# AEMO observations: Operational and market challenges to reliability and security in the NEM

March 2018

# Important notice

## PURPOSE

The purpose of this document is to provide information to the Energy Security Board about operational and market challenges to reliability and security in the National Electricity Market.

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# Executive summary

Power systems and energy markets in Australia and overseas are undergoing rapid transformational change. In the years since the reliability rules governing the National Electricity Market (NEM) were designed, the system has gone from one that had excess capacity and was dominated by central large-scale, synchronous power plants, and passive consumption, to the current environment with rapid increase of both distributed energy resources[1] and wind and solar energy, coupled with retirement, or impending retirement, of conventional plant. The immediate future is expected to see growth in battery storage, pumped hydro, and connected and standalone micro grids and micro markets.

Ensuring market arrangements are structured in a way that draws on and co-optimises the diversity of resources available will deliver improved customer outcomes.

The NEM has served Australia's energy customers well for many years, but, as with all markets undergoing transformation, it is appropriate to consider whether aspects of the arrangements continue to be fit for purpose, and reflect the dynamic and evolving needs of future energy customers. This is particularly important at a time where affordability is a challenge for many energy customers, and satisfaction with value for money of electricity is down across most NEM regions[2].

In this document, AEMO has provided an overview of how changes are impacting operation of the power system in Australia and consequently reliability and security in the NEM. We have broken down the discussion into three key parts, resulting in a number of recommendations highlighted for potential market reform to preserve system efficiency, security, and reliability as well as improve affordability and emission objectives. The three key parts are:

1. The transformational changes occurring at the 'macro' level, and how these changes are transforming the operation of the power system.
2. The impact of the changes occurring with respect to power system operations, that is, the 'micro' level. These changes are impacting on how we must operate the system, and changing the measures and resources we require to ensure the system is reliable and secure.
3. Propositions for potential reform to address the impact of these operating and market challenges. In highlighting these proposals, we reflect on the experience of other systems and markets to consider how different operators and policy-makers are seeking to address the effects of similar challenges and emerging characteristics in their own contexts.

AEMO has sought to highlight where security and reliability needs may be shifting across the NEM on the back of changes in supply mix, electricity demand, and impact of weather. The table below summarises key changes and the key operational challenges AEMO, as system and market operator, is now seeing in relation to those changes.

**Table 1 Key system changes and operational challenges**

| Issue | What we are seeing | Operational implications | Potential avenues to address |
|---|---|---|---|
| Changing supply mix | • More variable renewable energy<br>• Less dispatchable generation<br>• Older resources | • Increased variability and uncertainty in the resource mix<br>• Increased reliance on directions | • Forecasting improvements<br>• Valuing flexible performance<br>• Strategic reserves<br>• Day-ahead markets<br>• Integrated system planning |

[1] AEMO defines distributed energy resources to include resources located on the distribution system that can supply or help manage energy on the system, including distributed and rooftop solar, storage, load management, and other forms of supply, including connected micro grids.

[2] Satisfaction on this measure has decreased by as much as 17% in the ACT and 11% in Victoria (noting that the Tasmanian Government has capped wholesale price increases for twelve months). Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2017, available at http://energyconsumersaustralia.com.au/publication/energy-consumer-sentiment-survey-findings-december-2017/.

| Issue | What we are seeing | Operational implications | Potential avenues to address |
|---|---|---|---|
| Changing electricity demand | • Higher ramps for peaks<br>• Lower minimum demand<br>• More active consumers<br>• More distributed energy resources (DER) | • Increased variability and uncertainty in demand<br>• Erosion of baseload<br>• Increased ramping requirement | • Forecasting improvements<br>• Use of DER<br>• Valuing flexible performance<br>• Strategic reserves<br>• Day-ahead markets<br>• Integrated system planning |
| Changing impact of weather | • Temperature changes<br>• Extremity of weather events | • Increased demand<br>• Increased stress on system over prolonged heat periods<br>• Increased risk of disruption<br>• Increased uncertainty | • Planning operating standards<br>• Use of DER<br>• Optimising utilisation of demand side response – for reserves to manage uncertainty and support greater system resilience<br>• Forecasting improvements |

## The changing power system

It is clear that the resources available to supply electricity in the NEM are undergoing a major transformation. These changes are evident across both the traditional ‘supply’ and ‘demand’ sides of the electricity market – and concurrently – with current and forecast retirement of conventional thermal generation as it reaches the end of its economic life, growing investment in grid-scale wind and solar generation, and a rapid uptake and increasing penetration of rooftop solar photovoltaic (PV) panels at household level.

