degradation of frequency performance in both the mainland and Tasmania. A greater number of frequency excursions were observed and the frequency operating standard was breached in Tasmania for seven months of the 2016/17 year. This was driven in part by a gradual shift toward more variable sources of electricity generation and consumption, as the retirement of conventional generators has led to a reduction in inherent levels of inertia in the power system and lessened the system's ability to resist frequency disturbances. Reductions in levels of primary frequency control are contributing to this degradation in frequency performance.

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 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.[299]

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.[300]

This section examines whether key power system quantities, such as frequency and voltage, were maintained at the levels required in system performance standards during 2016/17. The section also examines performance stability of the power system in 2016/17. These system security performance indicators are explained in greater detail in appendix G.

299 For more information on these principles refer to rules clause 4.2.6.

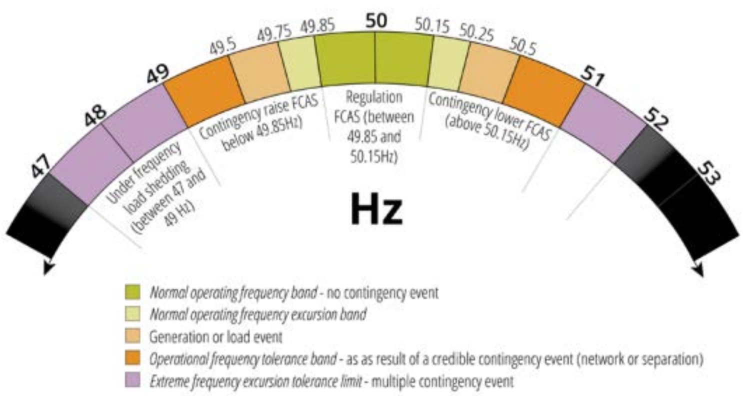
300 The NEM is considered to be in a secure operating state if the power system is a satisfactory operating state and will return to a satisfactory operating state following a credible contingency in accordance with the power system security standards. The power system security standards are the standards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

5.1.1 Frequency

The control of power system frequency is a crucial element of managing power system security. The frequency of the power system reflects the balance between power system demand and generation. For instance, if a generator were to suddenly trip and not be available then the frequency would fall as there would be insufficient generation to meet demand.

The power system frequency is generally maintained by AEMO within a range called the normal operating frequency band (NOFB). This is defined in the frequency operating standards, which are determined by the Panel.[301] When the system is operating normally (i.e. with no regions separated or being restored from a contingency event) the NOFB is the range of frequency from 49.85Hz to 50.15Hz, this is shown in Figure 5.1 and Figure 5.2.[302] The frequency operating standard requires the frequency to be within the NOFB for 99 per cent of the time under normal operating conditions.[303]

Figure 5.1 Frequency bands - mainland NEM



Source: AEMC, *Frequency control frameworks review, issues paper*, November 2017, p. 16.

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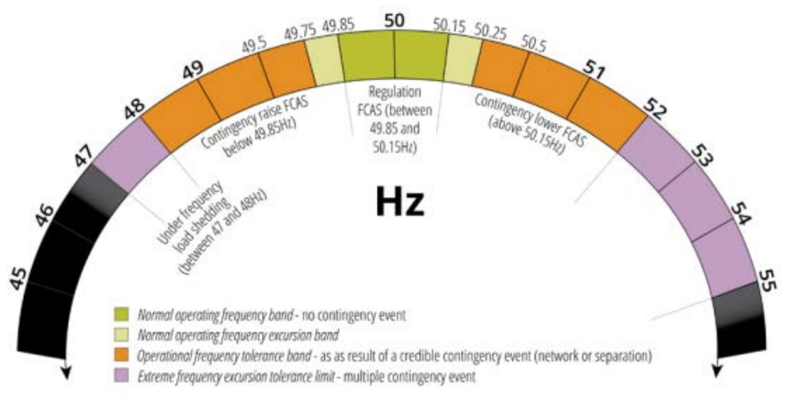
301 The frequency operating standards for the mainland and for Tasmania are available on the AEMC's website, http://www.aemc.gov.au/Australia-s-Energy-Market/Market-Legislation/Electricity-Guidelinesand-Standards. The Panel is currently in the second stage of its review of the frequency operating standard.

302 It is important to keep the power system frequency as close to 50Hz as possible, as generation units and some load equipment are designed to work most efficiently when frequency stays within this band. In addition, significant variations from the normal operating frequency band can cause generating units to "trip" and lose synchronism with the system.

303 Reliability Panel, *Application of Frequency Operating Standards During Periods of Supply Scarcity*, April 2009.

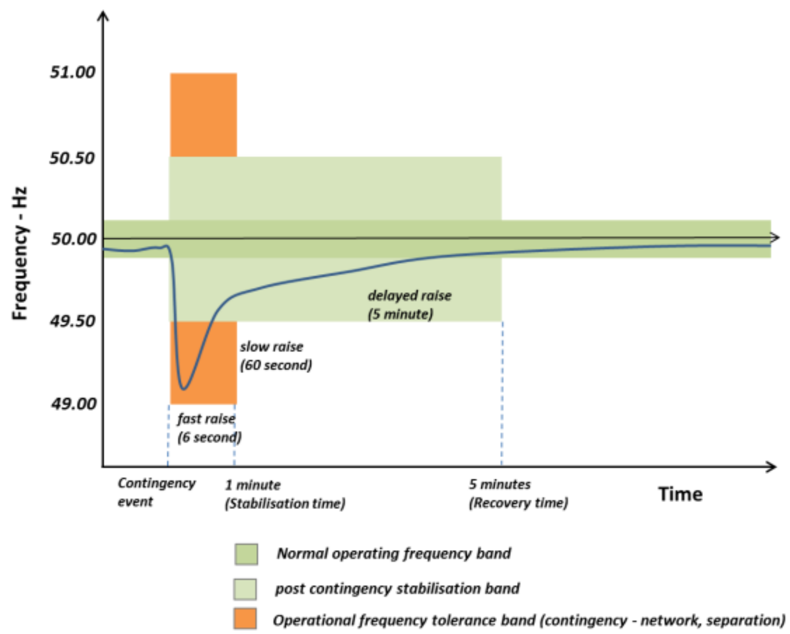
Figure 5.2 Frequency bands - Tasmania



Source: AEMC, *Frequency control frameworks review, issues paper*, November 2017, p. 16.

If the frequency leaves the NOFB, AEMO will use FCAS to attempt to return the frequency to the NOFB as per the frequency operating standards. This is shown in Figure 5.3.

Figure 5.3 Frequency deviation and FCAS response



Source: AEMC, *Frequency control frameworks review, issues paper*, November 2017, p. 19.

The mainland and Tasmania have different frequency operating standards. The Tasmanian power system is different from the mainland in that it:

- is small in terms of the size of the load and installed generating capacity
- has relatively large load, generator and network contingencies, as a proportion of the total system
- is predominantly supplied by hydro generating units
- can have a relatively low inertia, particularly when Tasmania is importing energy via Basslink at a time of low Tasmanian demand

- experiences shortages of fast acting FCAS because of the slow response of hydro generators to frequency disturbances.[304]

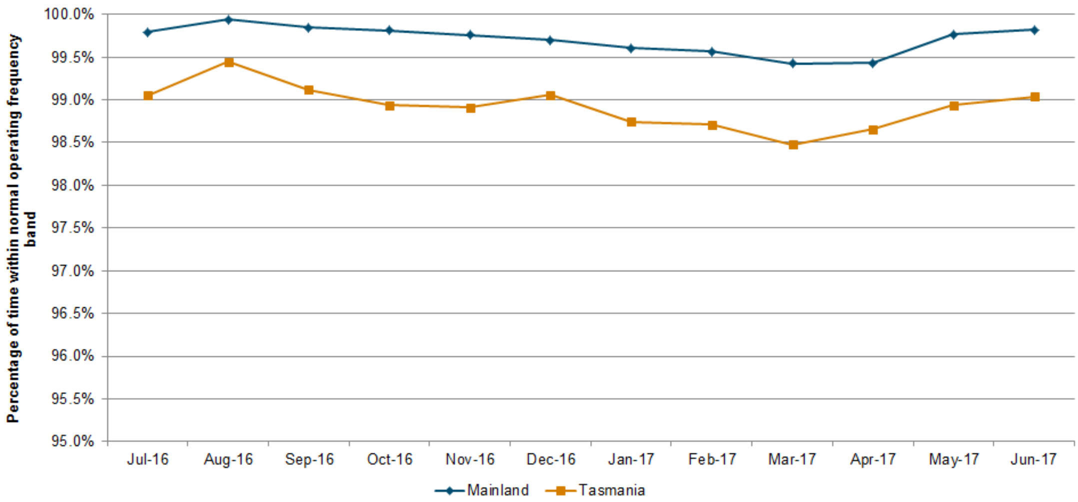
For these reasons, the Panel has developed different frequency operating standards for Tasmania to the mainland. If Tasmania was required to have the same frequency operating standards as the mainland, it would likely result in a shortage of FCAS resources, or substantially higher FCAS costs.

Figure 5.4 shows that in 2016/17, the mainland frequency remained within the NOFB more than 99.4 per cent of the time. This indicates that the mainland power system was operating in a condition where load was balanced with generation and frequency was kept within the bands required under the frequency operating standards.

Tasmania was within the NOFB for more than 98.4 per cent of the time.

More detail on the frequency operating standard is provided in appendix G.

Figure 5.4 Percentage of time within NOFB



Source: AEMO

Mainland

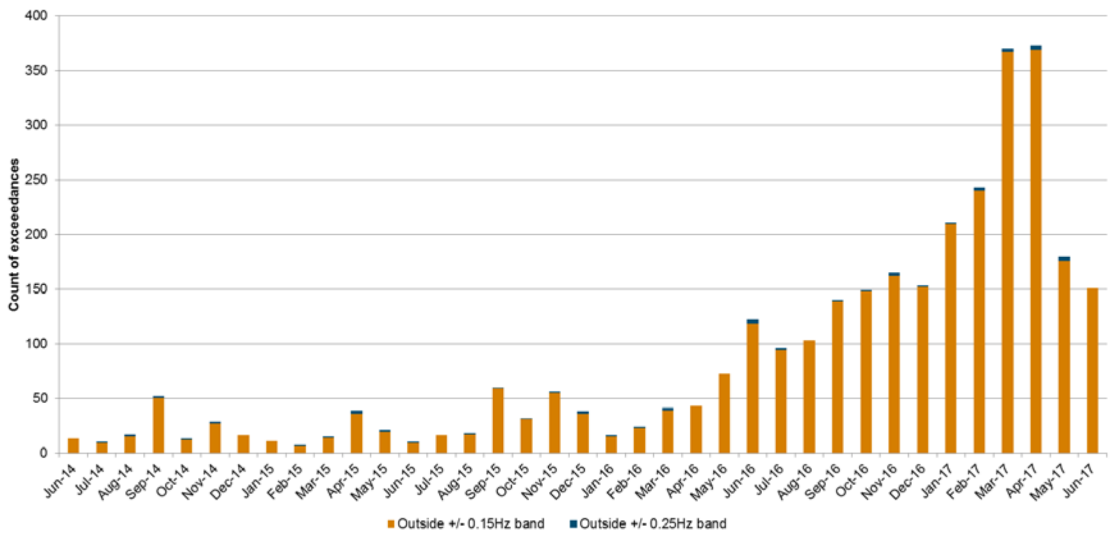
In 2016/17, the system operated outside the NOFB for 93,032 seconds as compared with 25,592 seconds in 2015/16 and 6,640 seconds in 2014/15. Despite an increased amount of time operating outside the NOFB, the percentage of time the mainland frequency was within the NOFB met the required standard of 99 per cent over any 30 day period in 2016-17.[305]

Figure 5.5 shows that over the past three years, the number of times the NOFB has been exceeded on the mainland has increased. This may indicate that the frequency on the mainland has become increasingly variable, and potentially more difficult to contain to within the NOFB.

304 Reliability Panel, *Tasmanian Frequency Operating Standard Review*, December 2008.

305 Reliability Panel, *Application of Frequency Operating Standards During Periods of Supply Scarcity*, April 2009, p.16.

Figure 5.5 Number of frequency band exceedances - mainland



Source: Data for this chart was taken from AEMO, *Frequency monitoring - three year historical*, August 2017, p. 7.

Tasmania

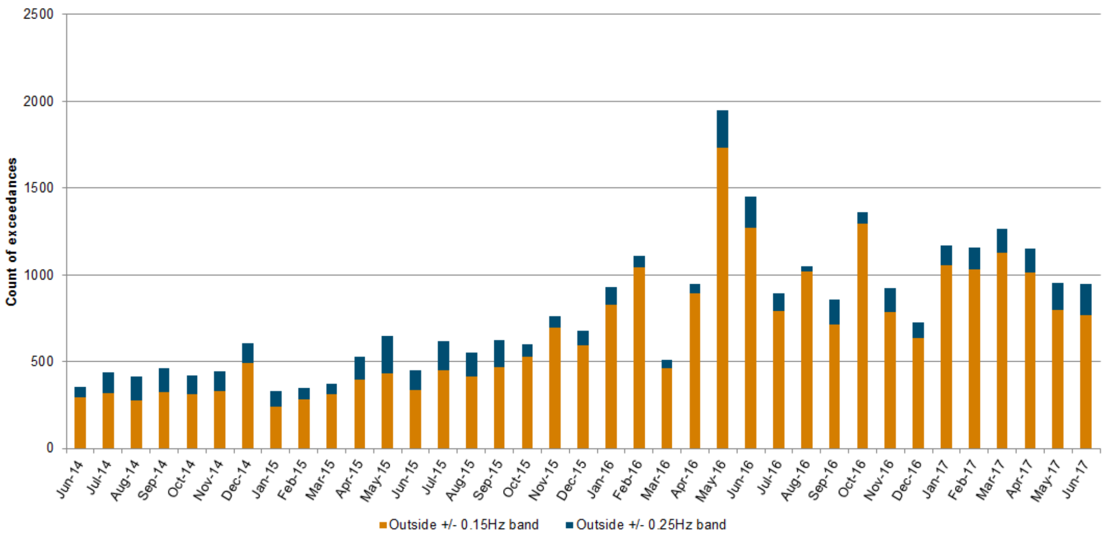
In 2016/17, Tasmania operated outside the NOFB for 338,992 seconds as compared with 398,544 seconds in 2015/16 and 165,040 seconds in 2014/15. In addition, the percentage of time inside NOFB did not meet the required standard of 99 per cent over a 30 day period for seven months of the 2016/17 year.[306] AEMO investigated the gradual decline in frequency performance and identified that times of prolonged frequency deviations coincided with a large portion of regulation FCAS enabled in Tasmania.[307]

Figure 5.6 shows that over the past three years, the number of times the NOFB has been exceeded in Tasmania has increased. The Panel notes that the number of frequency band exceedances in Tasmania is much greater than on the mainland. Additionally, in Tasmania the frequency exceeds the +/-0.25Hz band significantly more often than in the mainland.

306 These months were October 2016, November 2016, January 2017, February 2017, March 2017, April 2017 and May 2017

307 During these times, the automatic generation control (AGC) system at AEMO was not able to dispatch the full enablement of regulation FCAS in Tasmania due to its detuned configuration at the time. On 1 May 2017, AEMO constrained the regulation FCAS from Tasmania to the mainland to 34 MW to ensure that the NEM dispatch engine (NEMDE) only enabled regulation FCAS in Tasmania to the extent that the AGC system could dispatch it under the existing configuration. On 5 May 2017, the AGC gains were increased such that up to 50 MW of regulation enabled in Tasmania by NEMDE could be successfully dispatched by the AGC. These changes have contributed an improvement during May and June 2017. However, more data over a longer period will be required to properly assess the impact. AEMO is further investigating possible changes to the AGC and will review the current configuration when more data is available. AEMO, *Frequency monitoring - three year historical*, August 2017, p. 4.

Figure 5.6 Number of frequency band exceedances - Tasmania



Source: Data for this chart was taken from AEMO, *Frequency monitoring - three year historical*, August 2017, p. 8.

Frequency degradation is being addressed by the Ancillary Services Technical Advisory Group and the AEMC's *Frequency control frameworks review*.[308] For more detail refer to section 5.4.

5.1.2 Under frequency load shedding

If a frequency deviation results in the frequency moving significantly outside of the normal ranges, automatic protection systems operate to trip load (for an under-frequency excursion) or generation (for an over-frequency excursion) to bring the frequency back to within the normal operating standards.[309]

Currently, these protection systems include under frequency load shedding schemes.[310] Under frequency load shedding schemes are designed to arrest the fall in frequency that can occur following a non-credible contingency, such as the simultaneous trip of several generators or transmission lines. Under frequency load shedding schemes do this by disconnecting blocks of consumer load in a controlled manner, until the fall in frequency stops or there is no more load to be shed.[311] In 2016/17, there were three occasions where under frequency load shedding schemes were triggered. These events are detailed in Table 5.1. None of these events met the rules definition of unserved energy.

308 The Ancillary Services Technical Advisory Group is a select group of industry experts that are called upon to provide contributions to AEMO on matters relating to ancillary services (both the currently defined services and any new services potentially needed in the future).

309 Typically, automatic under frequency load shedding mechanisms are triggered when the frequency moves outside of the operational frequency tolerance band of 49Hz to 51Hz.

310 AEMO, *Fact sheet: frequency control*, p. 3.

311 The Panel notes that the AEMC has made a final rule regarding the emergency frequency control scheme rule change. The final rule introduced an over frequency generator shedding scheme, to address sudden increases in power system frequency. More information is provided in section 5.4.3.

Table 5.1 Under frequency load shedding scheme events in the NEM for 2016/17

Date	Region	Incident	Amount of load turned off	Time load turned off	Time load turned on[312]	Energy interrupted
1 December 2016	South Australia	Trip of the Moorabool –Tarrone 500kV transmission line	190MW[313]	12.16am	1.45am	282MWh
20 December 2016	Tasmania	Outage of both Sheffield to George Town (SH–GT) 220kV transmission lines	170MW	9.39am	10.45am	187MWh
12 March 2017	Tasmania	Trip of the Basslink interconnector	144MW[314]	9.42pm	10.30pm	116MWh

The current under frequency load shedding schemes are being reviewed to reflect changing market conditions. The AEMC's final rule relating to emergency frequency control schemes and protected events rule change has made changes to the frameworks to manage extreme over and under frequency events.[315] This is discussed in greater detail in section 5.4.3.

5.1.3 Instances when the system was not in a secure operating state

The power system is in a satisfactory operating state when:[316]

- 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:[317]

312 This is the time when all the load was restored.

313 An additional 40MW was shed that was not associated with operation of the under frequency load shedding scheme

314 The frequency control special protection scheme operated to shed a further 241MW

315 For more information see http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

316 Refer to rules clause 4.2.2 for the full definition of a satisfactory operating state.

317 Rules clause 4.2.4.

- it is in a satisfactory operating state; and
- it 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. During 2016/17, there were 11 instances of the power system being operated outside its secure limits for greater than 30 minutes. These include:

- **28 September 2016, South Australia:** The system was in a secure operating state immediately prior to the initiation of the final sequence of events that led to the black system (at 4.16pm) and loss of all supply to the region. In the final seconds before islanding the system was not in a secure nor satisfactory operating state.[318] For the period after the event, it is very difficult to pinpoint the periods during which the South Australian system was secure, with extensive power system studies required.[319] Throughout the restoration it was AEMO's objective to achieve and remain in a satisfactory operating state where possible, and a secure operating state as early as practical. AEMO concludes that the restored part of the system would have been, and remained, in a secure operating state at the latest from around midnight when sizeable generation had been restored. This means the system would not have been in a secure operating state for roughly seven to eight hours. The black system event is discussed in detail in section 5.2.1.
- **13 November 2016, South Australia:** From 12.10pm to 5.21pm on 13 November 2016, the South Australian power system was operated with only one synchronous generating unit in service.[320] Subsequent analysis has shown that the power system was not in a secure operating state during this period.[321] AEMO has since implemented new procedures to ensure the minimum number of synchronous generating units are on line.[322]
- **28 November 2016, New South Wales:** The power system in NSW was not in a secure operating state for 63 minutes due to high post–contingent voltage levels at Darlington Point substation.[323] The delay in restoring the power system to a

318 The black system was the result of a non-credible disconnection of generation in South Australia.

319 The Panel notes that the rules construct of a 'secure operating state' has no real relevance in the early stages of a complete power system restoration. Security can only be measured when there is sufficient power system equipment operating for a credible contingency event to occur and have the potential to render the remaining operating elements of the power system unsatisfactory.

320 AEMO, *Power system not in a secure operating state in South Australia on 13 November 2016,* 6 April 2017

321 The system strength (fault level) in South Australia would be at such a low level that: variations in voltage could become excessive, especially during switching on of transmission equipment or reactive devices or during normal system changes due to market operation. Studies conducted by AEMO have shown that a minimum of two TIPS B generating units (or equivalent) are required on line for the South Australian power system to be in a secure operating state.

322 No customer load or generation was lost as a result of this incident.

323 AEMO, *Power system not in a secure operating state in New South Wales on 28 November 2016,* 13 July 2017

secure operating state was related to the time required to return a transmission line to work earlier than planned.[324]

- **29 November 2016, Victoria:** The power system in Victoria was not in a secure operating state for 4 hours and 45 minutes due to a number of planned transmission system outages.[325] Problems associated with the dynamic stability analysis application resulted in delays in returning the power system to a secure operating state. The potential for non-secure operation was not identified during the outage planning process. AEMO has updated its power system security assessment tools and processes as a result of this incident.[326]
- **30 November and 1 December 2016, Victoria and South Australia:** During these incidents, the power system in Victoria and South Australia was not in a secure operating state for up to 50 minutes and up to 45 minutes respectively due to the combination of planned outages and the operation of Mortlake Power Station.[327] These reviewable operating incidents are distinct from the separation event that occurred at 1.16am on 1 December 2017.
- **1 December 2016, South Australia:** A fault on the Moorabool to Tarrone 500kV transmission line in Victoria resulted in the loss of the Heywood interconnection between South Australia and Victoria.[328] The power system was not in a secure operating state after this incident for a period of four hours and 20 minutes.[329] This incident resulted in:
  - the disconnection of the Portland aluminium smelter (473MW of load lost) with supply made available after three hours and 14 minutes .
  - the operation of the under frequency load shedding scheme in South Australia (190MW of load lost) with AEMO instructing load to be restored after 38 minutes.[330]

  This separation event is discussed in detail in section 5.2.2.
- **8 February 2017, South Australia:** Demand and supply from renewable and thermal generation were changing rapidly in the period just prior to a loss of system security. The power system was not in a secure operating state for 55 minutes.[331] This incident involved an AEMO direction to ElectraNet to shed

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324 No customer load or generation was lost as a result of this incident.

325 AEMO, *Power system not in a secure operating state in Victoria on 29 November 2016,* 13 July 2017

326 No customer load or generation was lost as a result of this incident.

327 AEMO, *Power system not in a secure operating state in South Australia and Victoria on 30 November and 1 December 2016*, 14 June 2017. No customer load or generation was lost as a result of this incident.

328 AEMO, *South Australian separation event, 1 December 2016*, 28 February 2017

329 The system was not in a secure operating state as AEMO was not able to source sufficient R6 FCAS to completely cover the potential loss of the generation at Pelican Point Power Station. The output of Pelican Point Power Station could not be further reduced.

330 There was also an additional reduction of 40MW that was not associated with the operation of the under frequency load shedding scheme.

331 AEMO, *System Event Report South Australia, 8 February 2017*, 15 February 2017.

100MW of load, with clearance given to restore that load 27 minutes later.[332] This event is discussed in section 4.2.1.

- **10 February 2017, New South Wales:** Extreme temperatures led to high demand conditions in New South Wales. This high demand coincided with forced outages of thermal power stations.[333] The power system was not in a secure operating state for 36 minutes. This incident involved an AEMO direction to Transgrid to shed a potline (290MW of load lost) at Tomago aluminium smelter for 63 minutes. This event is discussed in section 5.2.3.
- **11 February 2017, New South Wales:** This incident involved the trip of multiple transmission lines, caused by faulty protection operation coincident with high voltage faults due to a storm with lightning and high winds.[334] The power system was not in a secure operating state between 9.23pm and 10.41pm (78 minutes).[335]
- **3 March 2017, South Australia:** At 3.03pm on 3 March 2017, a series of faults at ElectraNet's Torrens Island 275kV switchyard resulted in the loss of approximately 610MW of generation in South Australia.[336] There was a 400MW drop in demand however AEMO did not instruct load shedding and there was no operation of the under frequency load shedding scheme. The power system in South Australia was not in a secure operating state for 40 minutes. This event is discussed in section 5.2.4.
- **30 March 2017, Queensland and New South Wales:** An incident occurred where the Lismore static VAR compensator was taken out of service when the Lismore substation flooded.[337] As a result of the static VAR compensator outage, the power system in northern New South Wales and southern Queensland was not in a secure operating state for 66 minutes. The flooding at Lismore substation resulted from heavy rain associated with ex–cyclone Debbie.[338]

Figure 5.7 shows that the number of times the operating system was not in a secure operating state for greater than 30 minutes has increased over the past three years. Secure operating limits were exceeded for greater than 30 minutes four times in 2014/15 and seven times in 2015/16.

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332 Actual load shedding was 300MW due to an issue with SA Power Networks' load shedding software.

333 AEMO, *System Event Report New South Wales, 10 February 2017,* 22 February 2017.

334 AEMO, *Trip of multiple transmission elements in the southern New South Wales area, 11 February 2017,* 15 September 2017.

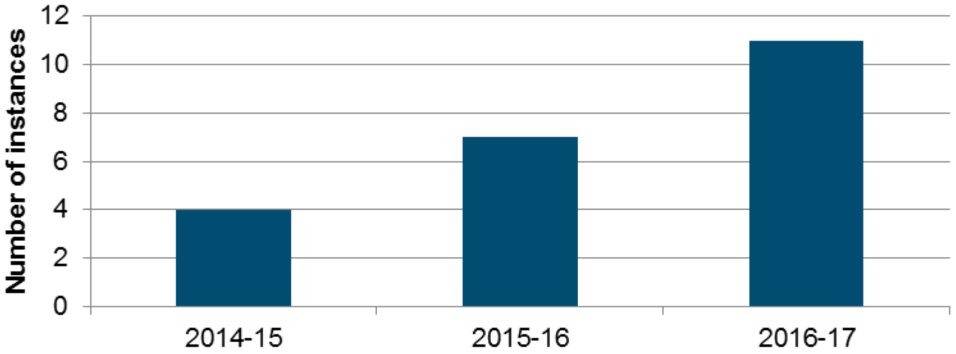
335 No customer load or generation was lost as a result of this incident.

336 AEMO, *Fault at Torrens Island Switchyard and loss of multiple generating units, 3 March 2017,* 10 March 2017.

337 AEMO, *Outage of Lismore SVC on 30 March 2017,* 18 May 2017.

338 No customer load or generation was lost as a result of this incident.

Figure 5.7 **Number of times the operating system was not in a secure operating state for greater than 30 minutes**



Source: AEMO, Incident reports

Maintaining the system in a secure operating state places tighter restrictions on operation than when it is in a satisfactory state. When 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 consumer load shedding. Security management is further discussed in appendix F.

5.1.4 Voltage limits

Satisfactory voltage limits represent the minimum or maximum safe operating level of a network asset set by the asset owner 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.

On four occasions in 2016/17, the power system was not in a secure operating state for greater than 30 minutes due to voltage issues. These four occasions include:[339]

- **28 November 2016, New South Wales**
- **29 November 2016, Victoria**
- **11 February 2017, New South Wales**
- **30 March 2017, Queensland and New South Wales.**

These four events are described above in section 5.1.3.

In 2015/16, there was only one instance of the power system being operated outside its secure limits for greater than 30 minutes in relation to voltage issues.

5.1.5 Constraints

AEMO uses constraint equations to model power system congestion in the NEMDE. Constraint equations can have an impact on pricing and dispatch in the electricity market.

339 On all four occasions, outages of transmission elements were a contributing factor to secure voltage limits being exceeded.

The key findings of the NEM constraint report 2016 were:[340]

- 2016 had the second largest number of constraint equation changes since the start of the NEM. This was mostly due to the constraint equation changes associated with the upgrade of the Heywood Interconnector between Victoria and South Australia.
- The number of constraint binding hours in 2016 was the largest recorded in the past six years. The increase can be attributed to the feeder bushing limit at Boyne Island, new constraint equations in South Australia following the black system event, and Tasmanian FCAS constraint equations following the Basslink outage.

More information on constraints is provided in appendix G. The recently introduced constraint to manage system strength in South Australia is discussed in section 5.3.4.

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, including the timeframe 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 (SRAS) from contracted SRAS providers.

On 2 July 2015 AEMO completed its tender process to acquire SRAS from 1 July 2015 to 30 June 2018 and reported that it had acquired SRAS to a level sufficient to meet the system restart standard for all electrical subnetworks.[341]

Prior to September 2016, AEMO had not called on procured SRAS.[342] However, on 28 September 2016, AEMO drew on SRAS to restore supply in South Australia following the black system event. The system restart plan for this event included restart capability from one of two contracted South Australian SRAS generators (Quaratntine Power Station and Mintaro), and supply from Victoria via the Heywood Interconnector.[343] AEMO's key conclusions related to system restoration from the black system event are:[344]

- The time to restore the majority of the load was in line with restoration times experienced in other recent power system restorations in Australia and elsewhere around the world.
- The failure of the Quarantine Power Station SRAS was due to the switching sequence used.[345] Measures have been put in place and tested to remedy this.

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340 AEMO, *The NEM constraint report*, June 2017

341 AEMO, *System restart ancillary services 2015 tender process report*, 2 July 2015, p. 3, 6.

342 Since the start of the NEM.

343 Wind farms cannot be used in the initial stages of a power system restoration for technical reasons including the variable nature of their output.

344 AEMO, *Black System South Australia 28 September 2016, final report*, March 2017, p. 7.

345 Provision of SRAS from Quarantine Power Station is a staged process: (i) one of the smaller generating units is used to start the larger Quarantine unit; (ii) the larger generating unit is then used to energise the auxiliary supplies of other power stations in the South Australian power

- The Mintaro emergency diesel generator tripped soon after starting, but this did not delay the restoration process because the generator cannot by itself restore large generating units in the Torrens Island area. The cause has been addressed.

A detailed description of the black system event is provided in section 5.2.1.

On 15 December 2016 the Panel completed its *Review of the system restart standard* and published a new system restart standard to apply from July 2018. More information on the new system restart standard is available in section 5.4.2.

5.1.7 Power system directions

Under clause 4.8.9 of the rules, AEMO has the power to issue directions to a market participant to re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state. AEMO may also contract for the provision of reserves through the reliability and emergency reserve trader mechanism, in order to maintain power system security and reliability.

Historical summary of directions

Figure 5.8 sets out the number of power system directions issued by AEMO in the last ten years to maintain the power system in a reliable or secure state. In 2016-17 ten directions were issued by AEMO.[346] This is the most directions issued since 2008-09. Over the past decade AEMO directions have been rare occurrences in the NEM.[347]

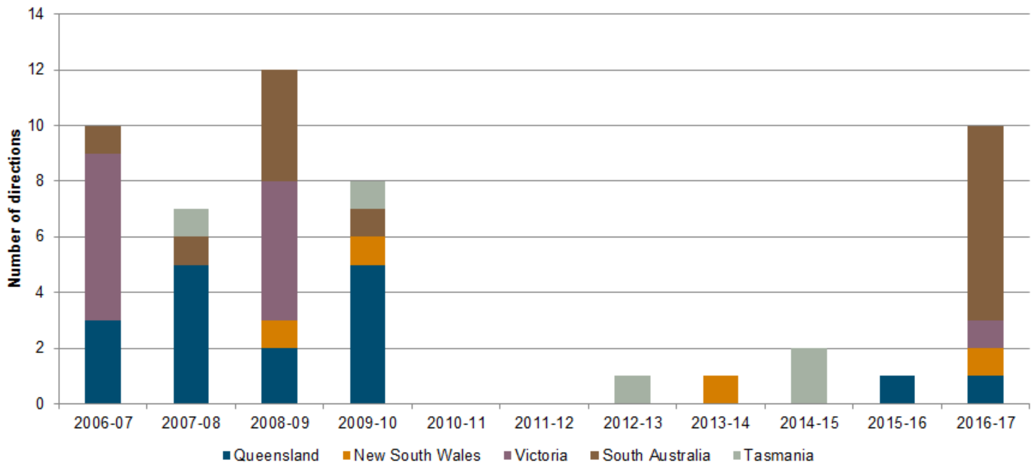
As mentioned in section 4.1.3, in 2016/17 two of the ten directions issued were to maintain the system in a reliable operating state. The remaining eight directions were issued to maintain the system in a secure operating state.

network. Investigation of the failure of the Quarantine SRAS on 28 September 2016 concluded that the cause was related to the switching sequence used by ElectraNet to connect the small generating unit to the larger one.

346 This figure includes directions issued under Section 116 of the National Electricity Law. Section 116 directions may include directions as issued under clause 4.8.9 of the rules (e.g. directing a scheduled generator to increase output) or clause 4.8.9 instructions (e.g. instructing a network service provider to load shed). The Panel understands that 10 February 2017 was the first instance of a direction being issued under section 116 of the National Electricity Law. AEMO have confirmed that they now issue system security directions under section 116 of the National Electricity Law and reliability directions under clause 4.8.9 of the NER.

347 In contrast, in 2005/06 61 directions were issued, while in 2004/05 42 directions were issued.

Figure 5.8 Directions issued in the NEM



Source: AEMO

Directions issued in 2016/17 to maintain the system in a secure operating state

Instances in 2016/17 where directions were issued to maintain the power system in a secure operating state include:

- **9 and 11 October 2016, South Australia:** During the spot market suspension in South Australia that followed the black system event there was a power system security requirement to maintain a minimum of three thermal synchronous generating units, each of not less than 100MW installed capacity, on-line at all times. Two directions were issued to generators:[348]
  - 9 October 2016, one of three thermal synchronous generating units online in South Australia advised AEMO that it would be unavailable from 12.00am on 10 October 2016 due to gas supply issues. AEMO contacted all other offline thermal synchronous generating units to seek their generation availability. Only one confirmed it was able to meet the requirement to synchronise generation in time, and advised it would only be available under a direction by AEMO. As a result, AEMO issued a direction to this generating unit at 8.54pm on 9 October 2016 to synchronise and run to minimum load by 12.00am until 5.30am on 10 October 2016.
  - 11 October 2016, one of the three South Australian thermal synchronous generating units available for dispatch between 9.00pm and midnight advised AEMO that it would bid "unavailable" from the energy market due to uneconomic dispatch. Three generating units confirmed they were able to meet the requirement to synchronise generation and generate to their technical minimum load by 9.00pm on 11 October 2016 under a direction by AEMO. At 4.16pm on 11 October 2016, AEMO issued a direction to one

348 AEMO, *NEM Event - Directions to thermal synchronous generators during South Australia market suspension*, 9 and 11 October 2016, April 2017.

synchronous generating unit that met the requirement based on least cost.[349]

- **1 December 2016, Separation event Victoria and South Australia:** As described in section 5.2.2 a separation event occurred between 1.15am and 5.00am on 1 December 2016 when South Australia separated from the rest of the mainland. A number of directions were issued in relation to this event:
  - At 1.15am on 1 December 2016 AEMO issued a direction to a generator in South Australia to provide up to 10MW of Fast Raise FCAS.[350]
  - At 2.30am on 1 December 2016 AEMO directed a generator in South Australia to provide other services, to reduce output, and a second direction at 3.00am as a counter-action to this prior direction.[351] Compensation payments of $254,703, $32,949 and $125,553 were made to participants.[352]
- **1 December 2016, South Australia:** At 10.21am on 1 December 2016, AEMO issued a direction to reduce generation at Mortlake Power Station Unit 12 in Victoria to ramp down to 0MW and desynchronise.[353] The direction was required to reduce the flow from South Australia to Victoria on the Heywood Interconnector below the limit of 250MW.[354]
- **28 and 29 March 2017, Queensland:** At 2.25pm on Tuesday 28 March 2017, AEMO reclassified the loss of multiple transmission lines between Nebo and Ross as a credible contingency due to tropical cyclone Debbie. For the period of the reclassification, AEMO applied a network constraint to limit the Ross cutset flow to be equal to or less than 260MW. AEMO issued directions to Mt Stuart Units 2 and 3, as there was insufficient market response to maintain this 260MW limit. Total compensation payments of $816,094 were made to participants.[355]
- **25 and 26 April 2017, South Australia:** For South Australia to be in a secure operating state, there is a power system security requirement for a minimum number of synchronous generating units connected to the 275kV network to be

349 Intervention pricing was not implemented on 9 October 2016 or 11 October 2016. The directions were issued during a period of market suspension when the South Australian spot price was determined by the Market Suspension Default Pricing Schedule in accordance with rules clause 3.14.5(l).

350 Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016,* June 2017, p. 3.

351 Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016,* June 2017, p. 3.

352 Synergies Economic Consulting, *Final Report on additional compensation claims arising from AEMO directions on 1 December 2016*, August 2017, p. 21.

353 AEMO, *NEM Event - Direction to Mortlake generating unit 12 – 1 December 2016*, November 2017.

354 In terms of associated costs, energy prices in South Australia reached the market price cap of $14,000/MWh between (and including) the dispatch intervals ending 10:00am and 10:20am when Mortlake Unit 12 was online. The high flows across the Heywood Interconnector from South Australia to Victoria during this period resulted in expensive generation in South Australia being dispatched, resulting in the high prices.

355 Harding Katz, *Compensation for Directions in Queensland on 28 and 29 March 2017*, September 2017, p. 1.

on-line at all times in South Australia. AEMO determined that this power system security requirement would not be met from 3.00am on 25 April 2017. AEMO issued two directions to participants in the South Australia. The first direction was issued at 2.34am on 25 April 2017. The second direction was issued at 7.45am on 25 April 2017. Compensation payments of $115,783 and $214,568 were made to participants.[356]

The Panel recognises that if stress on the system stemming from reliability incidents is not alleviated early enough it may result in directions being issued for system security. The 8 February 2017 reliability incident in South Australia (described in section 4.2) resulted in AEMO issuing a direction to shed load to maintain the system in a secure operating state.

The Panel notes that in addition to compensation payments, directions also lead to pricing inefficiencies and sub-optimal dispatch that culminate in higher costs being experienced by consumers.[357]

5.2 Major system security events

Four events have been selected by the Panel to illustrate the extent of potential supply and cost impacts for consumers following major security events in the power system. These events include:

- Black system event in South Australia on 28 September 2016
- Separation event and load shedding in South Australia and Victoria on 1 December 2016
- Multiple contingency event and load shedding in New South Wales on 10 February 2017
- Non credible contingency event in South Australia on 3 March 2017

The event descriptions below draw heavily on the relevant AEMO incident reports.

5.2.1 28 September 2016, South Australia

On 28 September 2016, a black system event occurred in South Australia in which the entire region, some 850,000 customers, lost electricity supply.[358] Briefly, the incident involved:[359]

- Tornadoes damaged transmission infrastructure causing faults on the network. These faults led some wind generators to reduce output and others to trip off, due to the response of wind farm fault-protection settings (specifically, pre-set

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356 Synergies Economic Consulting, *Final report on claims for additional compensation arising from directions on 25 April 2017,* September 2017, p. 3.

357 The out of market commitment of synchronous generators to maintain the system in a secure state results in less demand being met by intermittent generation that traditionally bids into the market at low prices.

358 A black system is defined in Chapter 10 of the rules as follows: "The absence of voltage on all or a significant part of the transmission system or within a region during a major supply disruption affecting a significant number of customers."

359 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017

ride-through limits). This loss of generation in South Australia resulted in an immediate compensating increase of imports from Victoria on the Heywood interconnector, with a combination of high currents and low voltages, culminating in the trip of the Heywood interconnector and the separation of South Australia from the NEM.

- Without any substantial load shedding following separation, the remaining generation was much less than the connected load and unable to maintain the islanded system frequency. As a result, all supply to the region was lost at 4.18pm.
- About 40 per cent of the load in South Australia capable of being restored had been restored by 8.30 pm, and 80 to 90 per cent had been restored by midnight. The restoration process was complicated by the failure of both South Australian SRAS generators.
- South Australian businesses suffered costs of $450 million as a result of the black system.[360]

Key Details

1. Two tornadoes almost simultaneously damaged a single circuit 275kV transmission line and a double circuit 275kV transmission line. The lines were 170 km apart.
2. The damage to these three transmission lines caused them to trip, and a sequence of faults in quick succession resulted in six voltage dips on the grid over a two-minute period at around 4.16 pm.[361]
3. As the number of faults on the transmission network grew, nine wind farms exhibited a sustained reduction in power as a protection feature activated. A sustained generation reduction of 456MW occurred over a period of less than seven seconds.
4. The reduction in wind farm output caused a significant increase in imported power flowing through the Heywood Interconnector. Approximately 700ms after the reduction of output from the last of the wind farms, the flow on the Heywood Interconnector reached such a level that it activated a special protection scheme that tripped the interconnector offline.
5. The South Australian power system then became separated (“islanded”) from the rest of the NEM. Without any substantial load shedding following the system separation, the remaining generation was much less than the connected load and unable to maintain the islanded system frequency. As a result, all supply to the region was lost at 4.18 pm.[362]
6. AEMO and ElectraNet assessed what sections of the network were safe to energise, after which a system restart plan began at 4.30 pm, including restart

360 Parliament of South Australia, *Report of the select committee on the statewide electricity blackout and subsequent power outages*, 28 November 2017, p. 12.

361 When a transmission line is damaged there is a short circuit (fault) and the line must be disconnected to protect the remainder of the system (known as a “trip”). However disconnection cannot occur instantaneously and so for a fraction of a second there is voltage dip (disturbance).

362 The supply demand imbalance was in the order of 1,000 MW, for a regional demand of 1,826 MW

capability from Quarantine Power Station (one of two contracted South Australian SRAS generators), and supply from Victoria via the Heywood Interconnector.[363] Mintaro Power station, the other contracted SRAS generator, tripped soon after starting.[364]

7. The first customers had power restored by 7.00 pm on 28 September. About 40 per cent of the load in South Australia capable of being restored had been restored by 8.30 pm, and 80 to 90 per cent had been restored by midnight. The remaining load was gradually restored as fallen transmission lines were bypassed, and all customers had supply restored by 11 October 2016.

8. Within minutes of the event, AEMO declared the NEM suspended in the South Australia region. The market was suspended until the 11 October 2016 due to continuing uncertainties in power system operations.

AEMO's conclusions from its investigations

Access to correct technical information about grid-connected equipment is critical for system security. Many wind farms in South Australia (and the NEM) have a protection feature that takes action if the number of ride-through events in a specific period exceeds a pre-set limit. Each wind turbine then either disconnects from the network, stops operating (remains connected with zero output), or reduces its output. AEMO concluded that it was the action of this "control setting responding to multiple disturbances that led to the black system".[365] Figure 5.9 shows the decline in wind farm power output.

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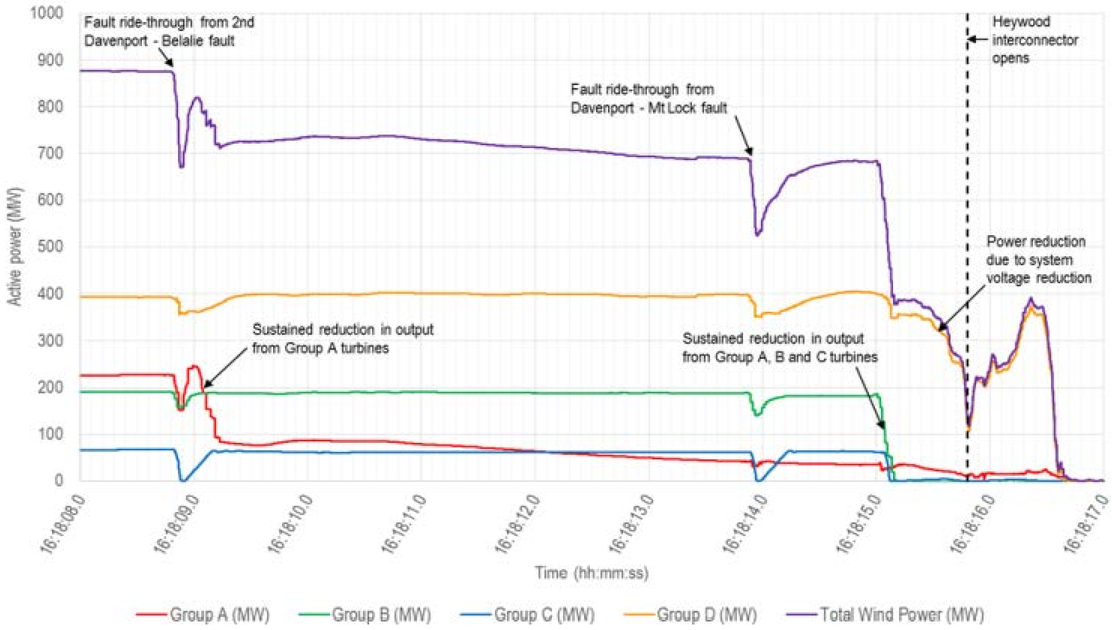
363 Due to problems with SRAS from Quarantine Power Station, the provision of auxiliary supply from the SRAS was not completed before supply to the Torrens Island area was made available from the Heywood Interconnector.

364 AEMO notes this did not delay the restoration process because the generator cannot by itself restore large generating units in the Torrens Island area.

365 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 7. Changes made to turbine control settings shortly after the event has removed the risk of recurrence given the same number of disturbances

Figure 5.9 Wind farm power reduction[366]



Source: AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 46.

AEMO considered whether the sustained power reduction in wind farm output was due to excessive wind speed.[367] Of the 456MW sustained power reduction by nine wind farms, approximately 35MW of wind generation was disconnected due to excessive wind speed during the last five voltage disturbances. AEMO concluded that this was not a material contributor to the event.

Had the generation deficit not occurred, AEMO's modelling indicated South Australia would have remained connected to Victoria and the black system would have been avoided. AEMO stated in its report that it could not rule out the possibility that later events could have caused a black system, but is not aware of any system damage that would have done this.

AEMO also reported that even after the clearance of all the faults, three wind farms reduced their reactive power injection and hence did not restore their respective connection point voltages. This behaviour was unexpected. AEMO noted that the existing generator performance standards under the rules do not include minimum requirements that would have prevented this response. This issue is being considered by the AEMC as part of the *Generator technical performance standards* rule change.

System security

The rapid reduction of wind farm output resulted in an immediate compensating increase of imports from Victoria on the Heywood interconnector. The total power flow across the Heywood interconnector as measured at the South East end was

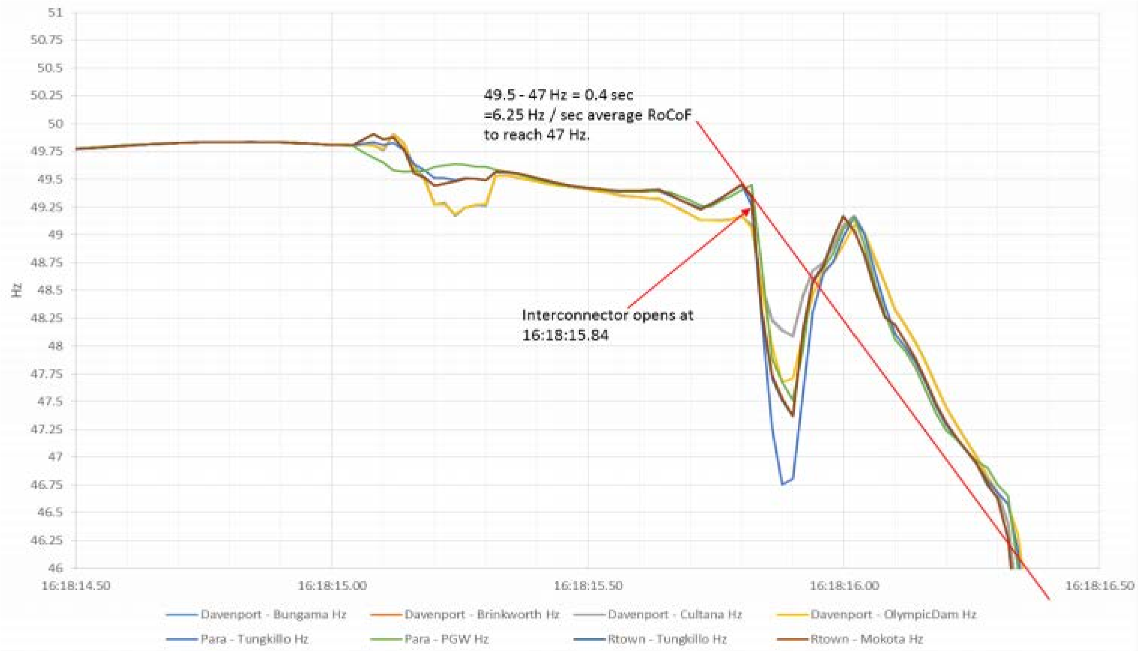
366 Wind farms have been grouped to better illustrate output reductions. Group A includes: Hallett, Hallett Hill, The Bluff, North Brown Hill, Clements Gap. Group B includes: Hornsdale, Snowtown North and South. Group C includes Mt. Millar. Group D includes: Lake Bonney 1, 2, 3, Canunda, Waterloo.