The rate at which these changes are occurring, and are forecast to continue, is shown in Figure 1. Figure 2 provides a forward projection of trends in the uptake of distributed energy resources, with even weak or neutral projections anticipating considerable growth between now and 2035. The drivers we see contributing to this changing power system are discussed below.

**Figure 1 NEM plant mix change, 2008 to 2017**

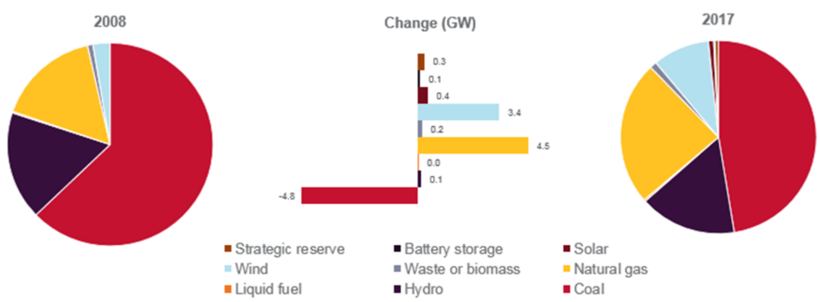
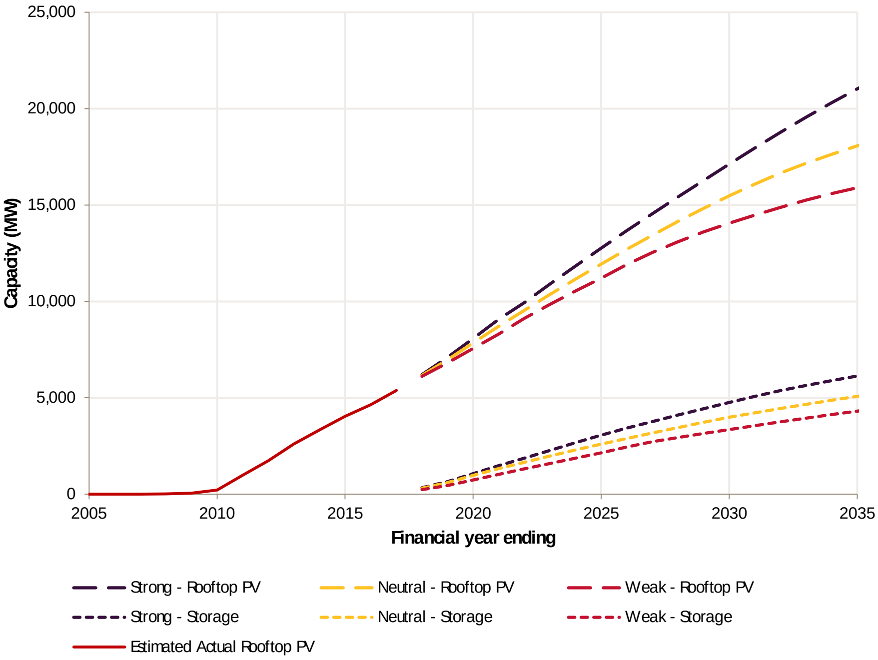


**Figure 2 Forecast trends in distributed energy resources**




### *Changing weather conditions*

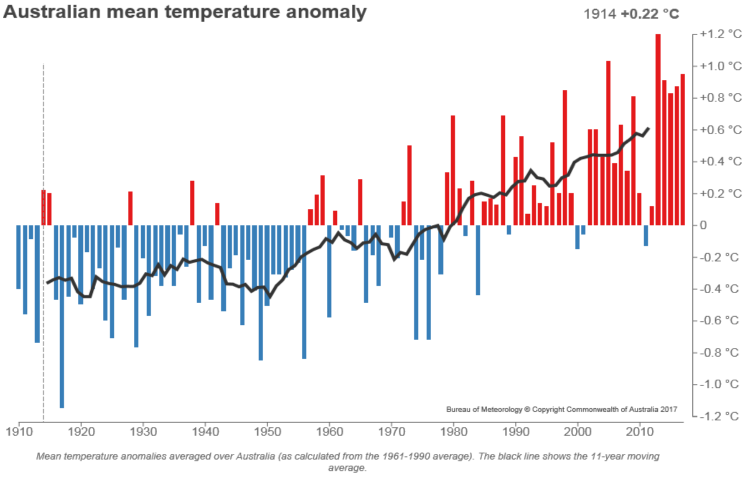
Weather has always had an influence on the operation of power systems. High demand days have been associated with cooling and heating needs, infrastructure is designed to withstand levels of extreme weather, and the capacity of networks to transmit power is related to contingencies and ambient temperature. So, the system is designed and operated with a view to the weather. What is different now is that:

- The climate is changing, in terms of temperature, and extremity and scale of weather events.
- Weather itself is now a major fuel source.

The Bureau of Meteorology has noted[3] that 2017 was Australia's third-warmest on record (see Figure 3 below, which also provides a visual representation of the trending upwards in Australia's mean temperatures over the period since climate records began in 1910). Australia's area-averaged mean temperature for 2017 was 0.95° Celsius (C) above the 1961-1990 average. Maximum temperatures were the second-warmest on record at 1.27°C above average, coming in behind +1.45°C in 2013. Minimum temperatures were 0.62°C above average, the 11th warmest on record.

[3] Australian Bureau of Meteorology. *Annual Climate Statement 2017*, available at http://www.bom.gov.au/climate/current/annual/aus/. Australian climate records commenced in 1910.

**Figure 3 Australian mean temperature anomaly**

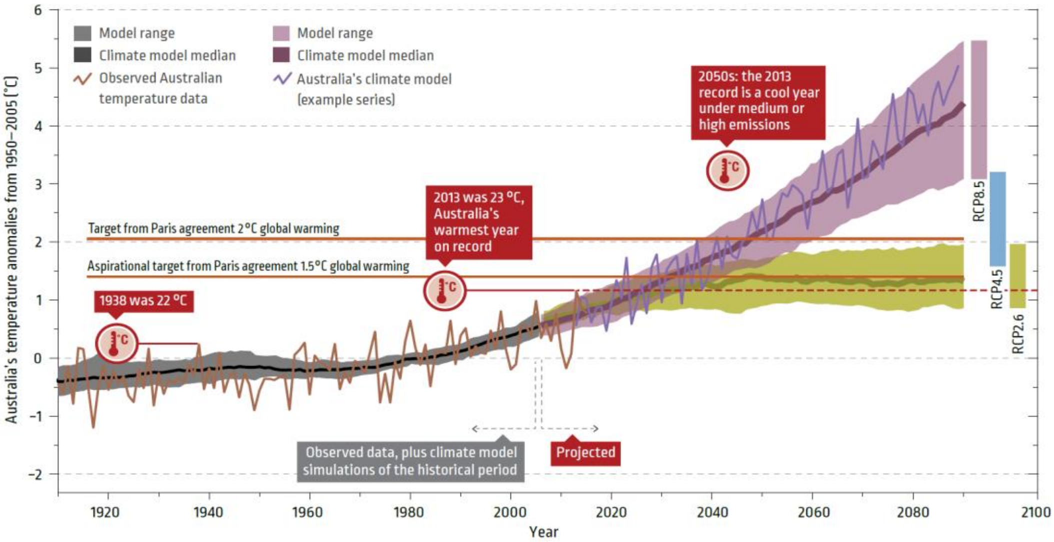



Source: Australian Bureau of Meteorology, *Annual Climate Statement 2017*.