367 Typically, wind turbines exhibit a protective behaviour whereby they shut down to protect themselves from excessive mechanical stress in high winds, typically 90 km/h or more.

approximately 890MW (1,060MVA) at the onset of voltage collapse at 4.18pm. AEMO noted that it was a combination of high currents and low voltages that resulted in the activation of Heywood interconnector's automatic loss of synchronism protection mechanism at South East substation, leading to the disconnection of both of the transmission circuits of the Heywood interconnector.[368]

The trip of the Heywood interconnector meant the South Australian system was then islanded. A rapid decline in frequency then followed as 966MW of supply were lost (510MW import from Victoria on the Heywood Interconnector and 456MW of wind generation). Figure 5.10 shows the frequency and rate of change of frequency immediately before the black system at various nodes in South Australia.[369]

Figure 5.10 Frequency and rate of change of frequency immediately before the black system



Source: AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 37.

Historically, the rate of change of frequency following a separation between South Australia and Victoria has been below 3Hz/s, which has allowed under frequency load shedding to operate to maintain South Australian frequency above 47Hz and avoid a total black system.[370] However, during this event, the proportionally low amount of conventional synchronous generation dispatched in South Australia at the time of

368 When two areas of a power system, or two interconnected systems, lose synchronism, the areas must be separated from each other quickly and automatically to avoid equipment damage and to minimise the risk of spreading the disturbance.

369 Rate of change of frequency is proportional to the size of the sudden change in supply or demand as a result of the contingency event and inversely proportional to the level of system inertia at the time that the contingency occurs

370 47Hz is the lower bound of the extreme frequency tolerance limits nominated in the frequency operating standard.

separation, and the subsequent low inertia, resulted in a rate of change of frequency of approximately 6Hz/s.[371]

AEMO considered that the "key reason for the failure of the five on-line synchronous generators and five remaining wind farms to form a viable island was that frequency in various SA nodes fell rapidly following loss of the Heywood Interconnector".[372]

AEMO confirmed that once the frequency fell below 47Hz all supply to the region was lost with the remaining generation in South Australia tripping as would be expected.[373] Under rules clause S5.2.5.3, if the frequency drops below 47Hz in most parts of the South Australia island, synchronous generators and wind farms are not required to remain connected.

AEMO considers the following factors must be addressed to increase the prospects of forming a stable South Australian island and avoiding a black system:[374]

- Sufficient inertia to slow down the rate of change of frequency and enable automatic load shedding to stabilise the island system in the first few seconds. This will require increases in inertia in South Australia under some conditions, as well as improvements to load shedding systems combined with reduced interconnector flows under certain conditions.
- Sufficient frequency control services to stabilise frequency of the South Australian island system over the longer term. This will require increases in local frequency control services under some conditions.
- Sufficient system strength to control over voltages, ensure correct operation of grid protection systems, and ensure correct operation of inverter-connected facilities such as wind farms. This will require increases in local system strength under some conditions.

The AEMC has recently made two rules related to the provision of inertia and system strength in the NEM.[375]

System restoration

AEMO's conclusions relating to system restoration are detailed in section 5.1.6. The Panel notes that the failure of Quarantine Power Station to provide system restart

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371 The rate of change of frequency is proportional to the size of the sudden change in supply or demand as a result of the contingency event and inversely proportional to the level of system inertia at the time that the contingency occurs. The greater the size of the contingency event, or the lower the system inertia, the faster the frequency will change. Limiting the size of the rate of change of frequency provides: (i) a higher probability of generators remaining online following the occurrence of the contingency event; (ii) time for emergency frequency control schemes to operate effectively; and (iii) time for frequency control ancillary services in the islanded sub-network to respond and recover the frequency to normal operating levels.

372 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 68.

373 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 37.

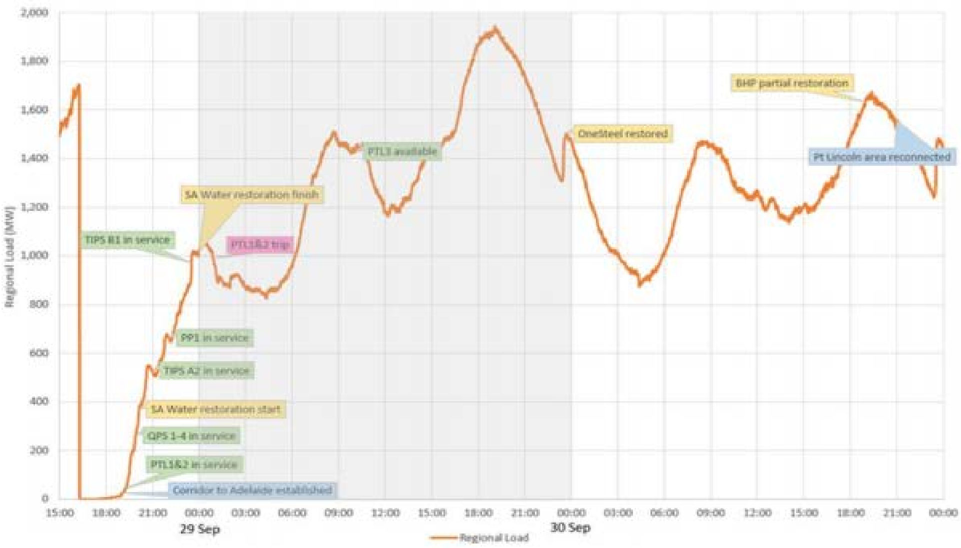
374 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 7

375 For more information see: http://www.aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels and http://www.aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque

ancillary services complicated and delayed the system restart process.[376] AEMO has stated that if the system restart services from Quarantine Power Station had operated as expected "clearance to restart the Torrens Island generating units would likely have been given approximately one hour earlier, at 5.30pm. AGL advised AEMO that if clearance to restart generating units had been given earlier, it is likely the generating units would have been returned to service earlier".[377]

Figure 5.11 shows the restoration of load profile that occurred following the black system event. Generally, it follows that if the Quarantine SRAS had been available and able to contribute to the system restart, the curve in Figure 5.11 may have shifted to the left, representing an earlier restoration of supply to consumers.

Figure 5.11 Restoration of load following black system event



Source: AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 76.

Market suspension

AEMO's key conclusion related to the market suspension is that "there is a lack of detailed procedures on how to operate the power system under extended periods of market suspension".[378]

In light of the black system, AEMO made 19 recommendations. A summary table of these recommendations is provided in appendix F

Panel's consideration

The Panel recognises that the South Australian network was subject to extreme and rare weather conditions on the day of the black system event.

376 Provision of SRAS from Quarantine Power Station is a staged process: (i) one of the smaller generating units is used to start the larger Quarantine unit; (ii) the larger generating unit is then used to energise the auxiliary supplies of other power stations in the South Australian power network. Investigation of the failure of the Quarantine SRAS on 28 September 2016 concluded that the cause was related to the switching sequence used by ElectraNet to connect the small generating unit to the larger one.

377 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 72.

378 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 8

There are a number of important lessons to be learned from this event. The unexpected reduction in wind generation due to protection control settings emphasises the importance of clear and current generator technical performance standards. Following the event, one of AEMO's key recommendations was to propose to ESCOSA changes to generator licensing conditions, and also to request similar changes to the rules, to address deficiencies in performance standards identified through its investigation of the black system.[379] The AEMC is currently considering perceived issues with current generator access standards through the *Generator technical performance standards* rule change.[380]

The high rate of change of frequency experienced during the incident highlights the challenges associated with maintaining a low inertia system. The delay in restoration attributed to the failure of system restart services also suggests improvements to the restoration process (including the testing of SRAS units) are required.[381] Issues in relation to the rate of change of frequency are being addressed in the AEMC's *Frequency control frameworks review*.

The Panel notes that work has been completed and is underway addressing these issues. It also notes the system restoration timeframe for the South Australia black system event compares favourably with international restoration timeframes.[382]

The Panel notes the AER has commenced its examination of participant compliance and system operation both during and in the lead up to the black system event, and in the subsequent period of market suspension.[383] The AEMC has also been asked by the COAG Energy Council to complete a review of the black system event identifying any systemic issues that contributed to the event or affected the response. The AEMC's review is to be progressed once the AER's compliance review is completed.

Costs associated with the event

A survey conducted by Business SA estimated the total cost of the state-wide blackout to all South Australian businesses was $450 million.[384] The impacts of the state-wide blackout were found to be disproportionately felt in South Australia's regions with the

379 AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 9

380 For more detail refer to section 5.4.10.

381 The Panel notes a number of submissions (Small Business Commissioner, Conservative Council of SA) to the South Australian Parliament Select Committee's inquiry into the black system event were "critical of AEMO's lack of knowledge of the protection settings on wind turbines, which caused them to trip... and the failure of the System Restart Ancillary Services, purchased by AEMO, to operate effectively, causing delay in recovering from the black system." Parliament of South Australia, *Report of the select committee on the statewide electricity blackout and subsequent power outages*, 28 November 2017, p. 14

382 For example, 6.5 hours were required to restore 80 per cent of load following a blackout in Turkey in 2015 and 15 hours were required to restore 80 per cent of load following a blackout in Hawaii in 2008. AEMO, *Black system South Australia 28 September 2016, final report*, March 2017, p. 77.

383 The AER's review is discussed in more detail in section 5.4.11.

384 Business SA is South Australia's largest membership-based employer organisation. Parliament of South Australia, *Report of the select committee on the statewide electricity blackout and subsequent power outages*, 28 November 2017, p. 12.

survey finding the cost of the extended blackout to the Eyre Peninsula was $8.3 million.[385]

The Panel notes that SACOME, in its submission to the 2017 AMPR, highlighted discussions with its members that "estimated that the impact of the Black System and other supply interruptions to the resource sector across the past 12 months to be approximately $230 million".[386] This includes cost of lost production, plant maintenance and repairs.[387]

BHP estimated that the electricity system instability in South Australia would cost Olympic Dam US$135 million in 2016/17, including US$105 million in lost production during the 14 day outage resulting from the black system. [388]

The Australian Industry Group stated that "the black system has had a powerful and negative effect on business perceptions of the rusk and viability of operating in SA".[389]

Box 5.1 Societal impacts of South Australian black system event

While the black system event had significant economic costs, there were additional costs on the community associated with the event. The Panel has presented the following case study to illustrate these costs.

During the widespread power outage, back-up generators at Adelaide's Flinders Medical Centre operated for an hour before failing. The back-up power failure was caused by a broken fuel pump despite the system being tested earlier in the week. As a result, 17 patients had to be transferred to another hospital.[390] Life-support machines (such as, ventilators) reverted to battery power when the generators cut out.[391] Elective surgeries had to be postponed. The failure of backup generators also meant that tragically a number of embryos at Flinders Fertility, a private clinic situated in the Flinders Medical Centre were lost.[392] At least 12 patients suffered lost embryos.

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385 Parliament of South Australia, *Report of the select committee on the statewide electricity blackout and subsequent power outages*, 28 November 2017, p. 12

386 SACOME submission p. 5.

387 One facility had damage to their processing equipment and all had a material decrease in production of 15-18 per cent.

388 Parliament of South Australia, *Report of the select committee on the statewide electricity blackout and subsequent power outages*, 28 November 2017, p. 13

389 The Australian Industry Group is Australia's peak industry association. Parliament of South Australia, *Report of the select committee on the statewide electricity blackout and subsequent power outages*, 28 November 2017, p. 13

390 SBS News, *Adelaide hospital's back-up power fails, 29 September 2016,* Accessed on 29 December 2017 at: https://www.sbs.com.au/news/adelaide-hospital-s-back-up-power-fails

391 Batteries back-up supplies can last for a number of hours.

392 ABC News, *SA weather: Embryos destroyed at Flinders Medical Centre after generator fails in blackout, 30 September 2016,* accessed on 29 December 2017 at: http://www.abc.net.au/news/2016-09-30/sa-storms:-embryos-destroyed-when-clinic-generator-fails/7891946

The Local Government Association of South Australia identified a number of impacts of the state-wide blackout on local communities, including:[393]

- inability to access ATMs or use credit cards for transactions
- shortages of water and fuel
- loss of telecommunication services.

Some of these impacts were felt most severely by households and businesses in the Eyre Peninsula where the blackout lasted for several days.

5.2.2 1 December 2016, South Australia and Victoria

On 1 December 2016 a separation event and load shedding occurred in South Australia and Victoria. The incident involved:[394]

- The trip of the Moorabool–Tarrone 500kV transmission line. The trip:
  - severed the Heywood interconnection between South Australia and Victoria, and
  - left the Portland Aluminium Smelter (APD) connected to the South Australian network.
- The operation of South Australia Power Networks' under frequency load shedding scheme, which disconnected approximately 190MW of load in South Australia.[395] Supply was made available after 38 minutes.
- The operation of the Emergency APD potline tripping scheme, disconnecting all of the APD load (473MW). Supply was made available after three hours and 14 minutes.

The power system was not in a secure operating state after this incident for a period of four hours and 20 minutes.

Key details

1. Figure 5.12 shows that immediately prior to the incident, there were two planned outages:
   (a) Outage of the Heywood No. 2 500kV busbar. This outage resulted in only a single connection from Victoria to SA via the Heywood Interconnector.[396]
   (b) Outage of the Heywood–APD No. 2 500kV transmission line. This outage resulted in load to APD being supplied via a single connection.

393 Local Government Association of South Australia, *Review of the Extreme Weather Event South Australia September 2016 - LGA submission to the review*, December 2016.

394 AEMO, *Final report, South Australia Separation Event, 1 December 2016*, 28 February 2017.

395 There was also an additional load reduction of 40MW that was not associated with the operation of the under frequency load shedding scheme. ElectraNet have advised AEMO that this load reduction occurred at Prominent Hill in the northern part of the state. Neither ElectraNet nor AEMO are aware of any load shedding scheme (frequency or voltage) in this area.

396 The Murraylink interconnector was in service and operating normally.

2. At 12.16am, a single phase to earth fault occurred on the Moorabool–Tarrone 500 kV transmission line, causing the line to trip at both ends.[397] This fault was the result of equipment failure.
3. The power flow on the Heywood interconnector was initially 217MW towards South Australia. Immediately after the faulted line tripped, the power flow reversed with 480MW flow from South Australia to supply the load at APD.
4. Shortly after the initial fault, the emergency APD Potline tripping scheme disconnected the APD load from South Australia.[398] This reduced the flow on the Heywood interconnector to zero.
5. The sudden loss of supply to South Australia resulted in the frequency falling to 48.23Hz. South Australia Power Networks' under frequency load shedding scheme operated to shed around 190MW of load. There was also an additional load reduction of around 40 MW that was not associated with operation of the under frequency load shedding scheme. The under frequency load shedding scheme operated as expected.[399]
6. At 12.54am, AEMO gave permission to restore all the load in South Australia.[400]
7. Supply was made available to APD within three hours and 14 minutes (at 3.30am), but APD advised AEMO they were not ready to commence load restoration. At 4.47am, APD advised AEMO they were ready to restore load and AEMO gave APD permission to restore all load.

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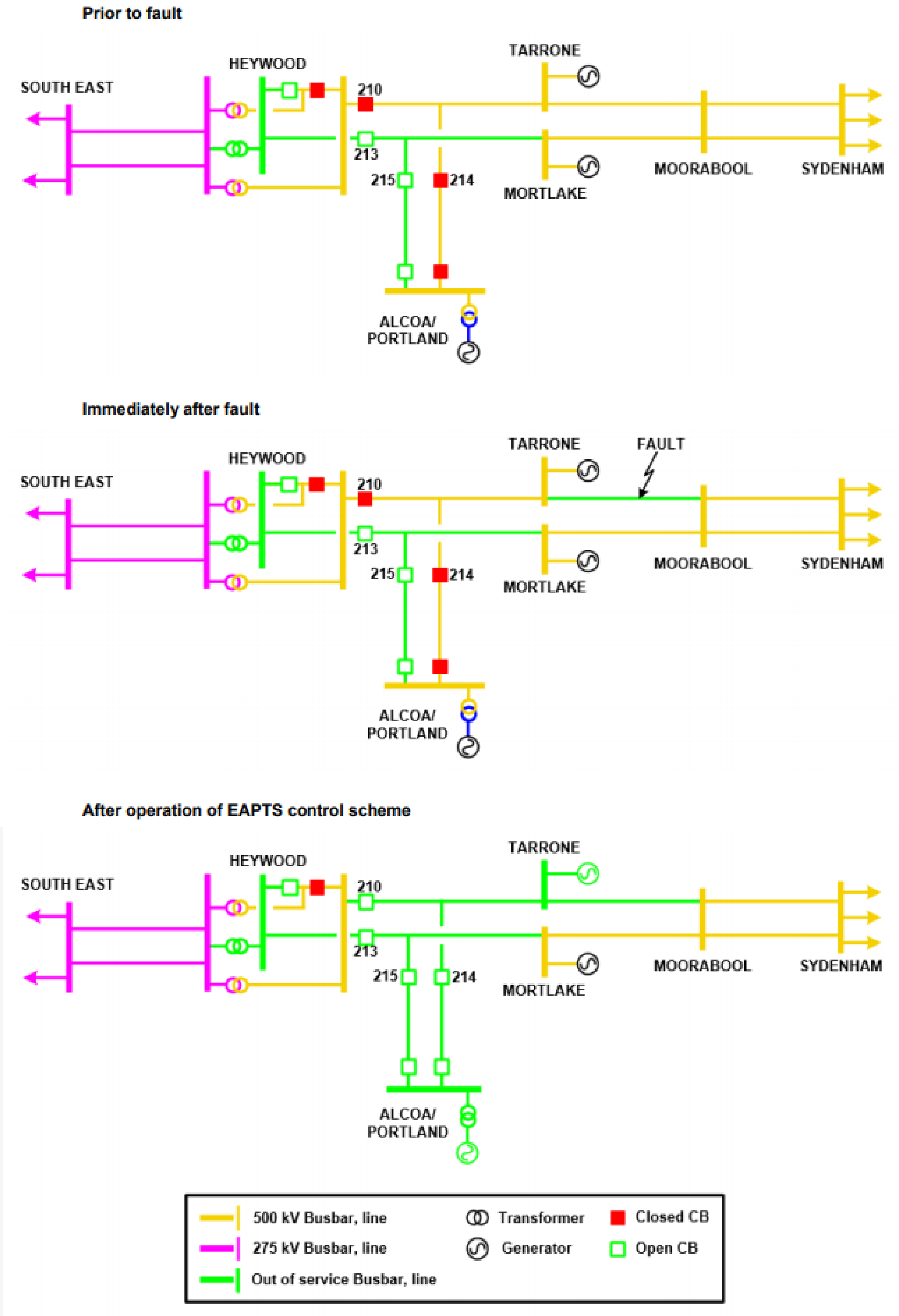
397 This is one of the most common faults and occurs when there is a short circuit between one conductor and ground. Electronics hub, *Types of Faults in Electrical Power Systems*, accessed 21 December 2017 at: https://www.electronicshub.org/types-of-faults-in-electrical-power-systems/#Short_Circuit_Faults

398 The emergency APD potline tripping scheme is in place to ensure the APD load is not fed from South Australia after the loss of the transmission connection between Moorabool and Heywood.

399 To stabilise the separated South Australian power system, AEMO directed ElectraNet to reduce supply to BHP Billiton's Olympic Dam site to approximately 100MW, under a 2015 protocol agreed by AEMO and BHP Billiton for such events. Prior to the event, BHP Billiton's Olympic Dam site was consuming approximately 170MW. The duration of this reduction was three hours and seven minutes.

400 All load in South Australia was restored within 89 minutes, by 1.45am.

Figure 5.12 System diagram



Source: AEMO, *Final report, South Australia Separation Event, 1 December 2016,* 28 February 2017, p. 14.

Non-delivery of FCAS immediately following the separation event

Pelican Point Power Station did not provide fast raise (R6) FCAS immediately after the separation event as required.[401] AGL was unable to provide the high speed data to

401 AEMO is working with Engie to determine the reasons for this.

enable AEMO to analyse the delivery of fast raise (R6) FCAS from the Torrens Island generating units.[402]

AEMO reported the power system was not in a secure operating state for the duration of this incident (four hours and 20 minutes), as no additional fast raise (R6) FCAS was available, and the output of Pelican Point Power Station could not be further reduced to lower FCAS requirements.[403]

In its incident report, AEMO stated that "the non-delivery of FCAS did not have a material impact on the outcome of this incident".[404]

Costs associated with the incident

This incident caused molten aluminium in one of the two smelter potlines at APD to cool and solidify (more than 200 smelting pots).[405] The power outage left the smelter operating at about one-third capacity, costing Alcoa an estimated $1 million a day in revenue.[406] APD was not restored to full capacity until October 2017.[407]

5.2.3 10 February 2017, New South Wales

On 10 February 2017 in New South Wales there was a multiple contingency event with all four Colongra units (667MW in total) failing to start when required. The incident also involved:[408]

- High demand conditions driven by extreme temperatures in New South Wales.[409]
- Reduced thermal generation capacity with a forced outage at Tallawarra power station (420MW) and two of Liddell's four units (over 800MW) also unavailable.
- A direction from AEMO to Transgrid to shed a potline at Tomago aluminium smelter (290MW) for 63 minutes.

Key details

Coincident with the peak of demand for the day, the following also occurred on 10 February:[410]

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402 AGL advised the data could not be provided due to a software problem with their data recorders. AGL has advised that the software problem has been resolved.

403 AEMO, *Final report, South Australia Separation Event, 1 December 2016*, 28 February 2017, p. 11.

404 AEMO, *Final report, South Australia Separation Event, 1 December 2016*, 28 February 2017, p. 12.

405 APD is Victoria's single largest electricity user.

406 John Dagge, Herald Sun, *Alcoa gets $230m lifeline for Portland aluminium smelter*, 21 January 2017 accessed at: http://www.heraldsun.com.au/business/alcoa-gets-230m-lifeline-for-portland-aluminium-smelter/news-story/ae176cb7230accfbfc7aba5948f699d7

407 AAP, SBS news, *Vic Alcoa smelter completes restart*, 12 October accessed: https://www.sbs.com.au/news/vic-alcoa-smelter-completes-restart

408 AEMO, *System event report, New South Wales, 10 February 2017*, 22 February 2017.

409 Temperatures at Bankstown reached 42.9 degrees in the early afternoon.

410 Note all times listed are in market time (AEST). In February New South Wales is market time plus 60 minutes.

1. The forced outage of Tallawarra generators (408MW).
2. Colongra units unable to start (600MW).
3. A number of thermal generators reducing output.
4. Reducing wind and solar PV generation of approximately 300MW between 5.00pm and 6.00pm (approximately in line with forecasts).

These factors, all coinciding at approximately 5.00pm, combined to overload the New South Wales interconnections with Queensland and Victoria, creating an insecure operating state.[411] With no further generation available to serve the demand and relieve the overloading interconnectors, the state reached an LOR3 condition at 4.50pm. As a last resort at 4.58pm AEMO instructed TransGrid to reduce demand at the Tomago aluminium smelter (290MW) to restore the power system in New South Wales to a secure operating state.[412] The instruction was issued to restore load one hour later.

Multiple contingency event

The four Colongra generating units received an instruction to start generating at 4.25pm, but all the units tripped when they were started on fuel oil.[413]

AEMO have confirmed the failure of all four Colongra units to start when required represents a multiple contingency event.

A multiple contingency event is defined in the frequency operating standard as "either a contingency event other than a credible contingency event, a sequence of credible contingency events within a period of 5 minutes, or a further separation event in an island."[414]

The Panel notes a multiple contingency event is excluded from calculations of unserved energy.

High demand

The Panel notes the extreme nature of the conditions on the day in question. Temperatures at Bankstown reached 42.9 degrees in the early afternoon. These high temperatures, falling on a weekday in the middle of February – ie, beyond the summer holiday period when demand tends not to reach as high levels because many businesses and schools are shut down – represent an extreme demand event. Demand peaked at 4.30pm at 14,181MW.[415]

Also of note, the New South Wales Government initiated a media campaign on 9 February to advise customers of potential electricity shortages on 10 February and encourage customers to reduce electricity consumption where possible. AEMO believes this initiative may have resulted in demand being approximately 200MW lower across

411 From 4.30pm, the flow on QNI was 276MW above normal limits, Terranorra was operating at 126MW above normal limits and the Victoria-NSW interconnector was operating at 297MW above normal limits.

412 The Tomago aluminium smelter is New South Wales' largest consumer of electricity.

413 The units were started on fuel oil as gas supply was very low.

414 Reliability Panel, *Frequency operating standard*, November 2017, p. 10.

415 The New South Wales record peak operational demand occurred on 1 February 2011, and was 14,744MW.

the peak afternoon period, however, AEMO cannot measure or verify the impact of the initiative or differentiate it from response of loads due to high spot market prices.