Increasing temperatures and presence of prolonged heat events impact system reliability in several ways. These include increased challenges associated with managing coincident peaks (concurrent hot and humid days in multiple regions and across major cities in the NEM, particularly when combined with projected population growth and an increase in air-conditioning), the impact of prolonged heatwaves on grid resilience (where increased system stress can result in increases in individual plant failures, particularly in aging plants), and more broadly the increased risk associated with bushfires during these periods that impact system availability.

Further, increasing extreme temperatures from climate change and urban development means increased health and safety risks from non-supply during these events, compared to when the reliability standard was first established. As Figure 4 shows[4], back in 1998, temperatures as hot as experienced in 2013 had never been observed. The Bureau of Meteorology is projecting that 2013, while considered a hot year now, will only be an average year by 2030. In the next 10 years, the Bureau of Meteorology projects more frequent and hotter hot days.

**Figure 4 Australian mean annual surface warming in the past, and for future emissions pathways**




All these factors suggest the need for additional reserves in the system that can be made available during these predictable but rare combinations of circumstances. For instance, transmission outages arising as a result of bushfires can have a major impact on the resource mix available to affected regions. Demand

[4] Figure is from The Australian Climate Change Science Program's report, *Australia's changing climate*, 2016, available at https://www.climatechangeinaustralia.gov.au/media/ccia/2.1.6/cms_page_media/176/AUSTRALIAS_CHANGING_CLIMATE_1.pdf.

side solutions can enhance resilience in the face of major bulk system supply disruptions and reduce the need for major additional investments to cover extreme events. These factors further illustrate the benefits of a broader resource mix, better engaging price responsive demand as a viable resource to meet customer demand, and the potential to improve overall system efficient and energy price outcomes.

*Changing supply and demand curves*

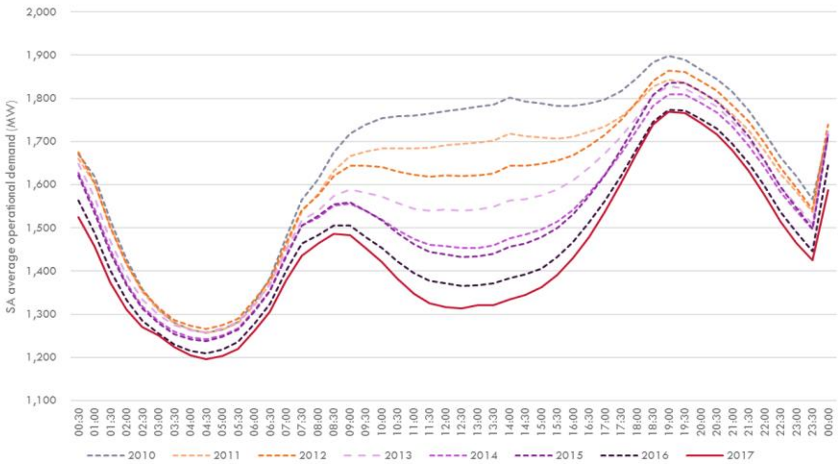
Rooftop solar has had a fundamental impact on usage and the system demand profile in recent years. As Figure 2 shows, the NEM has witnessed unprecedented growth of rooftop solar PV units – from approximately 14,000 units

in 2008 to 1,700,000 units (with an estimated output of 4,917 megawatts [MW]) in 2017. Currently, this resource sits behind the meter (on consumers' premises) and generates when it is sunny. It supplies the local load and exports the rest to the grid.

Rooftop solar is not visible to AEMO in real time, and cannot currently be controlled or coordinated. However, it can be seen on the grid as the well-known "duck curve" – namely, low demand in the middle of the day, with a larger ramp to the evening peak. This change impacts the demand profile, even on average demand days.

The effect of the changing curve can be clearly seen in Figure 5, which demonstrates the change AEMO is seeing in average operational demand, with significant variation in the shape of operational demand over the period from 2010-17 coinciding with the rapid uptake of solar PV resources over this period.