Thermal generator outages and reduced output

In addition to the failure of the Colongra generating units to start when required, the following thermal generators suffered outages or reductions in output:

- The Tallawarra CCGT unit tripped at 4.22pm from 408MW due to a fault in the gas turbine.[416]
- Two of Liddell's four units (over 800MW of generating capacity) were also unavailable due to boiler tube leaks.
- Eraring power stations had issues with plant temperature that limited its output by 340MW.
- Vales Point power station had issues with outlet temperature that limited its output by 90MW.

Costs associated with the incident

Direct costs associated with 10 February incident are not publically available. The Panel notes that after 75 minutes without power an aluminium smelter's potlines start to "freeze". After three hours without power potlines are damaged beyond repair. It has been reported that the replacement bill is $100 million per potline.[417]

5.2.4 3 March 2017, South Australia

A non-credible contingency event occurred on 3 March 2017 in South Australia. The incident:[418]

- involved a series of faults at ElectraNet's Torrens Island 275kV switchyard resulted in the loss of approximately 610MW of generation in South Australia across five generating units.
- featured a 400MW drop in demand in South Australia. It is important to note AEMO did not instruct load shedding, and there was no operation of the under frequency load shedding scheme.[419]
- almost resulted in the trip of the Heywood interconnector, and a repeat of the black system event that occurred on 28 September 2016 - this was averted as voltage levels at the South East substation were higher for this event than on 28 September 2016.

416 The Tallawarra unit's registered capacity is 440MW

417 Joanne McCarthy, *Tomago Aluminium is preparing for more power shutdowns this summer*, Newcastle Herald, 13 September 2017, accessed at: http://www.theherald.com.au/story/4919006/smelters-100m-decision/

418 AEMO, *Fault at Torrens Island switchyard and loss of multiple generating units, 3 March 2017,* 10 March 2017

419 The under frequency load shedding scheme was not expected to operate as the frequency remained above 49Hz

Key details

1. Demand in South Australia was moderate, 1993MW of which 549MW was supplied by input from Victoria.
2. This non-credible contingency was initiated at 3.03pm by the explosive failure of a capacitor voltage transformer in the Torrens Island 275kV switchyard.[420]
3. The loss of generation at Pelican Point Power Station was unexpected, and was caused by an unexplained protection operation within ElectraNet's switchyard at Pelican Point.[421]
4. Torrens Island Power Station B3 generating unit tripped, likely due to debris/smoke from explosion of the capacitor voltage transformer.[422]
5. The loss of the Torrens Island Power Station B2 unit was unexpected, and was caused by the failure of the boiler air heater drive.[423]
6. The total loss of generation for this event was 610MW, however 410MW was lost within 1.5 seconds of the initial fault. The remaining 200MW was lost over a period of between one to five minutes after the initial fault.
7. The power system in South Australia was not in a secure operating state for 40 minutes.
8. There was a reduction in demand coincident with the faults at the Torrens Island switchyard. The initial reduction was 400MW, which rapidly reduced to around 250MW.[424]

Similarities to black system event

AEMO has identified that there are close similarities between this event and the black system event on 28 September 2016 in that there was a large sudden reduction of generation in South Australia that resulted in the power flow across the Heywood Interconnector exceeding normal operating limits.

AEMO notes:

> "Voltage levels at the South East substation were not as low as on 28 September 2016 – if they had been lower, the Loss of Synchronism protection that disconnected the Heywood interconnector in that event may have operated again, resulting in another black system event."[425]

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420 Torrens Island Power Station B4 generating unit disconnected from 130MW.

421 Pelican Point GT 11 unit tripped from 150MW. The loss of this unit also resulted in the trip of the steam turbine from 70MW

422 Torrens Island Power Station B3 tripped from 130MW.

423 Torrens Island Power Station B2 tripped from 130MW.

424 AEMO believes, supported by information provided by ElectraNet, that this 150MW change was a consequence of rooftop PV systems shutting off in response to the voltage disturbance, producing a reduction in generation of 150MW and consequently an increase in demand. As the rooftop PV systems recovered and automatically re-connected, their output increased and reduced the demand.

425 AEMO, *Fault at Torrens Island switchyard and loss of multiple generating units, 3 March 2017,* 10 March 2017, p. 2. Part of the reason for the improved voltage response at the South East substation on 3

All wind farms in South Australia successfully rode through a series of three transmission faults in short succession, providing an initial indication that the changes made to their protection systems since 28 September 2016 have been successful. AEMO has not identified any sustained reduction in output from the wind farms as a consequence of the faults on the transmission system.

Panel's consideration

The Panel notes AEMO's conclusion that:[426]

> "AEMO could not have reasonably foreseen this event, as the near-simultaneous tripping of multiple generating units across separate power stations is an extremely rare event. "

The Panel notes AEMO's explanation that, if the Heywood interconnector had tripped:[427]

> "the rate of change of frequency (RoCoF) would have been approximately 8.7 Hz/s, and it would have been beyond the capability of the UFLS [under frequency load shedding] scheme in SA to shed sufficient load in time to prevent a black system. This relatively high RoCoF can be attributed to the proportionally low amount of conventional generation that remained on line after the event and the subsequently low inertia that would have occurred as a result."

5.3 Projections and emerging system security issues

In the context of falling levels of synchronous generation and changes in the way generating units are being operated, a number of system security issues have arisen. These issues include, but are not limited to:

- the degradation of frequency performance during normal operation
- decreases in available system inertia, resulting in increased challenges to maintain system frequency following disturbances
- declining system strength.

5.3.1 Degradation of frequency performance during normal operation

AEMO engaged DIgSILENT in May 2017 to investigate and report on the likely causes of the degradation of frequency performance in the normal operating frequency band, and report on the materiality of the issue and potential consequences.[428]

March 2017 is the load reduction that occurred as a result of the voltage disturbance caused by the fault.

426 AEMO, *Fault at Torrens Island switchyard and loss of multiple generating units, 3 March 2017,* 10 March 2017, p. 12.

427 AEMO, *Fault at Torrens Island switchyard and loss of multiple generating units, 3 March 2017,* 10 March 2017, p. 12.

428 DIgSILENT, *Review of frequency control performance in the NEM under normal operating conditions, final report,* 19 September 2017. This work was commissioned by AEMO to further the work of the Ancillary Services Technical Advisory Group.

AEMO have confirmed through DIgSILENT's analysis, and further monitoring and investigations, that:

- An increased incidence of exceedance events (where the power system frequency falls outside the normal operating frequency band) has occurred for both the NEM mainland and Tasmania.[429]
- A small number of slow, unstable frequency oscillations have been observed.[430]

DIgSILENT's analysis concluded that the root cause of the long term degradation of frequency performance is a reduction in the level of primary frequency control provided during normal system operation. Primary frequency control provides the initial response to frequency disturbances. DIgSILENT attributes reduced primary frequency control to a decline in governor response provided by generators within the normal operating frequency band.[431]

DIgSILENT's investigation reported that there are costs associated with maintaining primary frequency control within the normal operating frequency band and as the service is not paid for there is no incentive to provide the control service.[432] More specifically, drivers of reduced frequency control include: a reduction in plant efficiency ("wear and tear" costs), compliance with rules obligations and the regulation FCAS causer pays mechanism.[433]

The DIgSILENT investigation identified a number of risks associated with this reduction in primary frequency control and associated degradation of the frequency distribution. These risks include:[434]

- Impacts on generators:
  - an increase in the rate of wear and tear on mechanical generating equipment for those generators that respond to frequency changes

429 Refer to Figure 5.5 and Figure 5.6.

430 The confirmed events involved the undamped oscillation of the power system frequency by ±0.05Hz with a period of oscillation of around 25 seconds. The average frequency during these events was at the lower end of the normal operating frequency band (49.85 Hz – 50.15 Hz) and they persisted over multiple dispatch intervals, for around 5 - 10 minutes. Further investigation is required to determine the causes of these oscillatory events. DIgSILENT, *Review of frequency control performance in the NEM under normal operating conditions, final report,* 19 September 2017, pp. 34-35.

431 In the NEM, primary frequency control is only required to be provided by contingency FCAS, and is voluntarily provided by generator governor response.

432 There is no rule requirement for governor response, other than recorded in performance standards of some generators.

433 Compliance involves matters such as dispatch targets, contingency FCAS offers, performance standards. DIgSilent cited that compliance is more difficult if governors are responding to frequency changes. Causer Pays is the mechanism by which AEMO recovers the cost of regulation services. A lack of governor response in the power system will lead to higher levels of volatility in frequency, higher frequency deviations and time error, which in turn would lead to additional regulation FCAS services being enabled, at higher prices. This, in turn, can lead to higher amounts to be recouped from Causer Pays. DIgSILENT, *Review of frequency control performance in the NEM under normal operating conditions, final report,* 19 September 2017, p. 42.

434 DIgSILENT, *Review of frequency control performance in the NEM under normal operating conditions, final report,* 19 September 2017. pp. 45-46

— a decrease in the operational efficiency of mechanical generating equipment, especially where a generator continues to be responsive to frequency.

- Implications for system security:
  - increased potential for frequency oscillations
  - difficulty in AEMO meeting the performance standards set out in the frequency operating standard
  - potential for increased rate of change of frequency and maximum deviation in response to contingency events
  - increased variability of interconnector flow on network interconnectors following contingency events.
- An increase in FCAS costs as the quantities and utilisation of existing FCAS products increase to control power system frequency.

These issues are being considered by the AEMC's *Frequency control frameworks review*.

5.3.2 Inertia

Traditional large spinning generators are synchronised to the AC power system. This means that they rotate at the same speed as the frequency of the system. It also means that there is an electro-mechanical "link" between the mechanical energy of the generator and the electrical frequency of the power system. As the electrical frequency of the AC system increases, the generator will tend to spin faster, and as the frequency falls, the generator will slow down. This is referred to as the physical inertia provided by the generating unit.

This link means that a degree of physical inertia can be provided by some of the larger, heavier synchronous generators. This in turn means that in a system with lots of these heavy spinning units, any fall in the frequency caused by a disturbance will be slowed by the heavy spinning mass of the generator. In effect, the inertia of these synchronous units slows down the rate at which the frequency will change following a sudden disturbance to the power system, such as the sudden loss of a generator or load.

As demonstrated in chapter 3, a key trend in the NEM is that synchronous units are withdrawing from the market and in many cases being replaced with non-synchronous units. These non-synchronous units often do not provide the same kind of inertial response.[435] It follows that as synchronous generation is withdrawn from the power system, the level of inertia decreases, potentially resulting in faster rates of change of frequency following a disturbance to the power system.[436] Figure 5.13 shows the inertia of the mainland and Tasmanian systems.

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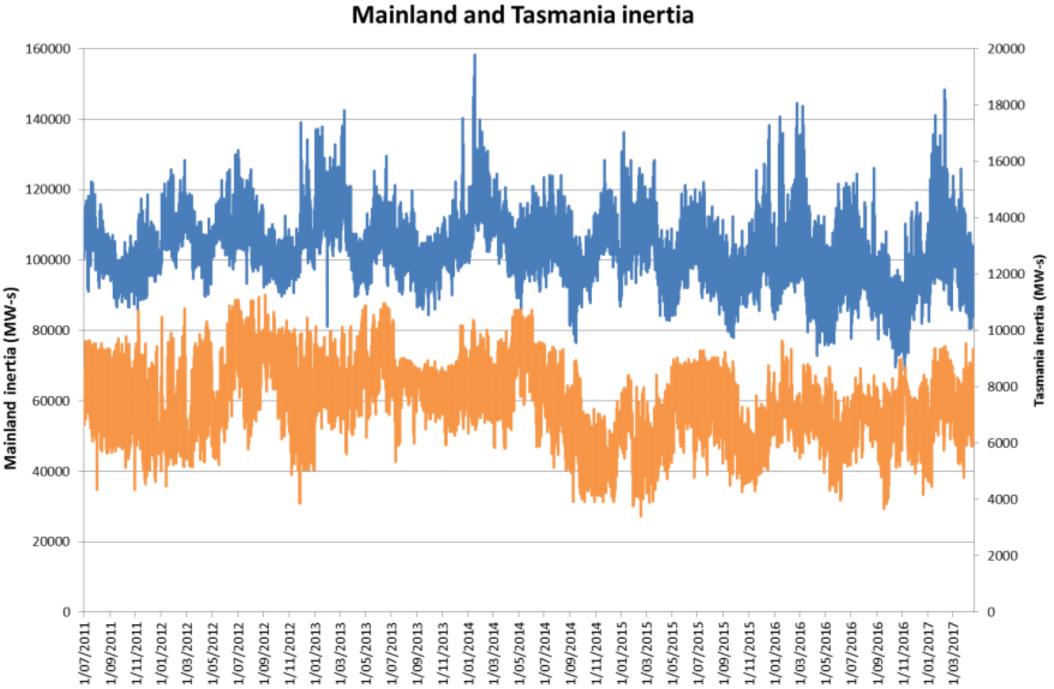
435 Non-synchronous units such as wind farms may be able to provide synthetic inertia. Synthetic inertia describes the capability of some wind farms to provide an inertial response in response to significant under frequency events with the rotational mass in the wind turbine used to provide a temporary power increase.

436 The rate of change of the frequency following a major disturbance is a product of both the level of inertia in the system, as well as the size of the disturbance.

Figure 5.13 Mainland and Tasmania power system inertia 2011 to 2017[437]



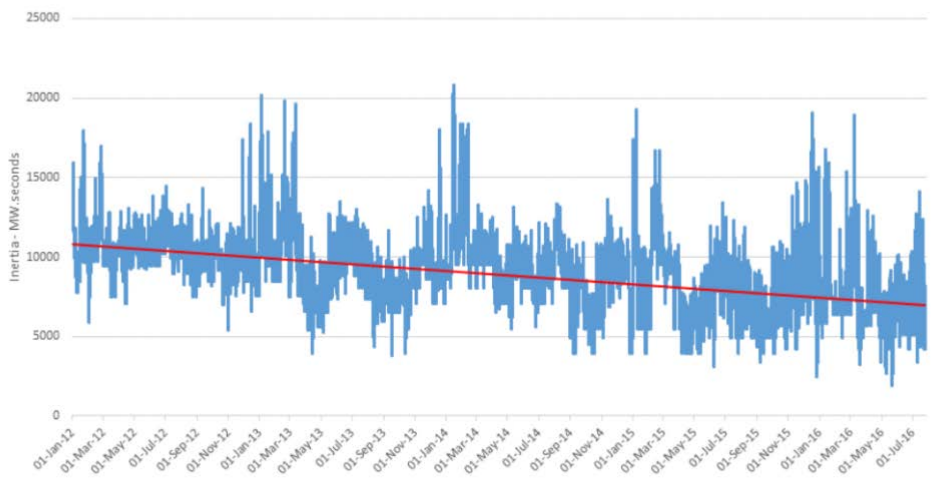
Source: DIgSILENT, *Review of frequency control performance in the NEM under normal operating conditions, final report*, 19 September 2017, p. 36.

Over the period there has been a decreasing level of system inertia for both the mainland and Tasmania.[438] The Panel concurs with DIgSILENT's consideration that this is "largely due to the change in the generation mix", specifically the withdrawal of synchronous thermal generation and increased penetration of non-synchronous generation. This trend is likely to continue as the fleet of coal fired generation ages and there is a large increase in the development of solar farms and wind farms and continued strong uptake of rooftop PV. This trend is most pronounced South Australia. The level of inertia in South Australia is shown in Figure 5.14.

437 The blue curve represents the level of system inertia in the mainland; the orange curve represents the level of system inertia in Tasmania.

438 The system inertia shows substantial seasonal variation which is greater than the reduction in system inertia over the period 2011 to 2017. The power system inertia tends to be lower in spring and autumn and higher in summer and winter, consistent with the seasonal demand. Historically spring tends to have the lowest inertia, because many large thermal plants are maintained during this time, in preparation for summer peak.

Figure 5.14 Inertia in South Australia, 2012 to 2016



Source: AEMO, *Future power system security program progress report*, August 2016, p. 21.

A certain level of inertia is necessary to maintain the rate of change of frequency to manageable levels.[439] In the case of non-credible contingencies, if the rate of change of frequency is sufficiently large, it can result in the load or generation "tripping" off the system. There is a risk that this may lead to a further worsening of the frequency disturbance. Furthermore, if the rate of change of frequency is large enough, emergency frequency control schemes may not be able to prevent a broader system disruption.

The procurement of the minimum levels of inertia required to maintain the system in a secure operating state has been addressed through *Managing the rate of change of power system frequency* final rule.[440]

5.3.3 Managing contingency events - rate of change of frequency

Fast frequency response refers to the delivery of a rapid active power increase or decrease by generation or load in a timeframe of two seconds or less, to correct a supply-demand imbalance and assist in managing power system frequency.[441] As part of its *Future Power System Security Program*, AEMO has published a working paper on fast frequency response in the NEM.[442] In this paper AEMO analysed the risk of potential exposure to high rates of change of frequency across the NEM following credible and non-credible contingency events. The objective of this analysis was to provide an indication of the timing of challenges in maintaining the frequency operating standard due to high rate of change of frequency, illuminating some of the potential opportunities for different fast frequency response services.[443]

439 This is the case in the NEM currently. Future technologies may be able to substitute for inertia.

440 Refer to section 5.4.4

441 Given fast frequency response can act quicker than current frequency control services in the NEM, it may also assist in managing challenges related to high rate of change of frequency.

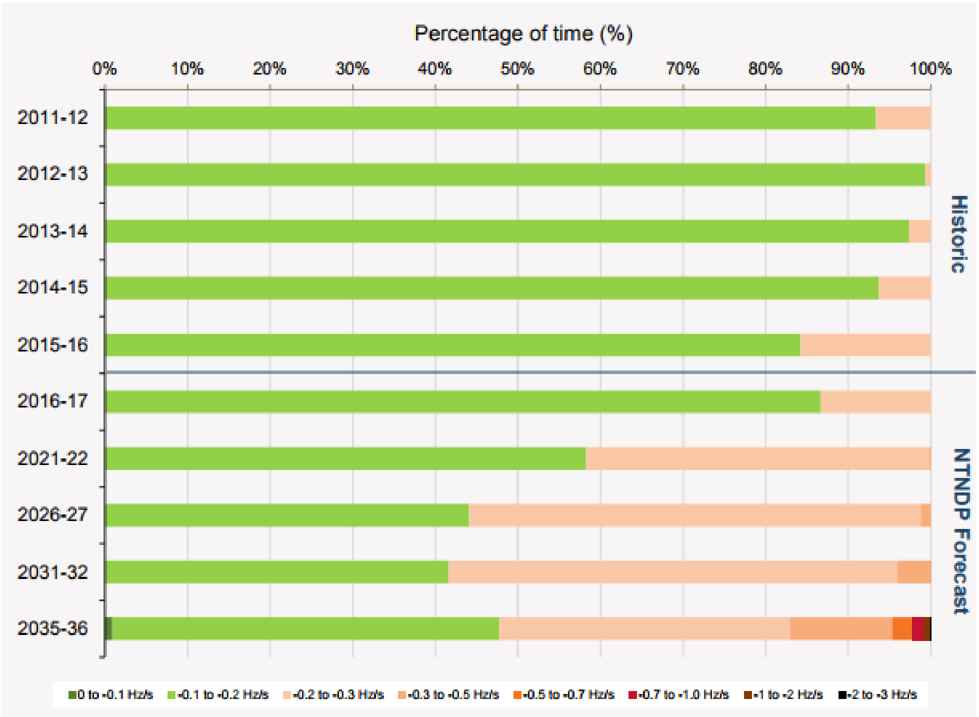
442 AEMO, *Fast frequency response in the NEM*, August 2017

443 The analysis was based upon the generation mix projected in the 2016 NTNDP.

Managing credible contingency events

Figure 5.15 shows the projected rate of change of frequency exposure related to credible contingency events for the NEM mainland. It shows that rate of change of frequency levels could be in the range of 0.2-0.3 Hz/s for more than 40 per cent of the time by 2021/22. At this level of rate of change of frequency, there is less than two seconds for primary frequency control actions to arrest the frequency decline before frequency leaves the containment band.[444] This is quicker than the commonly observed response from many synchronous governors, suggesting that the frequency operating standard may not be met in these cases. AEMO stated that this implies an increasing need for faster frequency services which, by 2021/22, could provide value on the NEM mainland in assisting with the management of credible contingency events.

Figure 5.15 Negative rate of change of frequency exposure for credible contingency events in the mainland NEM



Source: AEMO, *Fast frequency response in the NEM*, August 2017, p. 15.

Managing non-credible contingency events

The high rate of change of frequency following non-credible contingencies presents a number of risks to managing the power system including:[445]

- The increased likelihood of under frequency load shedding may mean more customers will be tripped. However, if the rate of change of frequency is too high, the relays on under frequency load shedding may not be able to respond fast enough to prevent a cascading failure.

444 For specifics on the containment band refer to the frequency operating standard. For the mainland the containment band is the NOFB in the absence of contingencies and 49.5 to 50.5Hz for generation or load event.

445 AEMO, *Fast frequency response in the NEM*, August 2017, p. 15.

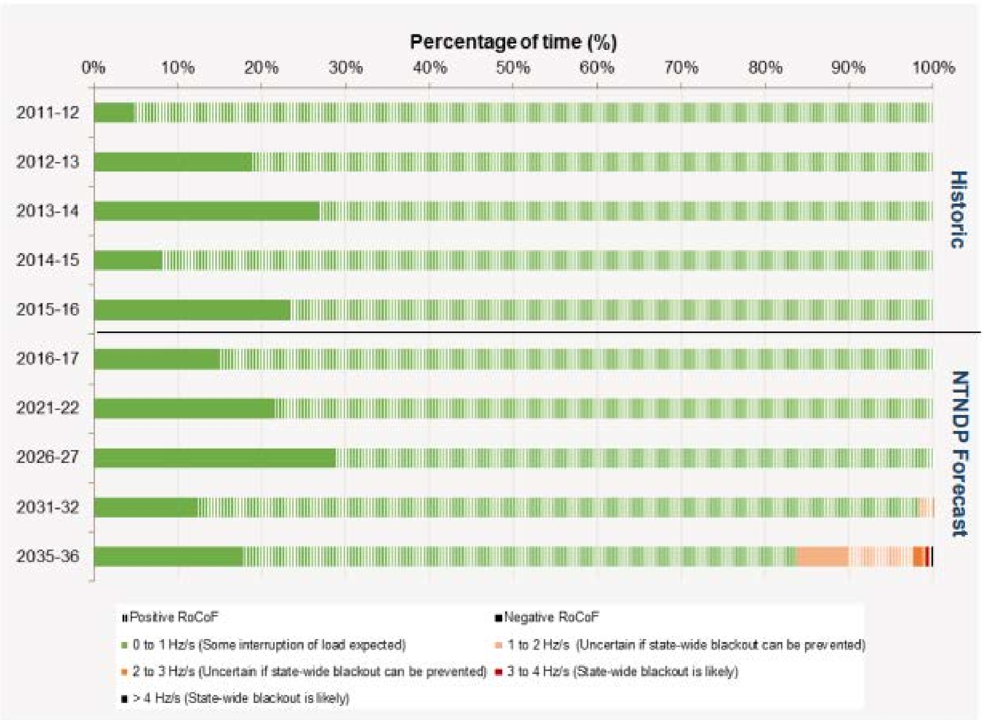
- Generators may not be able to ride through the frequency changes associated with high rate of change of frequency, exacerbating the problem and the amount of under frequency load shedding required.

The potential non-credible loss of the Heywood Interconnector connecting South Australia to Victoria has been identified as an important risk for South Australia. Upon loss of the interconnector, South Australia becomes a synchronous island, and must survive the separation event with local reserves of inertia.

AEMO directly manages flows on the Heywood Interconnector to limit the rate of change of frequency in the event of separation. A special protection scheme (incorporating demand response fast frequency response) has been designed and implemented by ElectraNet, in collaboration with AEMO, to provide a more cost effective long term option for managing this risk.

With projected growth in non-synchronous generation, Queensland may eventually require similar control mechanisms. Figure 5.16 illustrates the rate of change of frequency exposure related to the non-credible loss of the QNI interconnector which connects Queensland to New South Wales. From 2035/36, rate of change of frequency exposure is in the range of 1-2 Hz/s or higher more than 15 per cent of the time, indicating an increasing risk to power system security. A special protection scheme may be appropriate from that time.

Figure 5.16 Rate of change of frequency exposure for the non-credible loss of QNI interconnector (Queensland)



Source: AEMO, *Fast frequency response in the NEM*, August 2017, p. 16.