**Figure 5 Effect of growing rooftop solar**




Note: Figure 5 shows average operational demand in South Australia. These trends are emerging in other NEM regions and the Western Australian Wholesale Electricity Market (WEM).

Mid-day minimums are now expected in regions with significant levels of rooftop solar penetration, and new midday low consumption records are becoming common. For example, South Australia experienced its lowest operational demand since 2015, of 661 MW, at 13:30 on 2 October 2017. The highest demand that day was 1,409 MW at 20:00, already representing a large variation. Most of the variation that day was managed by generation in other regions, through the interconnector with Victoria.

Western Australia is also experiencing these changes, and all regions of the NEM should expect them as rooftop solar penetration increases.

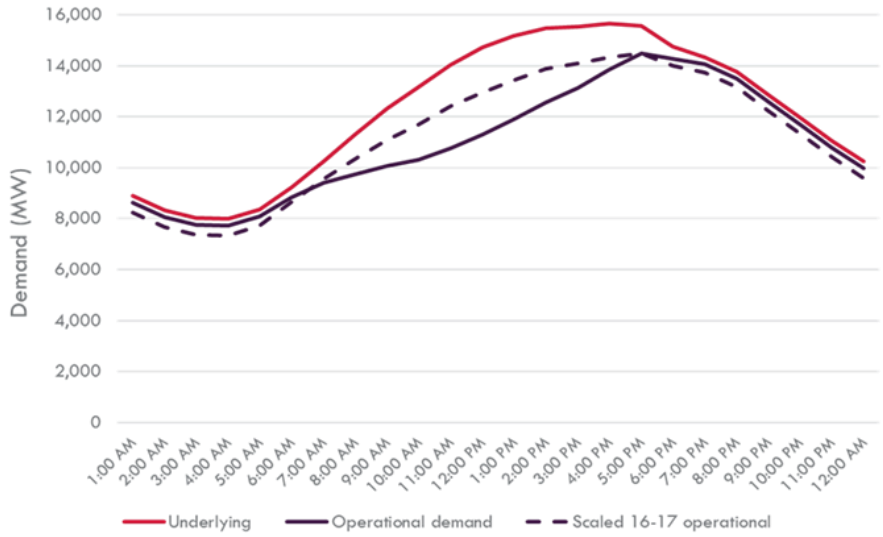
For AEMO, these low periods can create challenges for maintaining minimum levels of generation available to respond to load changes and at some levels may cause voltage changes.

Analysis undertaken by AEMO further shows it is possible to have sufficient resources to meet the NEM reliability standard while simultaneously having a high risk of insufficient supply to meet demand under more extreme, but still plausible, future conditions. The changing demand profile is contributing to this growing difference in the expected level of unserved energy (USE) and exposure to potential supply shortfalls at times of peak demand[5].

[5] Unserved energy (USE) means energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply), because there is not enough generation capacity, demand side participation, or network capability, to meet demand. The planning reliability standard, as defined in the Rules (clause 3.9.3C), is a maximum expected USE in a region of 0.002% of the total energy demanded in that region for a given financial year. This is discussed further in Appendix A3.

The installation of high levels of embedded solar PV generation across the NEM is leading to a later and shorter peak in the ‘operational demand’ or net demand on the system. Figure 6 shows this effect.

**Figure 6 Changing load shape is resulting in a shorter and later operational demand peak**




Because the USE reliability standard is an annual statistical forecast, the actual occurrence of load shedding in a given year over a particular combination of weather events could be much higher than the expected level. As a specific example, temperatures of 40°C or higher in Sydney could be the catalyst for extreme 1-in-10 year electricity demand conditions, particularly when these temperatures are experienced towards the end of the day when business demand is still relatively high, residential demand is increasing, and rooftop solar generation is declining.

The value of customer reliability during a severe and widespread outage is likely to be higher than at other times. Further, increasing extreme temperatures from climate change and urban population growth and development means increased health and safety risks from non-supply during these events compared to when the reliability standard was first established.