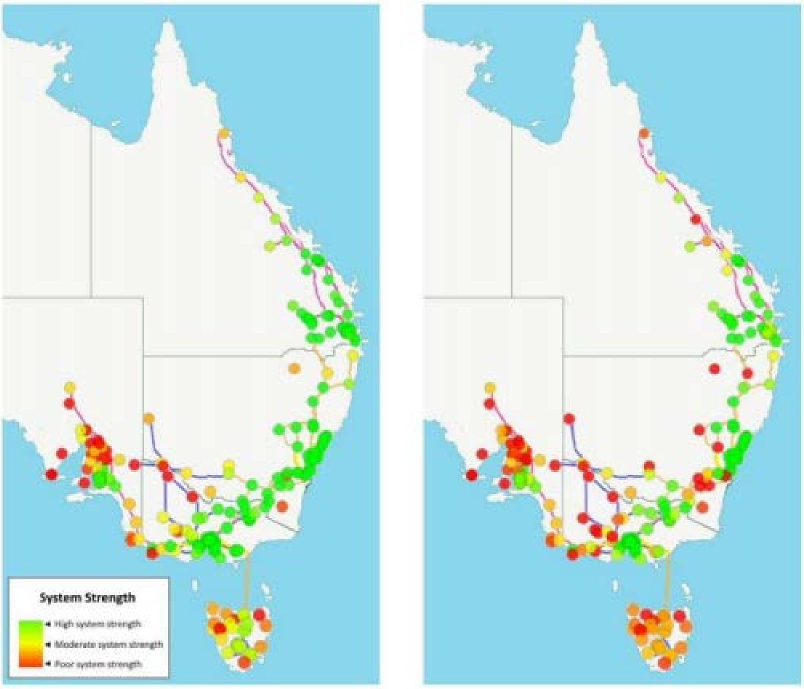
5.3.4 System Strength

System strength is a characteristic of an electrical power system that relates to the size of the change in voltage for a change to the load or generation at a connection point. When the system strength is high at a connection point the voltage changes very little for a change in the loading. However, when the system strength is lower the voltage would vary more with the same change in loading.

System strength is typically provided by synchronous generation. The supportive characteristics of synchronous generation are not typically provided by power electronic converter-connected, non-synchronous generation technologies. The exit of large thermal synchronous generation, together with an increasing proportion of non-synchronous generation like wind and solar, has contributed to decreases in system strength in some areas of the power system.[446]

A projection of estimated future levels of system strength is shown in Figure 5.17. AEMO's assessment, described below, was completed for the 2016 NTNDP. This assessment will be revised based on updated generation projections, as part of the 2018 *Integrated System Plan*. Commentary on the revised assessment will be included as part of the 2018 AMPR.[447]

Figure 5.17 Projected system strength in 2016/17 (left) and 2035/36 (right)



Source: AEMO, *National transmission network development plan*, December 2016, p. 67

AEMO's projection predicts that there may be reduced system strength in Tasmania, South Australia and west Victoria by 2035/36. Additionally, system strength is also projected to decline throughout New South Wales and Queensland as increasing levels of non-synchronous generation look to connect there.[448]

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446 AEMO, *Future power system security program progress report,* August 2016, p. 45.

447 AEMO have indicated that their system strength projections have been accelerated since the 2016 NTNDP assessment, driven by the significant number of connection proposals.

448 AEMO, *National transmission network development plan*, December 2016, p. 67.

Declining system strength can lead to localised issues and can also have broader power system impacts. Three potential challenges for power system security are:[449]

- the possible reduced effectiveness of some types of network and generating systems' protection functions
- power electronic converter-interfaced devices such as wind turbines and solar inverters require a minimum fault level to operate in a stable and reliable condition. Reduced system strength could therefore impact on their ability to ride through faults on the system
- voltage control in response to small and large system disturbances is also affected by system strength, with weaker systems more susceptible to voltage instability or collapse.

In November 2017 AEMO published *Interim system strength impact assessment guidelines*.[450] The guidelines provide an initial description of the principles and methodologies to be used when assessing the impact on the strength of the electrical system of a proposed new or modified generating system or market network service facility connection to the NEM. The guidelines identify potential system strength remediation schemes that include:[451]

- Reduction in the registered capacity of the plant.
- Modifications to control systems forming part of the generating system under consideration.
- Contracting arrangements with other synchronous generators for provision of system strength services.
- Modification to arrangements at or behind the network connection point such as:
  - Use of a higher connection voltage.
  - Use of multiple or lower impedance transformers.
  - Use of lower impedance feeder networks
  - Installation of synchronous condensers
  - Installation of local static synchronous compensators or similar flexible AC transmission system devices.
- Dispatch constraints.

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449 AEMO, *Future power system security program progress report,* August 2016, p. 45

450 AEMO was required to determine the interim system strength impact assessment guidelines, in accordance with clauses 11.101.2 and 4.6.6 of the NER, as amended by the *National Electricity Amendment (Managing power system fault levels) Rule 2017 No. 10*. The final guidelines must be published by 1 July 2018. For more information on the interim guidelines, see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Interim-System-Strength-Impact-Assessment-Guidelines-PUBLISHED.pdf

451 A system strength remediation scheme is a scheme agreed or determined under rules clause 5.3.4B that is required to be implemented as a condition of a connection agreement to remedy or avoid an adverse system strength impact. AEMO, *Interim system strength impact assessment guidelines*, 17 November 2017, p. 14.

- Post contingency control schemes (such as a System Integrity Protection Scheme).[452]

Network Support and Control Ancillary Services (NSCAS) in South Australia

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.

In the 2016 NTNDP, AEMO identified an NSCAS gap to provide system strength in South Australia, and stated that the gap would be confirmed in 2017 following the completion of more detailed analysis. AEMO has since published a report which evaluated the adequacy of system strength in South Australia for various levels of synchronous and non-synchronous generation.[453]

AEMO published an update to the 2016 NTNDP in which it identified that without system strength limitations, there might be periods where no synchronous generators would operate in South Australia.[454] On 13 October 2017, AEMO formally declared a system strength NSCAS gap for 620MVA in South Australia region under clauses 11.101.6 and 11.101.7(c) of the NER, to be provided by synchronous machines within South Australia.[455] Combinations of online synchronous generators are required to maintain sufficient system strength to withstand a credible fault and loss of a synchronous generator.[456] ElectraNet is required to use reasonable endeavours to address this shortfall by 30 March 2018. ElectraNet is currently undertaking an economic evaluation to identify the most cost effective solution(s) to address this ongoing requirement over the short and longer-term.

The Panel notes that since July 2017 there have been a number of directions issued by AEMO in South Australia to maintain the power system in a secure state. The issue of declining system strength has been addressed with the new framework established by the AEMC's *Managing power system fault levels* rule.[457] AEMO intends for the system strength framework to replace the need for similar directions.[458]

System strength constraint in South Australia

In July 2017 AEMO introduced a new system strength constraint in South Australia. The new constraint initially restricted non-synchronous (wind) generation to 1200MW

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452 AEMO notes that if many new asynchronous generator connections have tripping schemes for local N-1 contingencies this will add to the risk profile AEMO manages operationally and this has potential system security and reliability impacts.

453 AEMO, *South Australia System Strength Assessment,* September 2017.

454 AEMO, *Second update to the 2016 National Transmission Network Development Plan,* October 2017, p. 5.

455 Fault current is used as a proxy for the level of inertia, fault current, synchronising torque, and other synchronous characteristics which a power system needs. The NSCAS gap was measured at the Davenport 275 kV transmission connection point. The NSCAS gap is required for the remainder of the current five-year NSCAS planning horizon (until 1 July 2021) and beyond.

456 This is currently the case, however AEMO notes the system strength requirement could be provided through other means (such as synchronous condensers).

457 For further detail on the rule refer to section 5.4.5

458 AEMO, *Second update to the 2016 National Transmission Network Development Plan*, October 2017, p. 5.

when only a minimum system strength requirement was met. In December 2017, AEMO announced this limit had been increased from 1200MW to 1295MW.[459]

Associated costs

The Panel acknowledges that directions issued by AEMO to maintain system security have associated costs including: compensation claims, pricing inefficiencies and sub-optimal dispatch. The Panel notes a further eight direction events occurred between 2 September 2017 and 6 November 2017 with AEMO on all occasions, issuing directions to generators in South Australia to maintain the system in a secure state. The compensation costs associated with these directions have not yet been published.[460] Some of the these directions applied over a period of days, meaning costs associated with pricing inefficiencies and sub-optimal dispatch are likely to be substantial.

The Panel also recognises there are significant costs associated with AEMO's new system strength constraint in South Australia. Restricting output from (non-synchronous) wind generators which traditionally bid into the market at low prices, to allow (synchronous) gas generators with higher marginal costs to remain online during periods of low demand impinges on cost-efficient dispatch of generators.

5.4 Work underway addressing system security

The Panel notes that various projects are currently underway that relate to the security of the power system. A summary of these projects is provided below.

5.4.1 System security market frameworks review

In July 2016, the AEMC self-initiated the *System security market frameworks review* to address two key emerging issues: the management of frequency and of system strength in a power system with reduced levels of synchronous generation.

On 27 June 2017, The AEMC published its final report for the review. The priorities of the review have been to develop recommendations that will result in:[461]

- a stronger system
- a system better equipped to resist frequency changes
- better frequency control
- action to further facilitate the transformation.

Three of the report’s recommendations have been addressed through the *Managing the rate of change of power system frequency* (see section 5.4.4), *Inertia ancillary service market*

459 AEMO, *Transfer limit advice – South Australian system strength*, December 2017, p. 5.

460 The Panel notes that directions issued to generators in South Australia on 25 April 2017 to maintain the system in a secure operating state resulted in payments of $115,783 and $214,568 to participants. For more information see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Market_Event_Reports/2017/0143-2011-AEMO-ANZAC-Direction---Final-Report-290917.pdf

461 For more information on the system security market frameworks review, see the project page: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review#

(see section 5.4.7) and *Managing power system fault levels* (see section 5.4.9) rules. Other recommendations are the subject of the *Generator technical performance standards* rule change (see section 5.4.10), and the *Frequency control frameworks review* (see section 5.4.9).

5.4.2 Review of the system restart standard

On 15 December 2016, the Reliability Panel completed its *Review of the system restart standard* and published a new system restart standard.[462]

The system restart standard specifies the time, level and reliability of generation and transmission capacity to be available for the restoration process following a major supply disruption (or black system event) that results in an uncontrolled power outage in one or more electrical sub-networks in the NEM. As such the system restart standard provides a target for the procurement of system restart ancillary services by AEMO. It is a standard for procurement rather than an operational standard. Operationally, AEMO works in conjunction with generators, network service providers and jurisdictional system security coordinators to restore the power system and customer load as quickly as possible.[463]

The Panel made some changes to the system restart standard in its review. These changes will apply from July 2018. The key changes made to the standard include:

- 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 December 2017 AEMO completed new SRAS guidelines.

The AEMC has recently considered two rule changes addressing SRAS issues. In February 2018 the AEMC published the *System restart plan provisions* rule.[464] In March

462 For more information on the new system restart standard, see the system restart standard review project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-System-Restart-Standard

463 AEMC, *Review of the System Restart Standard: Final determination*, December 2016, p. ii

464 For more information on the *System restart plan release provisions* rule, see the project page: https://www.aemc.gov.au/rule-changes/system-restart-plan-release-provisions.

2018 the AEMC is expected to publish a final rule for the *Testing of system restart ancillary services capability* rule change request.[465]

5.4.3 Emergency frequency control schemes

On 30 March 2017, the AEMC published a final rule for the *Emergency frequency control schemes* rule change request.[466]

The final rule establishes an enhanced framework for emergency frequency control in the National Electricity Market. The final rule includes:

- a framework to regularly review current and emerging power system frequency risks, and then identify and implement the most efficient means of managing emergency frequency events
- an enhanced process to develop emergency frequency control schemes to allow for the efficient use of all available technological solutions to limit the consequences of emergency frequency events, including a formalised arrangement for the management of over-frequency events
- a new classification of contingency event, the protected event, that in the circumstances defined by such an event, will allow power system security to be managed by using a combination of ex-ante solutions, as well as some limited generation or load shedding.

This integrated framework for emergency frequency control schemes and protected events will support security of supply for consumers. However, it is important these measures are delivered efficiently, so that costs for consumers are as low as possible. The final rule sets out clear governance arrangements for both, including a robust cost benefit process, to achieve this outcome.

The rule commenced 6 April 2017.

5.4.4 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 Transmission Network Service Providers (TNSPs) to procure minimum required levels of inertia or alternative frequency control services to meet these minimum levels.[467]

The Commission 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 National Electricity Market while minimising the cost to consumers.

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465 For more information on the *Testing of System Restart Ancillary Services capability rule*, see the project page: https://www.aemc.gov.au/rule-changes/testing-of-system-restart-ancillary-services-capab.

466 For more information on the Emergency frequency control scheme, see the project page: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen#

467 For more information of the *Managing the rate of change of power system frequency rule*, see the project page: http://www.aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque#

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 Australian Energy Regulator to assess the efficiency of that expenditure.
- 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.

The rule commences 1 July 2018.

5.4.5 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.[468]

The key features of the final rule are as follows:

- AEMO to develop a system strength requirements procedure from which it can determine the required fault level at key locations in each transmission network necessary for the power system to be maintained in a secure operating state.
- Where a system strength shortfall exists, an obligation on TNSPs to procure system strength services needed to provide the fault levels determined by AEMO; services are then enabled by AEMO as needed.
- AEMO to develop system strength impact assessment guidelines that set out a methodology to be used by network service providers and generators when assessing the impact of a new generator connection on system strength.[469]
- A requirement on new connecting generators to 'do no harm' to the security of the power system, in relation to any adverse impact on the ability to maintain system stability or on a nearby generating system to maintain stable operation.

The rule commences 1 July 2018.

5.4.6 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.[470] By allowing AEMO and

468 For more information on the *Managing power system fault levels rule*, see the project page: http://www.aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels

469 Consistent with this rules requirement AEMO published *Interim system strength impact assessment guidelines* on 17 November 2017.

470 For more information on the *Generating system model guidelines*. see the project page: http://www.aemc.gov.au/Rule-Changes/Generating-System-Model-Guidelines#

network service providers to access accurate model data, the final rule will support parties in fulfilling their obligations for maintaining system strength.

The final rule amends 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 commences 1 July 2018.

5.4.7 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.[471]

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 underway by the Commission and AEMO, the Commission is not satisfied that the introduction of a market mechanism for inertia is appropriate at this time.

The Commission intends to continue its assessment of the appropriate design of an inertia market mechanism through the recently initiated *Frequency control frameworks review*.

5.4.8 Review of frequency operating standard

The Panel's *Review of the frequency operating standard* has been split into two stages.[472] Stage one is now complete. Stage one addressed primarily technical issues and market framework changes stemming from the new *Emergency frequency control schemes* rule, including the new category of protected contingency event in the frequency operating standard. Stage two will include a broader consideration of the settings of the frequency operating standard and will commence when the AEMC's *Frequency control frameworks review* is further progressed.

At the conclusion of stage one, the Panel made a new frequency operating standard, effective 14 November 2017. The changes for this new frequency operating standard include:

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471 For more information on the *Ancillary service market rule* change, see the project page: http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market

472 For more information on the *Frequency operating standard*, see the project page http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard#

- implementation of changes already made to the rules, through the *Emergency frequency control schemes* rule.
- clarification and further guidance as to how AEMO operates the power system, particularly as this relates to managing different kinds of contingency events.

Specifically, the Panel has made these changes to the frequency operating standard following stage one of the review:

- inclusion of a standard for protected events
- a revised requirement relating to multiple contingency events
- a revised definition of 'generation event'
- revised definitions in the frequency operating standard relating to island operation
- a revised limit for accumulated time error in the mainland

5.4.9 Frequency control frameworks review

On 19 December 2017 the AEMC published a progress update on the frequency control frameworks review.[473] The review is progressing a number of recommendations made by the AEMC in the *System security market frameworks review* and the *Distribution market model* project. The review is considering the following issues:

- **Primary frequency control:** an assessment of the materiality of the degradation of frequency performance under normal operating conditions, what options are available to mitigate the risks of this and the costs/benefits of those options.
- **FCAS:** an exploration of the rationale for the existing frequency control ancillary services that currently exist, whether these will remain relevant in light of the changing generation mix, how fast frequency response services might be incorporated, and long term options to facilitate co-optimisation between frequency control ancillary services and inertia.
- **Distributed energy resources:** an exploration of the regulatory, technical and commercial opportunities and challenges associated with distributed energy resources providing system security services.

The review will seek to identify and develop the changes to market and regulatory arrangements required to address the frequency issues highlighted by AEMO. The review is informed by recommendations from the Finkel Panel's *Independent review into the future security of the national electricity market*. The AEMC is due to publish a draft report on the review in March 2018.

473 For more information on the *Frequency control frameworks review*, see the project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review#

5.4.10 Generator technical performance standards

On 19 September 2017, the AEMC published a consultation paper for the *Generator technical performance standards* rule change.[474] AEMO (the rule proponent) considers that the current access standard settings in the rules and the negotiating framework to set performance standards are not adequate to ensure the ongoing security of an evolving power system. AEMO also considers that the security of the power system may be affected if the connection applications currently before them, as well as those applications expected to be made in the near future, are processed on the basis of the current access standards and negotiating framework. To address these issues, AEMO proposes:

- amending or introducing a number of access standards for connecting generators, including those relating to voltage control and reactive power provision, disturbance ride through, system strength, active power control and remote monitoring and control
- amending the process for negotiating performance standards, and
- implementing transitional arrangements applying the changes to any performance standards agreed on or after 11 August 2017.

The AEMC is due to publish a draft determination on the rule change by 10 April 2018.

5.4.11 Reviews of the black system event in South Australia on 28 September 2016

On 28 March 2017, AEMO published its fourth and final incident report for the South Australian black system event that occurred on 28 September 2016.[475] The final report outlines 19 recommendations aimed at collectively mitigating the risk of similar major supply disruptions occurring in South Australia and the rest of the National Electricity Market. The recommendations aimed to:

- Reduce the risk of islanding of the South Australian region.
- Increase the likelihood that, in the event of islanding, a stable electrical island can be sustained at least in part of South Australia.
- Improve the performance of the system restart process.
- Improve market and system operation processes required during periods of market suspension.

The AER has powers to monitor compliance with, and investigate possible breaches of, the national electricity law and the rules. The AER has commenced its examination of participant compliance and system operation both during and in the lead up to the

474 For more information on the G*enerator technical performance standards rule*, see the project page: http://www.aemc.gov.au/getattachment/7a79a934-f607-43f7-bd73-acbb8d3739a3/Information-sheet.aspx

475 AEMO, *Black System South Australia 28 September 2016, Final Report*, March 2017

black system event, and in the subsequent period of market suspension.[476] The areas of focus for the AER investigation include (but are not limited to):

- **Pre-event:** the actions AEMO and ElectraNet leading up to the event, including the adequacy of existing processes and procedures for undertaking assessments of the risk to equipment and/or power system security.
- **Event:** whether equipment, including that of relevant wind farms, complied with performance standards required under the rules.
- **System restoration:** the arrangements in place to facilitate system restoration after a black system event, including the causes of issues experienced by system restart ancillary service providers and participants' compliance with AEMO instructions during the restoration period.
- **Market suspension:** given that the duration of the market suspension was longer than was contemplated during the design stage of the suspension arrangements, the AER is looking closely at this area and its impacts.

The Panel understands the AER will complete its compliance review in 2018.

The COAG Energy Council has requested that the AEMC conduct a review that will build on the work undertaken by AEMO and the AER by identifying any systemic issues that contributed to the event or affected the response. The Commission is to provide a report to Ministers on:

- any recommended actions or amendments to the regulatory frameworks that should be taken to address any systemic issues identified
- the extent to which the recommendations will be addressed in the AEMC's ongoing work program.

The final report to the Council is due six months after the finalisation of both AEMO's investigation report and the AER's compliance report.

476 AER, *Quarterly Compliance Report: National Electricity and Gas Laws*, July - September 2016, p. 2.

6 Safety review

This chapter presents the Panel's review of the power system from a safety perspective for 2016/17.

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. 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.

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 G.

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 2016/17. 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.[477]

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.[478] The Panel notes that there were no instances in 2016/17 where this occurred.

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477 This is an agenda item at the meetings of the Power System Security Working Group. This group consists of TNSP control room managers and AEMO control room managers. No issues have been raised by working group representatives in relation to this agenda item for 2016/17.

478 Directions issued to maintain the power system in a secure operating state are discussed in section 5.1.7

A Generation capacity changes

This appendix summarises changes in generation capacity in the NEM during 2016/17. Generally, the changes included:

- an increase in renewable sources of generation, namely more wind farms and large-scale solar
- large withdrawals of synchronous generation from Victoria and Tasmania, and announced withdrawals of synchronous generation from Queensland and New South Wales

A.1 Increases in NEM capacity

Table A.1 provides a granular analysis of the generation capacity committed and commissioned during 2016/17. Almost all of the generation commissioned or committed in 2016/17 comes from renewable resources.[479] In 2016/17 441MW of generation was commissioned and 1312MW of generation was committed across Queensland, New South Wales, Victoria and South Australia.[480]

Table A.1 New generation commissioned and committed in 2016/17

Region	Status (at the end of 2016/17)	Power station	Capacity (MW)	Fuel source
Queensland[481]	Commissioned	Grosvenor 1	21	Waste coal mine gas
	Commissioned	Barcaldine Remote Community Solar Farm	20	Solar
	Commissioned	Oaky Creek 2	15	Waste coal mine gas
	Committed	Mt Emerald	181	Wind
	Committed	Clare Solar Farm	100	Solar

479 The two non-renewable generators commissioned in this period were in Queensland, being two waste coal mine gas units (Grosvenor 1, 21MW and Oaky Creek 2, 15MW).

480 Since the end of the 2016/17 reporting period almost 3GW of new generation projects have been committed. This includes expansions and upgrades to existing generation as well as the fully operational Hornsdale Power Reserve Unit (100MW battery) in South Australia.

481 New generation projects committed in Queensland since the end of the 2016/17 reporting period include: Collinsvile Solar Power Station (43MW), Coopers Gap Wind Farm (453MW), Darling Downs Solar Farm (110MW), Daydream Solar Farm (168MW), Dunblane Solar Farm (7MW), Hayman Solar Farm (58MW), Kennedy Energy Park (Solar 15MW, Wind 43MW, Storage 2MW), Kidston Solar Project (50MW), Lake Somerset (4MW), Lakeland Solar and Storage Project (13MW), Lilyvale Solar Farm (15MW), Longreach Solar Farm (15MW), Oakey 1 Solar Farm (25MW), Ross River Solar Farm (116MW), Rugby Run Solar Farm (65MW), Sun Metals Solar Farm (125MW), Sunshine Coast Solar Farm (15MW) and Tableland Mill (24MW).

Region	Status (at the end of 2016/17)	Power station	Capacity (MW)	Fuel source
	Committed	Hamilton Solar Farm	58	Solar
	Committed	Whitsunday Solar Farm	58	Solar
New South Wales[482]	Commissioned	Mugga Lane Solar Farm	13	Solar
	Commissioned	Williamsdale Solar Farm	10	Solar
	Committed	White Rock Wind Farm	173	Wind
	Committed	Parkes Solar Farm	55	Solar
	Committed	Manildra PV Solar Farm	50	Solar
	Committed	Griffith Solar Farm	30	Solar
Victoria[483]	Commissioned	Ararat Wind Farm	240	Wind
	Committed	Mt Gellibrand	66	Wind
	Committed	Gannawarra Solar Farm	50	Solar
	Committed	Kiata Wind Farm	31	Wind
	Committed	Yaloak South	29	Wind
South	Commissioned	Hornsdale Wind Farm Stage 1	102	Wind

482 New generation projects committed in New South Wales since the end of the 2016/17 reporting period include: Bodangora Wind Farm (113MW), Silverton Wind Farm (199MW), White Rock Solar Farm (20MW), Sapphire Wind Farm Phase 1 and 2 (270MW); Hunter Economic Zone Diesel (29MW), Crookwell 2 Wind Farm (91MW). Bayswater Power Station will increase capacity by 25MW each winter from 2019 to 2022.

483 New generation projects committed in Victoria since the end of the 2016/17 reporting period include: Bannerton Solar Park (88MW), Gannawarra Solar Farm (50MW), Crowlands Wind Farm (80MW), Swan Hill Solar Farm (15MW) and Yatpool Solar Farm (81MW). Loy Yang B is to be upgraded with an additional 78MW of capacity, with total capacity for the power station to 1078MW. Generation capacity of Mt Gellibrand to be expanded by 66MW, to take total capacity to 132MW.

Region	Status (at the end of 2016/17)	Power station	Capacity (MW)	Fuel source
Australia[484]	Commissioned	Waterloo Wind Farm	20[485]	Wind
	Committed	Hornsdale Wind Farm Stage 2	102	Wind
	Committed	Hornsdale Wind Farm Stage 3	109	Wind
	Committed	Bungala One	110	Solar
	Committed	Bungala Two	110	Solar
Total commissioned			**441**	
Total committed			**1312**	

Source: AEMO, *Generator Information page*, 5 June 2017 and 29 December 2017.

A.2 Withdrawn generation

In 2016/17, all the generation withdrawn was synchronous and was from Victoria and Tasmania. Table A.2 lists the withdrawn generation and generation that has announced the intention to withdraw.

Table A.2 Generator withdrawals during 2016/17

Region	Status (at the end of 2016/17)	Power station	Capacity (MW)	Fuel source
Queensland	To be withdrawn	Mackay GT Power Station	34	Gas
	To be withdrawn	Daandine Power Station	30	Gas
New South Wales	To be withdrawn	Liddell A Power Station	2000	Black coal
Victoria	Withdrawn	Hazelwood Power Station	1600	Brown coal
South Australia	No generation withdrawn or announced for withdrawal in 2016/17			
Tasmania	Withdrawn[486]	Tamar Valley CCGT	208	Gas

484 New generation projects committed in South Australia since the end of the 2016/17 reporting period include: Lincoln Gap Wind Farm Stage 1 (126MW) and Willogoleche Wind Farm (119MW). The Hornsdale Power Reserve Unit 1 (100MW, 129MWh) is now operational.

485 Extension to existing wind farm. Total wind farm capacity is 131MW

486 Tamar Valley CCGT returned to service for summer 2017/18. Hydro Tasmania advises that Tamar Valley will be withdrawn again after April 2018.

Source: AEMO, *Generator Information page*, 5 June 2017 and 29 December 2017.

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 - already recalled for summer 2017/18
	Callide A	30	No
Victoria	Hazelwood Power Station	1600	No
Tasmania	Tamar Valley CCGT	208	Yes - available for operation with less than three months notice[487]

Source: AEMO, *Generator Information page*, 5 June 2017 and 29 December 2017.

487 Refer to previous footnote. After Tamar Valley CCGT has been withdrawn again in April 2018, it can return to service within three months

B Network performance

This appendix provides a summary of transmission network and distribution network performance in 2016/17.

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.

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.

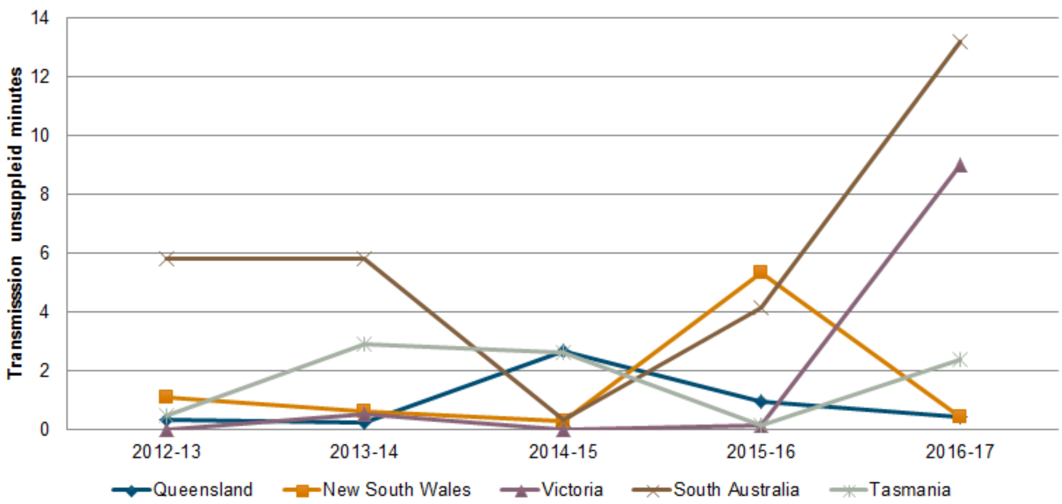
B.1 Transmission network

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[488]



Source: Queensland - Powerlink; New South Wales - TransGrid; Victoria - AusNet Services; South Australia - ElectraNet; Tasmania - TasNetworks.

In 2016/17, both Queensland and New South Wales experienced decreased levels of transmission unsupplied minutes. Victoria, South Australia and Tasmania experienced a significant increase in transmission unsupplied minutes from 2015/16 levels.

488 The calculated value of unsupplied minutes is the amount of energy not supplied, divided by maximum demand, multiplied by 60. 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.

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.[489]

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.[490]
- 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.[491]

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 Transmission Network Design and Reliability Standard dated December 2010.

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489 The service target performance incentive scheme is developed and published by the AER in accordance with clause 6A.7.4 of the rules.

490 Section 34(2) of the *Electricity Act 1994 (Queensland)*.

491 Transmission Authority No. T01/98.

In general terms the standard requires TransGrid to plan and develop its transmission network on an "N–1" basis. This may be varied to accommodate AEMO's operating practices, distributor licence conditions or by agreement with distributors or other customers.

The standard requires that TransGrid's planning process be interlinked with licence obligations placed on distributors in New South Wales. In particular, TransGrid must ensure that their transmission network is adequately planned to enable distributor licence requirements to be met. TransGrid outlines its plans to meet its obligations with the standard in the transmission annual planning report that it publishes by 30 June each year.

B.1.4 Victoria

AEMO is responsible for planning and directing augmentations of the Victorian electricity declared shared network in accordance with its obligations under the rules. AEMO identifies the benefits of various network and non-network investment options.

These benefits may, amongst other things, result from:

- a reduction in unserved energy
- a reduction in generation fuel costs
- transmission loss reductions
- capital plant deferrals.

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 has commenced a review of the specific reliability standards set out in clause 2 of the Electricity Transmission Code. The final determination, which was published in September 2016, resulted in no material changes to reliability standards and will be reflected in ElectraNet's revenue proposal for the 2018/2023 regulatory control period.[492]

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

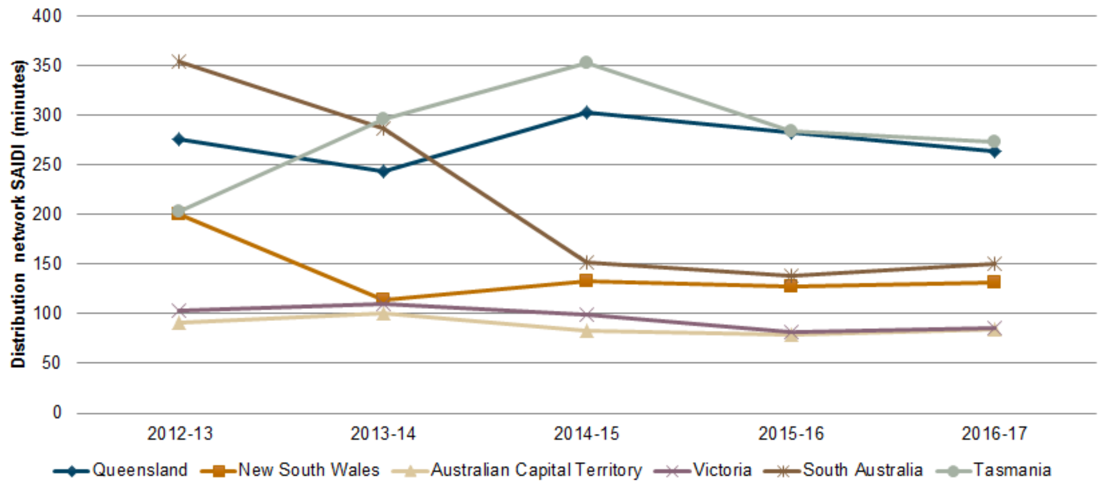
The performance of distribution networks, and the reliability standards that must be met, fall within the responsibility of jurisdictions.

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

492 ESCOSA, Electricity Transmission Code review: Final decision, September 2016.

Figure B.2 Distribution network SAIDIs



Source: Queensland - Queensland Department of Energy and Water Supply; 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 2016/17 with the exception of South Australia, all jurisdictions experienced flat or declining levels of distribution outages. 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).[493]

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.

Prior to 1 July 2014, minimum service standards reporting requirements were included in the Queensland Electricity Industry Code and reports were published on the Queensland Competition Authority (QCA) website. From 1 July 2014, all minimum service standards provisions (including requirement for QCA to review minimum service standards arrangements in the future) were removed from the Electricity Industry Code. However, the Minister proposed that the QCA may be directed, under section *120L of the Electricity Act 1994*, to conduct a review of the minimum service standards where required. From 1 July 2014, minimum service standards reporting requirements were incorporated as conditions of the distribution authorities and reports are published on the Business Queensland website.

Minimum service standards (reliability limit targets) for the 2016/17 financial year are outlined in Schedule 2 of the respective distribution authorities. The Electricity Industry Code was replaced by the Electricity Distribution Network Code from 1 July 2015 (made under the Electricity Act 1994). The Electricity Distribution Network Code sets guaranteed service levels and payments that must be met by Energex and Ergon Energy. Ergon Energy and Energex report quarterly to the QCA on their guaranteed

493 As of June 2016 Ergon Energy and Energex merged to form Energy Queensland.

service levels performance relative to their targets. The QCA then reports this information to the Department of Energy and Water Supply.[494]

Table B.1 details the performance of Energex and Ergon Energy against the minimum service standards set for 2016/17. It shows that Energex and Ergon met all of their SAIDI and SAIFI targets for the different feeder categories during 2016/17.

Table B.1 Performance of Queensland DNSPs in 2016/17

DNSP	Feeder level	SAIDI		SAIFI	
		Target	Average	Target	Average
Energex	CBD	15	3.84	0.150	0.024
	Urban	106	76.26	1.260	0.671
	Short-rural	218	164.64	2.460	1.453
Ergon	CBD	149	106.99	1.980	1.135
	Short-rural	424	279.38	3.950	2.637
	Long-rural	964	954.72	7.400	5.804
Average	-	-	264	-	-

Source: Queensland Department of Energy and Water Supply.

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.[495]

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
- network immediate and 24 hour reports of major network incidents
- annual compliance audits
- consumer complaints, including to the New South Wales Energy and Water Ombudsman

494 The Department of Energy and Water Supply was recently combined with the Department of Natural Resources and Mines to create the new Department of Natural Resources, Mines and Energy.

495 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

- media reports.

The network operators in New South Wales are required by the *Electricity Supply (Safety and Network Management) Regulation 2008* to publish annual reports on network performance against their electricity network safety management systems, and for the licensed operators this includes a section on reliability. 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 2016/17.[496]

Table B.2 Performance of New South Wales DNSPs in 2016/17

DNSP	Feeder level	SAIDI		SAIFI	
		Target	Actual	Target	Actual
Essential Energy	Urban	125	75.0	1.8	0.9
	Short-rural	300	225.0	3	1.9
	Long-rural	700	494.0	4.5	3.2
	All	n/a	236.0	n/a	1.9
Ausgrid	CBD	45	15.8	0.3	0.04
	Urban	80	72.8	1.2	0.6
	Short-rural	300	119.0	3.2	1.2
	Long-rural	700	838.2	6	3.9
	All	n/a	79.0	n/a	0.7
Endeavour Energy	Urban	80	57.8	1.2	0.7
	Short-rural	300	182.3	2.8	1.6
	Long-rural	n/a	1761.5	n/a	10.7
	All	n/a	78.4	n/a	0.9
Average	-	-	131.13	-	-

Source: IPART

496 More detailed performance information is available from network performance reports published on each of the DNSPs websites.

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 2016/17. It shows that ActewAGL met its SAIFI and SAIDI targets for rural short feeders and exceeded its targets for urban feeders.[497]

Table B.3 Performance of ActewAGL for 2016/17

Feeder level		SAIDI		SAIFI		CAIDI[498]	
		Target	Actual	Target	Actual	Target	Actual
Urban	Overall	n/a	83.91	n/a	0.883	n/a	95
	Distribution network - planned	n/a	44.80	n/a	0.215	n/a	208.6
	Distribution network - unplanned	n/a	68.90	n/a	0.845	n/a	81.6
	Normalised distribution network - unplanned	30.32	39.11	0.585	0.669	n/a	58.5
Rural short	Overall	n/a	82.44	n/a	1.042	n/a	79.1
	Distribution network - planned	n/a	39.70	n/a	0.19	n/a	209.1
	Distribution network -	n/a	75.30	n/a	0.977	n/a	77.1

497 More detailed performance information is available from network performance reports published on ActewAGL's website, http://www.actewagl.com.au/Networks.aspx

498 Customer average interruption duration index

Feeder level		SAIDI		SAIFI		CAIDI[498]	
		Target	Actual	Target	Actual	Target	Actual
	unplanned						
	Normalised distribution network - unplanned	46.86	42.74	0.895	0.852	n/a	50.2
Network	Overall	n/a	83.86	n/a	0.903	n/a	92.9
	Distribution network - planned	n/a	44.32	n/a	0.213	n/a	208.2
	Distribution network - unplanned	n/a	69.63	n/a	0.86	n/a	81.0
	Normalised distribution network - unplanned	n/a	39.53	n/a	0.69	n/a	57.3

Source: ActewAGL Distribution

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.[499] These targets are developed for the purpose of applying the AER's service target performance incentive scheme to the DNSPs. Under the service target performance incentive scheme,

499 The AER released its distribution revenue and service determination for the 2016-20 period in May 2016.

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 2016/17. Every Victorian DNSP met some but not all of its SAIDI and SAIFI targets.

Table B.4 Performance of Victorian DNSPs for 2016/17

DNSP	Feeder level	SAIDI		SAIFI	
		Target	Actual	Target	Actual
Jenema	Urban	55.40	41.56	0.95	0.83
	Short-rural	91.95	119.93	1.24	1.82
	Whole network	n/a	45.60	n/a	0.88
CitiPower	CBD	9.13	9.31	0.13	0.13
	Urban	32.70	27.82	0.48	0.41
	Whole network	n/a	24.50	n/a	0.36
Powercor	Urban	83.11	86.57	1.05	1.07
	Short-rural	113.19	97.67	1.36	1.10
	Long-rural	273.09	235.03	2.37	1.98
	Whole network	n/a	129.66	n/a	1.32
AusNet Services	Urban	81.54	83.74	1.10	0.86
	Short-rural	188.05	217.82	2.29	2.16
	Long-rural	233.98	297.37	2.83	2.80
	Whole network	n/a	171.37	n/a	1.69
United Energy	Urban	61.19	46.52	0.90	0.69
	Short-rural	151.60	156.44	2.02	2.26
	Whole network	n/a	54.45	n/a	0.80
Average			85.11		1.01

Source: AER

B.2.6 South Australia

The Essential Services Commission of South Australia (ESCOSA) continues to be responsible for setting elements of the service standard framework. For example, ESCOSA remains 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 seven geographic regions 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.[500]

Table B.5 shows a summary of the performance of SA Power Networks for 2016/17 against the performance targets pertaining to each feeder classification. SA Power Networks met almost all of its performance targets in 2016/17.

Table B.5 Performance of SA Power Networks for 2016/17

Feeder level	SAIDI		SAIFI	
	Target	Actual	Target	Actual
CBD	15	16	0.15	0.11
Urban	120	111	1.30	1.12
Short-rural	220	230	1.85	1.71
Long-rural	300	264	1.95	1.43
Total network	165	151	1.50	1.24

Source: ESCOSA

500 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 current scheme is available at http://www.escosa.sa.gov.au/projects-and-publications/projects/electricity/sa-power-networksservice

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 2016/17, against the performance targets pertaining to each community category. In 2016/17, the high density commercial category was the only category where performance was within both the frequency and duration limits. Duration limits were also met for critical infrastructure; duration limits were exceeded for the other three community categories. All of the outage frequency limits were met with the exception of the critical infrastructure target.

Table B.6 Performance of TasNetworks (distribution) for 2016/17

Community category	SAIDI		SAIFI	
	Target[501]	Actual	Target	Actual
Critical infrastructure	30	27	0.2	0.35
High density commercial	60	12	1	0.14
Urban and regional centres	120	140	2	1.14
Higher density rural	480	530	4	3.01
Lower density rural	600	659	6	3.49

Source: TasNetworks

501 These targets are set as 12 month limits in the Tasmanian Electricity Code.

C Reliability assessment

This appendix provides details on the information sources used to assess reliability in the NEM

C.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 replaces the *National electricity forecasting report*)
- the *Electricity statement of opportunities* (ESOO)
- the *Integrated system plan* (which now incorporates the *National transmission network development plan*)
- the *Energy supply outlook* (which now incorporates the *Energy adequacy assessment projection*)
- 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.

C.1.1 Electricity forecasting insights

AEMO published the first EFI in June 2017. The EFI provides forecasts of electricity consumption and maximum and minimum demand forecasts over a 20-year outlook period (to 2036-37) for the NEM. The EFI takes the place of AEMO's *National electricity forecasting report* that was published annually in June.

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 2017 ESOO updated the demand forecasts provided in the 2017 EFI following:[502]

- a review of how energy prices may impact energy demand, and how this can be best accounted for in modelling methods
- the findings of interviews with large industrial consumers in each region that were conducted to update price response assumptions
- a recalibration of annual consumption forecasts, to have the starting point reflect actual demand levels observed in 2016–17.

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502 AEMO, *ESOO*, September 2017, p. 12.

C.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.

C.1.3 Energy supply outlook

AEMO published its first *Energy supply outlook* in June 2017. It provided an integrated assessment of gas and electricity supply adequacy for eastern and south-eastern Australia over the next two years. The *2017 Energy supply outlook* updated the findings of the 2016 ESOO and the March 2017 *Gas statement of opportunities* and also included the *Energy adequacy assessment projection*.

AEMO notes that given the current dynamic environment, it intends to release more frequent energy supply outlook updates.[503]

C.2 Planning information

C.2.1 Integrated system plan

AEMO is preparing an inaugural ISP for the NEM for publication in June 2018. The ISP was recommended by the Finkel Panel's *Independent Review into the Future Security of the NEM*.

The ISP will consider a wide spectrum of interconnected infrastructure and energy developments including transmission, generation, gas pipelines, and distributed energy resources. Updates to the June 2018 ISP are expected in future years to reflect the changing nature of the power system and the need to continually innovate and evolve strategies for the future.[504]

The first ISP will deliver a strategic infrastructure development plan, based on sound engineering and economics, which can facilitate an orderly energy system transition under a range of scenarios. This ISP will particularly consider:

- the criteria for a successful renewable energy zone
- the way successful renewable energy should be developed
- transmission development options.

AEMO published a consultation paper on the ISP in December 2017.

503 AEMO, *Energy supply outlook*, June 2017, p. 2.

504 AEMO, *Integrated system plan*, December 2017, p. 3.

D Forecasts

This appendix considers various market forecasts of demand and generation reported by AEMO in 2016/17.

The Panel has previously noted 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 EFI and ISP reports have been discussed in chapter 3 and appendix C. The key findings from AEMO’s ESOO and GSOO publications are described in chapter 4.

D.1 Regional forecast accuracy - operational consumption and maximum demand

AEMO's *Forecast accuracy report* assesses the accuracy of the annual operational consumption and maximum operational demand forecasts in AEMO's *2016 National Electricity Forecasting Report* for each NEM region.[505]

The key drivers for each region are:[506]

- **Queensland:** actual operational consumption was 0.6 per cent below forecast. This was due to a slower than expected ramp up of LNG projects which was partly offset by actual consumption in other sectors being higher than forecast, with warmer weather driving up the need for cooling.
- **New South Wales:** actual operational consumption was 0.5 per cent higher than forecast. This was driven by the significantly warmer weather which resulted in more cooling degree days.
- **Victoria:** actual operational consumption was 4.9 per cent below forecast. This was due to the outage of the Portland smelter in December 2016 that forced it to operate at reduced capacity for the remainder of the financial year.
- **South Australia:** actual operational consumption was 0.6 per cent below forecast. The 28 September 2016 black system event was a contributing factor.
- **Tasmania:** actual operational consumption was 2.8 per cent below forecast. Industrial consumption was lower than forecast. It was also a significantly warmer year, resulting in heating requirements being down by 34 per cent..

505 The Panel's reporting of annual operational consumption is on an "as generated" basis.

506 AEMO, *Forecasting accuracy report 2017*, November 2017, pp. 7-11.

The regional differences between forecast operational consumption and actual operational consumption ranged from -4.9 per cent to 0.5 per cent. The forecast and actual operational consumption values are presented in Table D.1.

Table D.1 Difference between forecast and actual operational consumption

Region	Forecasted operational consumption (GWh)	Actual operational consumption (GWh)	Difference (GWh)	Difference (per cent)
Queensland	55,477	55,160	-317	-0.6%
New South Wales	70,977	71,367	390	0.5%
Victoria	47,454	45,232	-2,222	-4.9%
South Australia	12,765	12,688	-77	-0.6%
Tasmania	10,409	10,126	-283	-2.8%
NEM	197,082	194,573	-2,509	-1.29%

Source: AEMO, *Forecast Accuracy Report 2017*, November 2017

The regional differences between forecast and actual maximum demand ranged from -6.4 per cent to 3.8 per cent. The forecast maximum demand and actual maximum demand values are presented in Table D.2.

Table D.2 Difference between forecast and actual maximum demand

Region	Forecast maximum demand (MW)[507]	Actual maximum demand (MW)	Difference (per cent)
Queensland	8,633	8,930	3.3
New South Wales[508]	14,151	13,670	-3.5
Victoria	7,918	8,230	3.8
South Australia	3,081	3,017	-2.1
Tasmania	1,785	1,678	-6.4

Source: AEMO, *Forecast Accuracy Report 2017*, November 2017

507 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 New South Wales, South Australia and Tasmania this is the 10 per cent POE forecast, for Queensland and Victoria this is the 90 per cent POE forecast.

508 Actual maximum demand for New South Wales occurred on 10 February 2017. On this day, actual maximum demand may have been higher if it had not been for a general call for reduced consumption (a reduction of approximately 200 MW below expected was observed at the time of peak demand, which may have been due to a customer response) and the Tomago smelter's output being reduced.

Improvements to the forecasting process

AEMO has made minor updates to the 2017 demand forecasting framework to capture changes, such as:[509]

- Updating PV and battery storage forecasts to account for lower prices during the "solar trough" – the period in the middle of the day when supply from rooftop and utility scale PV systems will meet an increasing share of the customer demand, causing wholesale prices to fall. This "trough" will:
  - Lower the incentives for installing additional PV, as supply during times when PV is generating is generally cheaper compared to other times of the day
  - Increase the value of combined PV and battery installations, as the owner can choose to use the power when supply from the grid would be more expensive.
- Adopting the electricity consumption forecasts for electric vehicles that were presented in an AEMO Insights paper in August 2016.[510]
- Undertaking climate change normalisation of historical weather input data and long-range climate forecasts, based on advice from CSIRO and Bureau of Meteorology.

Concurrently with the 2017 improvements, AEMO has been developing a forecasting insights analytics platform. This will be used for the 2018 forecasts. This system will:

- allow for more regular updates to forecasts
- track the impact on overall forecasts that arises from changes in individual forecasting components.

D.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-hourly basis.

Pre-dispatch provides an aggregate supply and demand balance comparison for each half-hour from the current trading interval up to 36 hours ahead. This information is provided to the relevant participants to assist with their operations management.

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 timeframes. 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

509 AEMO, *Forecast Accuracy Report 2017*, November 2017, p. 12.

510 For more information see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/AEMO-insights_EV_24-Aug.pdf

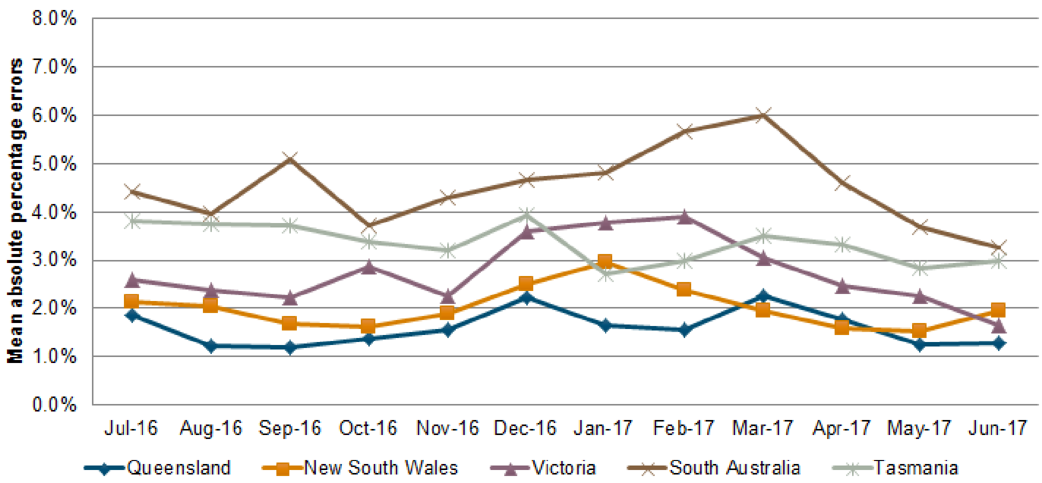
levels for pre-dispatch and ST-PASA periods.[511] Operational decisions are made based on the reserves calculated using 50 per cent POE forecasts.

The key inputs into the demand forecasting system include:

1. historical actual load data (supervisory control and data acquisition (SCADA) data)
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. type of day, school holidays, public holidays and daylight savings information
7. mandatory restrictions (MR)/RERT schedules when relevant.

Figure D.1 shows the mean absolute percentage error for load forecasting 12 hours ahead.

Figure D.1 Load forecasting error - 12 hours ahead[512]



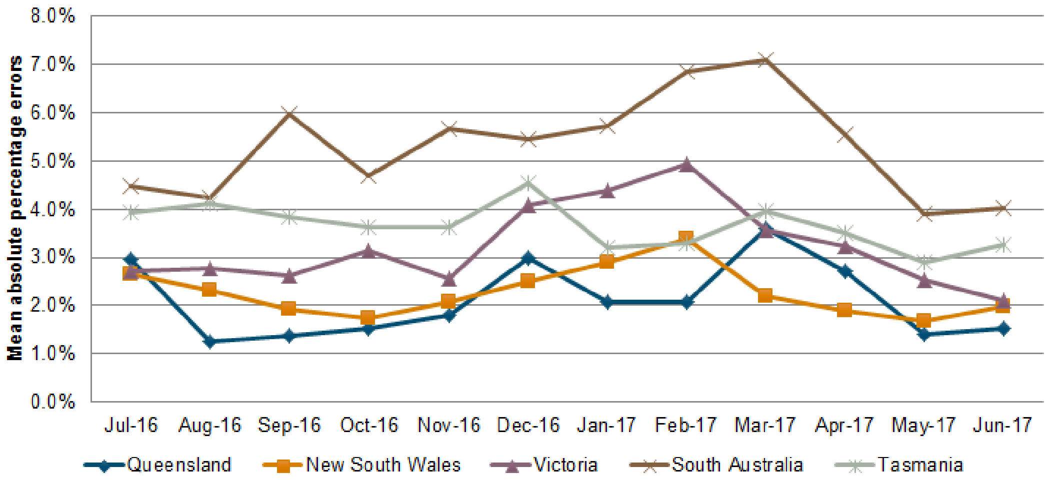
Source: AEMO

Figure D.2 shows the mean absolute percentage error for load forecasting two days ahead

511 AEMO, *Power system operating procedure - load forecasting*, June 2014.

512 South Australian black system event (28/9/2016 16:18 - 11/10/2016 22:30) has been excluded from the mean absolute percentage error forecasting analysis

Figure D.2 Load forecasting error - two days ahead[513]



Source: AEMO

In regards to load forecasting in 2016/17, 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.

D.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 the PASA availability of each scheduled generating unit, scheduled load or scheduled network service for each day taking into account the ambient weather conditions forecast at the time of the 10 per cent POE peak load for the next 24 months. They should also submit weekly energy constraints applying to each scheduled generation unit or scheduled load for the same period.

D.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 2016/17 as well as likely

513 South Australian black system event (28/9/2016 16:18 - 11/10/2016 22:30) has been excluded from the mean absolute percentage error forecasting analysis

reasons for the variations.[514] The data that the Panel has considered is disclosed in Table D.3.

Table D.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	4,016	52.2	3,448	52.4	4,715	53.2	6,257	49.5	3,289	29.9
Availability	2,621	34.1	2,308	35.1	3,254	36.7	4,850	38.4	7,722	70.1
Combination[515]	1,047	13.6	824	12.5	888	10.0	1,511	12.0	3	0.0
Network	5	0.1	0	0.0	1	0.0	13	0.1	4	0.0
Total	7,689	100.0	6,580	100.0	8,858	100.0	12,631	100.0	11,018	100.0
Trading intervals affected	6,375	36.4	5,557	31.7	7,676	43.8	10,105	57.7	10,076	57.5

Source: AER

A comparison of the NEM regions shows that South Australia reported the highest number of significant price variations in 2016/17. 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 increased in all regions from 2015/16.

D.5 Wind forecasts

The Australian wind energy forecasting system was implemented by AEMO in a two stage process. 'Phase 1' of the project was implemented internally in 2008 and then 'Phase 2' was completed in June 2010. The development of the system was funded by the then Commonwealth Department of Resources, Energy and Tourism involving a 'world first 'integrated system designed specifically for the NEM by a European consortium.[516]

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

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514 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. The AER must then review the reasons for the variation. The AER does this in each of its electricity weekly reports.

515 This could be the combination of changes in plant availability and changes in demand

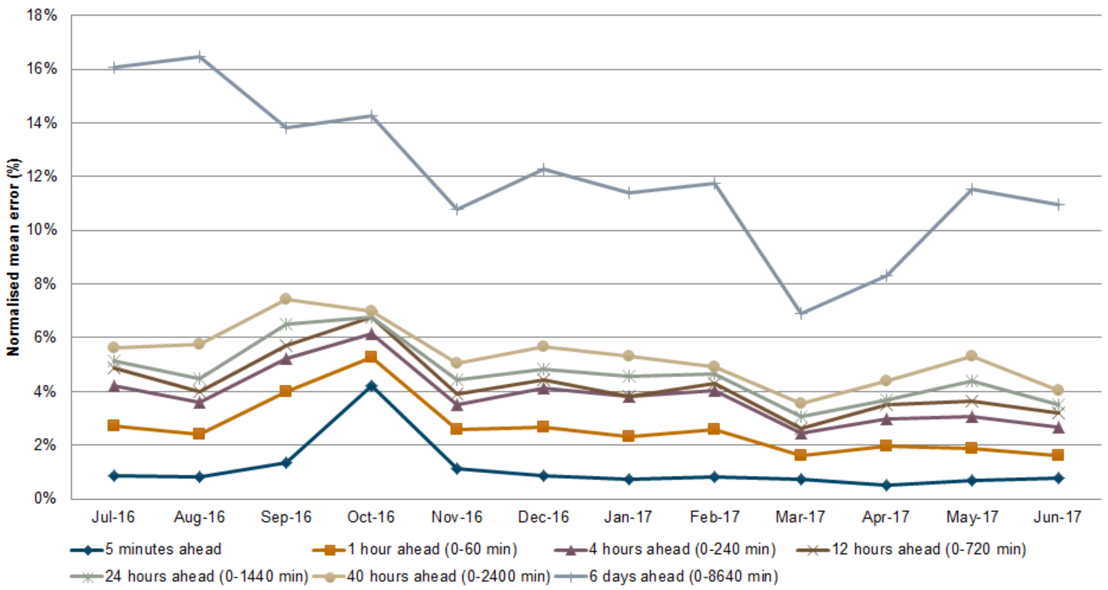
516 AEMO, *Australian Energy Forecasting System (AWEFS)*, September 2014.

information, standing data (wind farm details), weather forecasts, real time measurements and turbine availability information.

As set out in previous sections, the Panel recognises that wind generation capacity in the NEM is expected to continue to grow under Australia's LRET. 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 Australian wind energy forecasting system based on the average percentage error across all regions in the NEM. The performance for 2016/17 is depicted in Figure D.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. Uncharacteristic error values are recorded for September 2016 and October 2016 due to the South Australian black system event.

Figure D.3 Australian wind energy forecasts for 2016/17

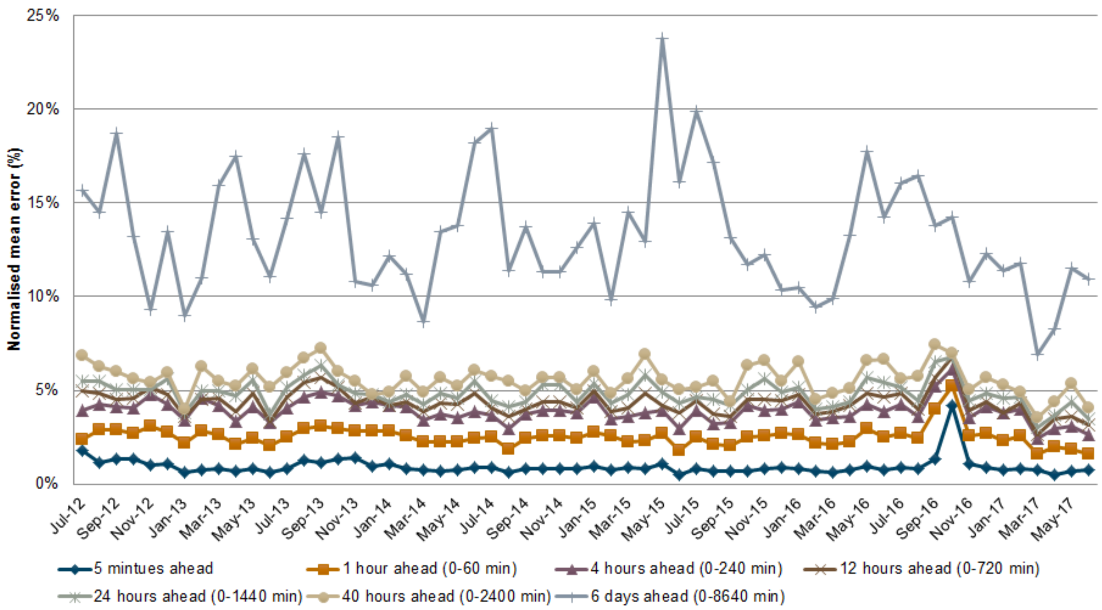


Source: AEMO

Figure D.4 shows the performance of the system from 2012/13 to 2016/17. 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 affect forecast performance.[517]

517 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.

Figure D.4 Australian wind energy forecasts from 2012 to 2017



Source: AEMO

E Weather summary

This appendix summarises weather conditions in 2016/17.

E.1 Seasonal weather summary

E.1.1 Winter 2016

Winter 2016 was Australia's equal sixth-warmest on record for mean temperatures. The rainfall observed for winter 2016 was the second highest on record, 82 per cent higher than the long term national winter average.

Increased cloud cover associated with the very wet winter, and very much warmer than average sea surface temperatures around much of Australia, helped maintain well above average minimum temperatures throughout the winter for each state.

E.1.2 Spring 2016

Across Australia, mean temperatures for spring 2016 were equal to the long term average. Spring 2016 was warmer than average across north and coastal eastern Australia. It was cooler than average across the eastern interior.

It was a relatively wet spring with rainfall 26 per cent above the long term national spring average. Spring was wetter than average across much of the southeast and interior. It was generally drier than average in the country's southwest and northeast.

E.1.3 Summer 2016/17

Summer 2016/17 mean temperatures for Australia were above the long term summer average. New South Wales recorded the highest mean maximum and overall mean temperatures on record for the state. Queensland recorded the second highest overall mean temperature on record for the state.[518]

The rainfall observed for summer 2016/17 was Australia's fourth highest on record, and was 49 per cent above the long term national summer average.

E.1.4 Autumn 2017

Across Australia, mean temperatures for autumn 2017 were above the long term national average. March was exceptionally warm for the eastern half of Australia.

Rainfall for autumn was slightly below average for Australia as a whole, but varied markedly across the country.

E.2 Notable periods during 2016/17

Table E.1 shows the highest and lowest temperatures recorded in the capital of each state in the NEM.

518 The warmth in New South Wales and Queensland was persistent across the season. High daily temperature records were set at a number of stations as well as numerous records for runs of consecutive warm days or total number of days for the month or the season above temperature thresholds (such as number of days reaching at least 30 °C).

Table E.1 Extreme temperatures (°C)

	Lowest temperature		Highest temperature	
City	**Temperature**	**Date**	**Temperature**	**Date**
Brisbane (CBD)	7.2	3 July 2016	37.6	12 February 2017
Sydney (Observatory Hill)	6.4	15 July 2016	39.4	31 January 2017
Canberra (Airport)	-5.2	3 July 2016	41.6	11 February 2017
Adelaide (Kent Town)	1.7	4 June 2017	42.4	8 February 2017
Melbourne (Olympic Park)	3.1	17 July 2016	38.2	28 December 2016
Hobart (Ellerslie Road)	0.6	22 June 2017	32.1	14 March 2017

Source: Bureau of Meteorology.

F 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.

F.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 the 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.

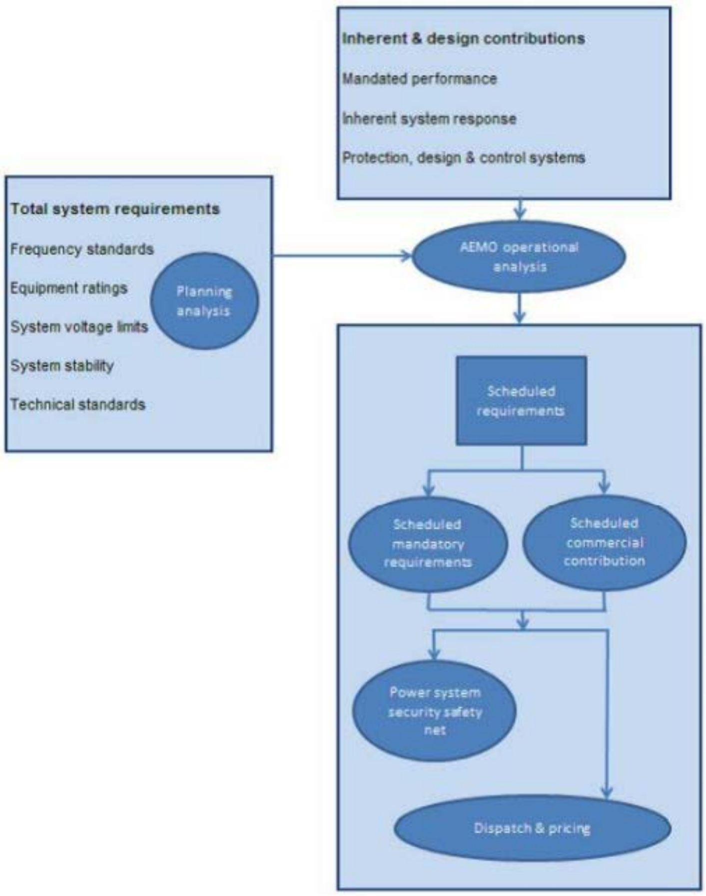
AEMO uses constraints provided by TNSPs in the NEM dispatch process to ensure that plant remains within rating and power transfers remain within stability limits so that the power system is in a secure operating state.[519] In the event that AEMO is not able to manage the secure and satisfactory limits, AEMO can exercise a number of options. These options are listed in AEMO's suggested priority order and may not all be available under all circumstances:

519 AEMO, *Power system security guidelines*, February 2017.

- revising plant thermal limits
- revising power system limits
- implement a plan such as a contingency plan or network support agreement
- reconfigure the network
- dispatch or activation of reserve contracts to address a power system security event
- if insufficient FCAS is available, issue a direction or instruction for a reduction in the size of the generation or load at risk
- instruct involuntary load shedding

Figure F.1 illustrates the overall arrangements for system security.

Figure F.1 System security model



Source: AEMO

F.1.1 Power system stability

Transferring large amounts of electricity between generators and consumers over long distances can potentially compromise the stability of the power system. 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 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.[520] 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.

AEMO's review of significant events in recent times shows that system damping and fault ride-through performances are generally within stipulated requirements. However, AEMO has highlighted the need to maintain adequate monitoring so that possible causes of instability can be located and addressed in a timely manner.

There have been a number of occasions, including in 2016/17, where these real-time monitoring tools have identified the need to reduce transfer capability.

On these occasions, the power system conditions at the time were used to review the transfer limits. This is because when the transfer limits were originally determined, these combinations of dispatch scenarios, power system configurations and faults may not have been considered due to their low likelihood of occurrence.

520 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.

F.2 System restart standard

The system restart standard sets out several key parameters for power system restoration, including the timeframe 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 having to undertake controlled shedding of customers. Restoration of load from these localised or controlled events is not covered by the system restart standard.

During 2014/15, AEMO undertook a tender process for procuring system restart services for the period 1 July 2015 to 30 June 2018. In June 2015, AEMO announced the outcome of its procurement of SRAS for that period. As a result of this tender, the total amount AEMO expects to spend on the acquisition of SRAS dropped from $55 million a year in 2014/15 to $21 million a year in 2015/16, representing a reduction of 62 per cent. This is still higher than the SRAS costs in the period before 2007/08, which were approximately $15 million.[521]

F.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 power system operators 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

521 AEMO, *System restart ancillary services 2015, Tender process report*, 2 July 2015.

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. For example, the access standard is designed to meet the frequency operating standards, which is a system standard. In defining the frequency operating standards, consideration would need to be given to the cost of plant in meeting the required access standards.

F.4 Registered performance standards

The performance of all generating plant must be registered with AEMO as a performance standard. Registered performance standards are derived from the access standards set out in section 5.2 of the rules. Registered performance standards represent binding obligations. To ensure a plant meets its registered performance standards on an ongoing basis, participants are also 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 technical standards regime, which came into effect in late 2003, "grandfathered" the performance of existing plant. This established a process to specify the registered standard of existing plant as the capability defined through any existing derogation, or connection agreement or the designed plant performance.[522]

Once set, a plant's performance standard does not vary unless an upgrade is required. Where that occurs, a variation in the connection agreement would be needed.

F.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 were reviewed by the Panel in 2017. The revised frequency operating standards are effective from 14 November 2017 and shown in the tables below.

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522 While the changes to the rules were introduced in March 2003, the period between November 2003 and November 2004 allowed for all existing generators to register their existing performance with National Electricity Market Management Company Limited (now AEMO).

F.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 F.1.[523]

Table F.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	
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 F.2.

Table F.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	47 to 52 Hz	49.0 to 51.0 Hz within	49.5 to 50.5 Hz within

523 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
further separation event	(reasonable endeavours)	2 minutes (reasonable endeavours)	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 F.3.

Table F.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.

F.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 F.4.

Table F.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	

Condition	Containment	Stabilisation	Recovery
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 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple 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 F.5.

Table F.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.[524]

F.6 Network constraints

The ability to transfer power across the system is limited by a number of factors including the capacity of the network.[525] Secure operation of the power system

524 OFGSS refers to the over frequency generator shedding scheme

525 The capability of the network to transfer power depends on a number of factors including; the capacity of network elements as indicated by their thermal, and fault ratings, the availability of

requires AEMO to maintain power flows within the capability of the network after allowing for credible contingencies.

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.

F.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 F.6 displays the yearly constraint changes since 2011 in NEMDE

Table F.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

Source: AEMO, *NEM Constraint report 2016*, June 2017, p. 3

The 2016 year experienced the second largest number of constraint equation changes since the start of the NEM. The major contributor to the high number of constraint

spare capacity to accommodate sudden load increases following contingencies, the availability and location of generation, reactive plant that define voltage and stability related power transfer limits.

equation changes was the Heywood Interconnector upgrade project in South Australia.[526]

F.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 F.7 outlines the top five binding constraints impacting the NEM during 2016/17.[527]

Table F.7 Top five binding constraints impacting the NEM during 2016/17

Constraint	Hours binding	Description
N^^V_NIL_1	886.58	This constraint avoids voltage collapse in southern New South Wales for the loss of the largest Victorian generator or Basslink.
V>>V_NIL_2A_R	677.75	This constraint helps to maintain flow on the South Morang F2 transformer below its continuous rating.
V::N_NIL_V2	659.58	This constraint avoids transient instability for the fault and trip of a Hazelwood to South Morang 500 kV. It is one of twelve constraint equations that make up the transient stability export limit from Victoria.
N_X_MBTE_3B	591.58	This constraint binds when all three Directlink cables are out.
V_S_NIL_ROCOF	527.5	This constraint equation was introduced in 2016 on advice from the South Australian government that the RoCoF needed to be limited to 3 Hz/s following the loss of the Heywood interconnector .

Source: AEMO

526 AEMO, *NEM Constraint report 2016*, June 2017, p. 8

527 Note that section G.7.1 reports changes to constraint equations on a calendar year basis whereas this section reports on top binding constraints on a financial year basis.

F.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.[528]

AEMO issued 4,520 market notices during 2016/17, compared to 4,937 in 2015/16 and 3,268 in 2014/15. The number and type of market notices issued by AEMO are summarised in Table F.8. During 2016/17, AEMO issued significantly more market notices of the following types relative to the previous two years: administered price cap, market intervention and settlements residue.

Table F.8 Market notices issued by AEMO

Type of notice	Number of notices		
	2014/15	**2015/16**	**2016/17**
Administered price cap	0	32	78
General notice	123	81	173
Inter-regional transfer	249	354	414
Market intervention	9	2	40
Market systems	86	161	159
Manual priced dispatch interval	0	0	0
NEM systems	1	3	0
Non-conformance	614	509	371
Power system event	87	72	76
Price adjustments	0	0	0
Prices subject to review	213	781	523
Prices unchanged	210	776	518
Process review	0	0	0
Reclassify contingency	1432	1686	1495
Reserve notice	194	400	447
Settlements residue	20	56	190

528 In accordance with clause 4.8 of the rules.

Type of notice	Number of notices		
	2014/15	2015/16	2016/17
Total[529]	3268	4937	4520

Source: AEMO

F.8 Summary of AEMO's recommendations from its investigation of the 2016 South Australian black system event

AEMO made 19 recommendations following its review into the black system event that occurred in South Australia on 28 September 2016. These recommendations include:[530]

1. AEMO to propose to ESCOSA changes to generator licensing conditions, and also to request similar changes to the rules, to address deficiencies in performance standards identified through this investigation.
2. AEMO to put in place more rigorous processes to monitor weather warnings for changes to forecasts, to trigger reassessment of reclassification decisions where relevant.
3. AEMO to review and implement, following consultation, a more structured process for reclassification decisions when faced with power system risks due to extreme wind speeds.
4. AEMO to assess options for improved forecasting of when wind speeds will exceed protection settings on wind turbines, which would lead to 'over-speed cut-outs'.
5. AEMO to consider development of a new generator reclassification process to manage generator 'type' risks , including how information about potential risks will be sought, and the most appropriate methods to manage power system security during such a generator reclassification.
6. AEMO to work with ElectraNet to determine the feasibility of developing a special protection scheme to operate in response to sudden excessive flows on the Heywood Interconnector, and to initiate load shedding with a response time fast enough to prevent separation.
7. AEMO to modify existing transfer limits on the Heywood Interconnector to take into account the fact that the largest credible generator contingency under conditions of high wind generation is greater than previously assumed.
8. AEMO to modify operational procedures for South Australia island operation to:
   - Take into account the fact that, under islanded conditions, system strength may fall to a level where some wind farms might not be able to ride through credible voltage disturbances.

529 Also includes participant notices.

530 AEMO, *Black system South Australia, 28 September 2016, final report,* March 2017, p. 9.

- Ensure that maintenance of adequate system strength is incorporated into the transmission planning process in a more systematic manner.

9. AEMO to support ElectraNet to identify and address any specific risks to the operation of protection systems due to the low levels of system strength that may be experienced if South Australia is islanded.
10. AEMO to support ElectraNet in reassessing control strategies to achieve very rapid switching of reactive plant to manage the risk of severe over voltages in South Australia that might occur due to large levels of under frequency load shedding following separation.
11. AEMO to review its reclassification procedures to address any remaining material risk due to multiple voltage disturbances, and to approach relevant Generators to review the feasibility of increasing plant limits for the maximum number of multiple voltage disturbances that can be tolerated over a 30-minute period.
12. AEMO, together with the South Australian System Restart Working Group, to review the system restart process in detail to determine efficiencies and to implement relevant recommendations from the Reliability Panel. These learnings will be shared across all Australian jurisdictions
13. Any differences between SRAS test plans and the restart process set out in a system restart plan and associated local black system procedures to be identified and explained by AEMO, to ensure the test simulates, as far as practicable, the conditions that will be encountered in a real restart situation
14. Similarly, where the restart procedure depends initially on starting a low voltage generator, the start of this generator alone to be tested on a regular basis, in addition to the annual test of the entire SRAS source
15. AEMO to develop detailed procedures for in power system operations during periods of market suspension, and identify if any rules changes are desirable to improve the process
16. AEMO to investigate a better approach to ensuring that the minimum stable operating levels of generating units are taken into account in the dispatch process
17. AEMO to review market processes and systems, in collaboration with participants, to identify improvements and any associated rules or procedure changes that may be necessary to implement those improvements
18. AEMO to develop a more structured process in consultation with participants to source and capture data after a major event in a timely manner and to co-ordinate data requests.
19. AEMO to investigate with participants the possibility of introducing a process to synchronise all high speed recorders to a common time standard.

G Safety framework

As noted in Chapter 5, 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 of the 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.

G.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 fundamentally changed Queensland's approach to electrical safety, establishing a Commissioner for Electrical Safety, an Electrical Safety Board and three Board committees to advise the Minister on electrical safety issues. Additionally, an independent state-wide electrical safety inspectorate was established to administer and enforce the new legislative requirements.

One of the responsibilities of the Electrical Safety Board is the development of a five year strategic plan for improving electrical safety in Queensland. The Electrical Safety Plan for Queensland 2014–2019 was published in 2013 and sets out strategies designed to achieve the Board's goal of eliminating all preventable electrical deaths in Queensland by 2019.

G.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*). 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)*.

G.3 Australian Capital Territory

The ACT Planning and Land Authority administers the *Electricity Safety Act 1971 (ACT)* and *Electricity Safety Regulation 1971 (ACT)* in the Australian Capital Territory. This legislation 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
- 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.

G.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.

G.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.

G.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 Workplace Standards Tasmania via an amendment to the *Electricity Industry Safety and Administration Act 1997 (Tas)* in 2009.

H Pricing review

This chapter summarises the major pricing events during 2016/17.

AEMO publishes reports on significant price events in order to promote market transparency.[531] The reports explain:

- the factors contributing to unusual pricing outcomes
- whether outcomes were consistent with dispatch offers and power system conditions
- the performance of pre-dispatch in forecasting the unusual outcomes.

The reports are produced when:

- the maximum daily spot price (trading interval price) in any region is more than $2,000/MWh[532]
- the minimum daily spot price for any region is less than -$100/MWh
- the maximum daily sum of FCAS half hourly averaged prices exceeds:
  - $3,000/MWh in Tasmania
  - $150/MWh in all other regions of the NEM.

During 2016/17, there were 87 pricing events in the spot market. 13 of these prices events were negative and in 67 of these price events the price exceeded $2000/MWh. The majority of the pricing events recorded occurred in South Australia. Over the same period there were 52 pricing events in the FCAS markets, in 25 of these events the price exceeded $2000/MWh.

Table H.1 displays the top five and bottom two spot price events in the NEM during 2016/17.

- The highest spot price for a trading interval was recorded in New South Wales on 10 February 2017 and can be attributed to high demand, unplanned generator outages and insufficient scheduled generator capacity with interconnectors constrained and limited lower priced generation.[533]
- The second highest spot price for a trading interval was recorded in Queensland on 13 January 2017 and was mainly due to the rebidding and shifting of

531 The reports, and more information regarding the reports, are available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports

532 AEMO may also publish a brief report if the maximum daily spot price in any region is between $500/MWh and $2,000/MWh

533 More information on the events of 10 February 2017 is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Pricing-Event-Reports/Feb-2017/10-February-2017--High-energy-price-SA-NSW-QLD-High-FCAS-price-Mainland.pdf

generation capacity, during a period of high demand, while interconnector support was constrained.[534]

- The third highest spot price event occurred in South Australia on 1 December 2016 and resulted from a trip of a significant part of the Heywood interconnector that was followed by a rebidding/shifting of generation capacity, with cheaper priced generation capacity limited.[535]
- The fourth highest spot price event occurred in South Australia on 8 February 2017 and was caused by high demand which was higher than forecast, insufficient scheduled generator capacity and low wind generation, while interconnector support was constrained.[536]
- The fifth highest spot price event was recorded in Queensland on 2 February 2017 and can be mainly explained by high demand, while interconnectors were constrained and lower priced generation was limited.[537]

Table H.1 Notable pricing events in the NEM during 2016/17

Date	Region	Trading interval (ending)	Price per MWh
Top five spot pricing events			
10-Feb-17	New South Wales	6 trading intervals between 16:00 and 18:30	$2,088.32 to $14,000.00
13-Jan-17	Queensland	8 trading intervals between 7:00 and 20:30	$2,200.28 to $13,882.77
1-Dec-16	South Australia	10 trading intervals between 0:30 and 5:00, and 10:00 and 10:30	$1,963.32 to $13,766.58
8-Feb-17	South Australia	7 trading intervals between 15:30 and 19:30	$2,481.99 to $13,440.01
2-Feb-17	Queensland	6 trading intervals between 15:30 and	$2,183.77 to

534 More information on the events of 13 January 2016 is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Pricing-Event-Reports/Jan-2017/13-January-2017---High-Energy-price-QLD.pdf

535 More information on the events of 1 December 2016 is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Pricing-Event-Reports/Dec-2016/1-December-2016---High-Energy-and-FCAS-price-SA.pdf

536 More information on the events of 8 February 2017 is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Pricing-Event-Reports/Feb-2017/08-February-2017---High-energy-price-SA.pdf

537 More information on the events of 2 February 2017 is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Pricing-Event-Reports/Feb-2017/02-February-2017---High-energy-price-QLD.pd

Date	Region	Trading interval (ending)	Price per MWh
		19:00	$13,399.95
Bottom two spot pricing events			
12-Feb-17	Victoria	2:30	-$319.03
22-Nov-16	Tasmania	14:30	-$289.19

Table H.2 displays the top five FCAS pricing events in the NEM during 2016/17.[538]

Table H.2 Top five FCAS pricing events

Date	Region	FCAS Service	Trading interval (ending)	Price per MWh
18-Apr-17	South Australia	Raise Regulation and Lower Regulation	11:30 to 23:00	$299.99 to $13,348.11
18-Oct-16 to 22-Oct-16	South Australia	Raise Regulation	All trading intervals between 07:30 on 18-Oct-16 and 11:00 on 22-Oct-16	$74.69 to $13,083.33
31-Aug-16 to 1-Sep-16	South Australia	Raise Regulation and Lower Regulation	All trading intervals between 07:30 on 31-Aug-16 and 17:30 on 1-Sep-16	$286 to $12,899.99
2-Sep-16	South Australia	Raise Regulation and Lower Regulation	7:30 to 16:00	$286 to $12,899.99
18-Oct-16 to 22-Oct-16	South Australia	Lower Regulation	all trading intervals between 07:30 on 18-Oct-16 and 11:00 hrs on 22-Oct-16	$74.69 to $12,306

Table H.3 lists the spot price events in the NEM during 2016/17.[539]

538 Source: AEMO, Pricing Event Reports, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports.

Table H.3 Spot price events for July 2016 to June 2017

Period	Date	Region	Trading interval (ending)	Price per MWh
Jul-16	6-Jul-16 to 8-Jul-16	South Australia	41 trading intervals between 6:00 on 6-Jul-16 and 00:00 on 9-Jul-16	$508.89 to $8,897.80
	11-Jul-16	South Australia	0:00	$2,324.03
		Victoria	0:00	-$196.93
	12-Jul-16	South Australia	6 trading intervals between 9:00 and 18:30	$951.26 to $2,815.68
		Tasmania	9:00 and 21:00	$1,695.07 and $602.95, respectively
	13-Jul-16	South Australia	8 trading intervals between 6:30 on 13-Jul-2016 and 00:00 on 14-Jul-16	$547.60 to $7,068.49
	14-Jul-16	South Australia	13 trading intervals between 9:00 and 21:00	$534.26 to $6,917.55
	16-Jul-16	South Australia	18:00 and 19:00	$1,992.34 and $1,910.47, respectively
	18-Jul-16	South Australia	17:00	$1,930.20
	19-Jul-16	South Australia	7:00	$1,659.54
	22-Jul-16	South Australia	9:30	$2,380.68
		South Australia	16:30 and 17:00	$2,484.65 and $2,337.47, respectively
	27-Jul-16	Tasmania	18:30	$1,736.90

539 Source: AEMO, Pricing Event Reports, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports.

Period	Date	Region	Trading interval (ending)	Price per MWh
	28-Jul-16	Tasmania	9:30	$2,402.02
Aug-16	1-Aug-16	South Australia	9:30	$4,772.49
Sep-16	5-Sep-16	South Australia	0:00	$2,361.27
	6-Sep-16 to 10-Sep-16	South Australia	21:00 on 8-Sep-16 and 15:00 on 9-Sep-16	$1,783.47 and -$144.15, respectively
Oct-16	6-Oct-15	Tasmania	6:30	$2,419.85
	10-Oct-16	Tasmania	10:00	$618.67
	26-Oct-16	South Australia	0:00	$4,708.99
	31-Oct-16	Tasmania	9:30	$894.35
Nov-16	1-Nov-16	South Australia	7:30	$2,298.56
	8-Nov-16	New South Wales	15:30	$2,190.99
		Queensland	15:30	$2,029.11
	14-Nov-16	South Australia	14:00	$2,342.76
	18-Nov-16	New South Wales	15:00 to 16:30	$587.87 to $11,700.63
	21-Nov-16	Queensland	5:30	-$155.28
	22-Nov-16	South Australia	14:30	-$184.53
		Victoria	14:30	-$289.19
	30-Nov-16	South Australia	11:00	$4,605.06
		Tasmania	12:30	$2,392.93
Dec-16	1-Dec-16	South Australia	10 trading intervals between 0:30 and 5:00, and 10:00 and 10:30	$1,963.32 to $13,766.58
		South Australia	11:00	-$112.62
	5-Dec-16	Victoria	14:30	-$156.69
	11-Dec-16	South Australia	0:00	$2,347.55
	12-Dec-16	South Australia	18:00	$2,493.61

Period	Date	Region	Trading interval (ending)	Price per MWh
	16-Dec-16	Queensland	6:30	$2,434.05
	20-Dec-16	South Australia	1:00 and 2:30	$2,604.47 and $2,223.87, respectively
		Victoria	1:00	-$150.11
		Tasmania	10:00	$2,120.26
	30-Dec-16	Queensland	16:30	$2,179.52
	31-Dec-16	Queensland	14:00	$2,342.24
Jan-17	7-Jan-17	South Australia	16:30	$2,357.40
	11-Jan-17	Queensland	23:00	$2,361.08
	12-Jan-17	Queensland	7 trading intervals between 13:00 and 19:00	$2,343.31 to $2,578.37
	13-Jan-17	Queensland	8 trading intervals between 7:00 and 20:30	$2,200.28 to $13,882.77
	14-Jan-17	Queensland	14 trading intervals between 7:00 and 23:00	$2,195.38 to $12,641.69
	15-Jan-17	Queensland	12:30	$2,609.08
	18-Jan-17	Queensland	17:00	$2,404.56
	19-Jan-17	South Australia	17:00	$2,399.21
	20-Jan-17	Queensland	15:00 and 17:00	$2,382.27 and $2,457.65, respectively
	23-Jan-17	South Australia	5:30	$2,458.04
	24-Jan-17	Queensland	17:00	$2,339.11
	26-Jan-17	Queensland	17:00	$2,188.39
	27-Jan-17	Queensland	11:00	$2,353.04
	29-Jan-17	Queensland	16:30 and 18:30	$2,408.10 and $2,339.46, respectively

Period	Date	Region	Trading interval (ending)	Price per MWh
	30-Jan-17	Queensland	7:00 and 17:00	$2,377.63 and $2,423.63, respectively
		New South Wales	17:00	$2,346.05
		Tasmania	17:00	-$168.30
	31-Jan-17	Queensland	16:00 and 16:30	$2,297.84 and $2,367.31, respectively
Feb-17	1-Feb-17	Queensland	1:00, 12:00, 16:30, 17:30 and 18:30	$2,245.84 to $2,350.60
	2-Feb-17	Queensland	6 trading intervals between 15:30 and 19:00	$2,183.77 to $13,399.95
	3-Feb-17	Queensland	17:00	$2,389.49
	5-Feb-17	Queensland	16:00	$2,351.78
	6-Feb-17	Queensland	15:30 to 17:00	$2,532.09 to $11,027.91
		New South Wales	15:30 to 17:00	$2,741.78 to $11,692.09
	7-Feb-17	Queensland	7:00	$2,381.04
	8-Feb-16	South Australia	7 trading intervals between 15:30 and 19:30	$2,481.99 to $13,440.01
	9-Feb-17	Victoria	18:30	-$154.64
		Tasmania	18:30	-$149.43
		South Australia	16:30 to 17:30; 18:30	$2,322.15 to $8,957.71; $9,509.52, respectively
		Queensland	16:30 to 17:30	$2,322.15 to $8,957.71
		New South Wales	16:30 to 17:30	$2,322.15 to $8,957.71
	10-Feb-17	Queensland	16:30 and 17:00	$3,460.47 and

Period	Date	Region	Trading interval (ending)	Price per MWh
				$12,221.40, respectively
		New South Wales	6 trading intervals between 16:00 and 18:30	$2,088.32 to $14,000.00
		South Australia	15:30	$2,112.80
	11-Feb-17	Queensland	5 trading intervals between 15:30 and 17:30	$2,232.51 to $8,568.90
	12-Feb-17	Queensland	6 trading intervals between 17:00 and 19:30	$2,259.16 to $9,004.95
		Victoria	2:30	-$319.03
	13-Feb-17	Queensland	14:00	$2,296.01
	27-Feb-17	South Australia	5:00	$2,380.81
Mar-17	1-Mar-17	South Australia	15:30	$2,603.24
	3-Mar-17	South Australia	15:30	$4,921.39
	12-Mar-17	South Australia	22:00	-$146.29
	20-Mar-17 to 21-Mar-17	South Australia	13:00 and 14:00 on 20-Mar-17; 11:30 on 21-Mar-17	$1,958.44 and $2,651.96; $2,402.10, respectively
Apr-17	No published reports on significant price events			
May-17	16-May-17	Tasmania	1:00	$2,108.62
Jun-17	15-Jun-17 to 18-Jun-17	Tasmania	12:30 on 15-Jun-17; 6:30 and 21:30 on 16-Jun-17; 1:00 on 18-Jun-17	$2,092.15; $2,132.69 and $2,100.28; $2,162.23, respectively

Table H.4 summarises the FCAS price events in the NEM during 2016/17.[540]

540 Source: AEMO, Pricing Event Reports, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports.

Table H.4 FCAS price events for July 2016 to June 2017

Period	Date	Region	FCAS Service	Trading Interval (ending)	Price per MWh
Jul-16	2-Jul-16	Mainland	Raise Regulation	23:30	$249.97
		Mainland	Fast Raise	23:30	$100.21
	4-Jul-16	Mainland	Raise Regulation	7:00 and 9:30	$93.44 and $140.21, respectively
	5-Jul-16	NEM	Raise Regulation	10:00; 10:30 and 12:00	$151.52; $239.85 and $169.77, respectively
Aug-16	10-Aug-16	South Australia	Raise Regulation	34 trading intervals between 07:30 on 10-Aug-16 and 00:00 on 11-Aug-16	$97.85 to $2,751.37
		South Australia	Lower Regulation	29 trading intervals between 10:00 on 10-Aug-16 and 00:00 on 11-Aug-16	$57.45 to $4,064.46
	11-Aug-16 to 12-Aug-16	South Australia	Raise Regulation and Lower Regulation	all trading intervals between 00:30 on 11-Aug-16 to 13:30 on 12-Aug-16	$96.69 to $11,469.00
	31-Aug-16 to 1-Sep-16	South Australia	Raise Regulation and Lower Regulation	all trading intervals between 07:30 on 31-Aug-16 and 17:30 on 1-Sep-16	$286 to $12,899.99
Sep-16	2-Sep-16	South Australia	Raise Regulation and Lower Regulation	7:30 to 16:00	$286 to $12,899.99
	6-Sep-16 to 10-Sep-16	South Australia	Raise Regulation	all trading intervals between 7:30	$98 to $452.66

Period	Date	Region	FCAS Service	Trading Interval (ending)	Price per MWh
				on 6-Sep-16 and 18:00 on 10-Sep-16	
		South Australia	Lower Regulation	196 trading intervals between 07:30 on 6-Sep-16 and 18:00 on 10-Sep-16	$77.50 to $300
	13-Sep-16	South Australia	Raise Regulation	7:30	$2,399.99
		South Australia	Lower Regulation	7:30	$2,316.23
		South Australia	Raise Regulation and Lower Regulation	08:00 to 17:30	$151.51 to $307.05
	16-Sep-16	South Australia	Raise Regulation and Lower Regulation	07:30 to 11:00	$599 to $4,232.77
		South Australia	Raise Regulation and Lower Regulation	11:30 to 15:30	$7,875.50 to $11,250
		Mainland	Fast Raise	19:00	$65.99
	27-Sep-16	Mainland	Raise Regulation	19:00	$96.92
	29-Sep-16	Queensland, New South Wales, Victoria	Lower Regulation	23:30	$63.80
		Queensland, New South Wales, Victoria	Raise Regulation	23:30	$33.88
		Queensland, New South Wales, Victoria	Fast Raise	23:30	$25.81
		Queensland, New South Wales,	Slow Raise	23:30	$45.18

Period	Date	Region	FCAS Service	Trading Interval (ending)	Price per MWh
		Victoria			
Oct-16	18-Oct-16 to 22-Oct-16	South Australia	Raise Regulation	all trading intervals between 07:30 on 18-Oct-16 and 11:00 on 22-Oct-16	$74.69 to $13,083.33
		South Australia	Lower Regulation	all trading intervals between 07:30 on 18-Oct-16 and 11:00 hrs on 22-Oct-16	$74.69 to $12,306
	30-Oct-16	Mainland	Raise	2:30 to 5:00	$14.83 and $39.78
		Mainland	Delayed Lower and Lower Regulation	2:30 to 5:00	$20.80 to $47.83
Nov-16	8-Nov-16 to 9-Nov-16	South Australia	Raise Regulation	32 trading intervals between 22:30 on 8-Nov-16 and 19:00 on 9-Nov-16 32 trading intervals between 22:30 on 8-Nov-16 and 19:00 hrs on 9-Nov-16	$304.41 to $7,331.95
		South Australia	Lower Regulation	55 trading intervals between 7:00 on 8-Nov-16 and 19:00 on 9-Nov-16 32 trading intervals between 22:30 on 8-Nov-16 and 19:00 hrs on 9-Nov-16	$300.04 to $7,333.94
	22-Nov-16 to	South	Raise	40 trading intervals	$300.03 to

Period	Date	Region	FCAS Service	Trading Interval (ending)	Price per MWh
	26-Nov-16	Australia	Regulation	between 07:30 on 22-Nov-16 and 10:00 on 26-Nov-16 40 trading intervals between 07:30 on 22-Nov-16 and 10:00 on 26-Nov-16	$10,997.33
		South Australia	Lower Regulation	99 trading intervals between 07:30 on 22-Nov-16 and 10:00 on 26-Nov-16 40 trading intervals between 07:30 on 22-Nov-16 and 10:00 on 26-Nov-16	$300.01 to $11,014.17
	30-Nov-16	South Australia	Raise Regulation and Lower Regulation	all trading intervals between 6:30 on 30-Nov-16 and 0:00 on 1-Dec-16 6:30 on 30-Nov-16 to 0:00 on 1-Dec-16	$299 to $300
		South Australia	Fast Lower, Slow Lower and Delayed Lower	11:00 and 11:30 40 trading intervals between 07:30 on 22-Nov-16 and 10:00 on 26-Nov-16	$149.22 and $300
Dec-16	1-Dec-16	Tasmania	Raise	3:30	$11,667.02 to $11,670.00
		South Australia	Regulation	1:00 to 5:30	$300.00

Period	Date	Region	FCAS Service	Trading Interval (ending)	Price per MWh
		South Australia	Contingency	1:00 to 4:30	$300.00
		South Australia	Lower Regulation and Lower Contingency	10:30	$300.00
	14-Dec-16 to 15-Dec-16	South Australia	Raise Regulation	11 trading intervals between 6:30 on 14-Dec-16 and 0:00 on 15-Dec-16	$300.02 to $545.69
	22-Dec-16	South Australia	Lower Regulation	43 trading intervals between 11:00 on 14-Dec-16 and 14:00 on 15-Dec-16	$300.06 to $370.61
		South Australia	Raise and Lower Regulation	5 trading intervals between 07:30 and 10:00	$421.89 to $4,874.57
	23-Dec-16	South Australia	Raise and Lower Regulation	4 trading intervals between 7:30 and 12:00 four trading intervals (TIs) between TIs ending 0730 hrs and 4 trading intervals between 7:30 and 12:00	$808.98 to $5,680.42
Jan-17	23-Jan-17	South Australia	Raise Regulation	5:30 and 6:00	$4,671.60 and $9,921.41, respectively
		South Australia	Lower Regulation	5:30 and 6:00	$6,904.69 and $9,234.86, respectively
Feb-17	6-Feb-17	Mainland	Raise Regulation	16:00	$478.54

Period	Date	Region	FCAS Service	Trading Interval (ending)	Price per MWh
	9-Feb-17	Mainland	Raise Regulation	15:00	$302.54
	10-Feb-17	Mainland	Raise Regulation	8 trading intervals between 13:30 and 18:00	$302.18 to $1,348.94
		Mainland	Delayed Raise	16:00	$1,292.68
	27-Feb-17	South Australia	Lower Regulation	5:00	$2,317.20
Mar-17	7-Mar-17	South Australia	Raise Regulation and Lower Regulation	5:00 to 6:30	$2,395.83 to $2,563.91
	20-Mar-17	South Australia	Raise Regulation	9:00 and 14:30	$2,404.51 and $459.06, respectively
		South Australia	Lower Regulation	12:00 and 13:00	$2,227.00 and $388.20
	26-Mar-17	Mainland	Raise Regulation	16:00	$472.66
Apr-17	18-Apr-17	South Australia	Raise Regulation and Lower Regulation	11:30 to 23:00	$299.99 to $13,348.11
May-17	No published reports on significant price events				
Jun-17	No published reports on significant price events				

I Market price cap and cumulative price threshold

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 2016/17, the values for the market price cap and the cumulative price threshold are tabulated in Table I.1.

Table I.1 2016/17 market price cap and cumulative price threshold values

	From 1 July 2015 to 30 June 2016	**From 1 July 2016 to 30 June 2017**
Market price cap	$13,800 / MWh	$14,000 / MWh
Cumulative price threshold	$207,000	$210,100

Market price cap

During 2016/17, the market price cap was reached 170 times in the energy market. The market price cap was reached 66 times in FCAS markets.[541] The main reasons for the market price cap being reached were generator rebidding, periods of high demand and interconnector constraints.

Cumulative price threshold

During 2016/17, the cumulative price threshold was not reached in the energy market. The cumulative price threshold was reached five times in FCAS markets. All five instances occurred in South Australia and at each occurrence when there was an outage on one of the two Heywood interconnector lines which was followed by generators rebidding into a higher price band.[542]

541 Market price cap events in FCAS markets occurred only in South Australia and Tasmania in 2016/17.

542 An outage on one of the two Heywood lines means there is an increased risk of South Australia separating from the NEM, and the loss of Heywood is a credible contingency. This means that FCAS must be procured locally.

J 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 2016/17.

J.1 Emissions reduction fund

Following the repeal of the carbon tax in July 2014, the Federal government introduced the Emissions Reduction Fund.[543] 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.

J.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.[544]

J.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).

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543 More information on the ERF is available at https://www.environment.gov.au/climate-change/emissions-reduction-fund

544 Australian Government Department of the Environment and Energy, *2017 Review of climate change policies*, December 2017, p. 5.

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 RET 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 RET 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.

J.4 Jurisdiction-based renewable energy targets

Some proposed 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.[545]
- **Queensland:** 50 per cent of generation provided to Queensland to come from renewable sources by 2030. It is not yet clear how this generation will be procured and what the location of this generation will be.[546]
- **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.[547]

545 ACT Government, *Canberra 100% renewable*,

546 For more information, see: https://www.dews.qld.gov.au/electricity/solar/solar-future

547 For more information, see: http://www.delwp.vic.gov.au/energy/renewable-energy/victorias-renewable-energy-targets

K 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 section 116 of the National Electricity Law AEMO may issue directions. Section 116 directions may include directions as issued under clause 4.8.9 of the rules (e.g. directing a

	scheduled generator to increase output) or clause 4.8.9 instructions (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 rules clause 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.
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.
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 or rules)	The rules came into effect on 1 July 2005, replacing the National Electricity Code.
National electricity system	The generating systems, transmission and distribution networks and other facilities owned, controlled or operated in the states and territories participating in the National Electricity Market.
Network	The apparatus, equipment and buildings used to convey and control the conveyance of electricity. This applies to both transmission networks 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); 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 is in a satisfactory operating state; and • 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 rules clause 4.8.9; • no load shedding is occurring or expected to occur anywhere on the power system under rules clause 4.8.9; and • 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* explanation.
Reliability of supply	The likelihood of having sufficient capacity (generation or demand-side response) to meet demand (the consumer load).
Reliability Standard	The 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* explanation.
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* explanation.
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 rules.
Spot price	The price for electricity in a trading interval at a regional reference node or a connection point.
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.