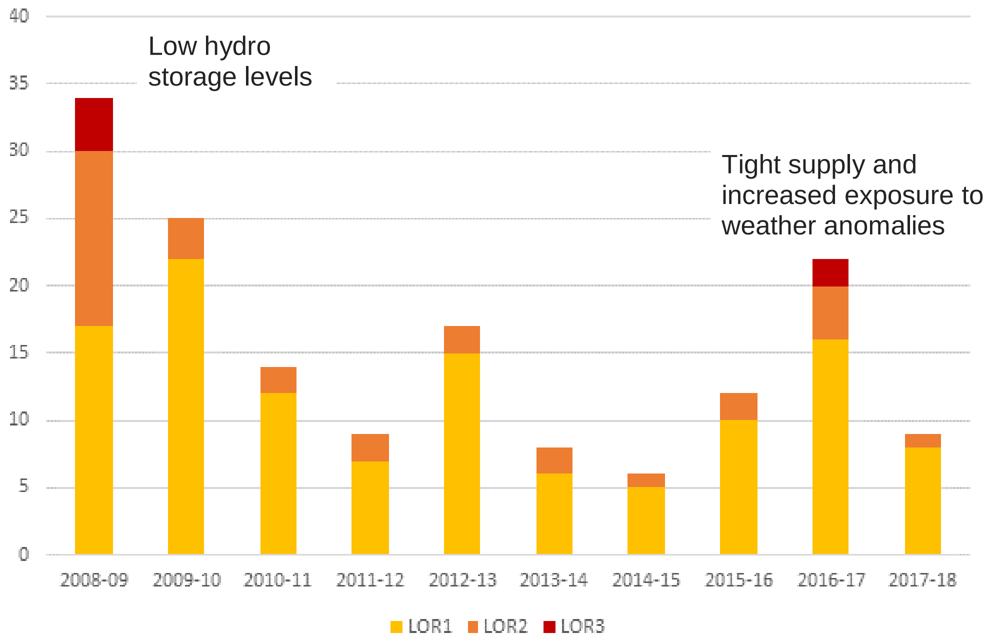
An increasingly “peaky” system demand will require resources that respond quickly and for relatively short duration.

### *Reserve management and market interventions*

Examination of historical Lack of Reserve (LOR) conditions also highlights the increasing influence of weather on the power system – both as a fuel source, and through climate change. While demand peaks have always been uncertain, and likely to vary according to the weather, the power system must now also manage increased uncertainty and variability of supply. LOR notices are issued by AEMO to indicate to market participants a tightening in available supply reserves, with notices increasing from LOR1 to LOR3 to give clear signals that the system is approaching closer to a point where AEMO, as operator, would need to shed load to avoid system loss.

In Figure 7 below, the number of LOR notices issued by AEMO over the past decade indicates an increase in the incidence of LOR2 and LOR3 conditions being observed, consistent with the tighter supplies and increased exposure to weather anomalies over this period.

**Figure 7 History of LOR notices, 2008-09 to 2017-18 (year to date)**




Note: This figure uses the history of Market Notices of LORs being issued, which is similar to how the Australian Energy Market Commission (AEMC) has counted LORs in reporting market performance. The count does not exactly match the number of times LOR conditions have existed, but it shows the same trend and also enables us to go as far back as 2008-09.

Consistent with the changing resource mix, and challenges associated with predictability of resources on the system, AEMO needed to procure greater volumes of strategic reserves in the lead up to summer 2017-18. AEMO entered into agreements with large electricity users, retailers, and generators to secure a total of 1,150 MW of strategic reserves across Victoria and South Australia that we can call on through the Reliability and Emergency Reserve Trader (RERT) process[6] in emergencies, such as multi-day heatwave events occurring concurrently across both South Australia and Victoria. The use of RERT over summer 2017-18 was only the fourth time AEMO (and its predecessors) have needed to contract for this mechanism over the past two decades, the last time being in 2014.

As the generation mix changes, it is becoming more challenging to maintain the security and reliability of the power grid. AEMO has found it increasingly necessary to both impose constraints on generation and use our directions powers to maintain system security and a reliable operating state.

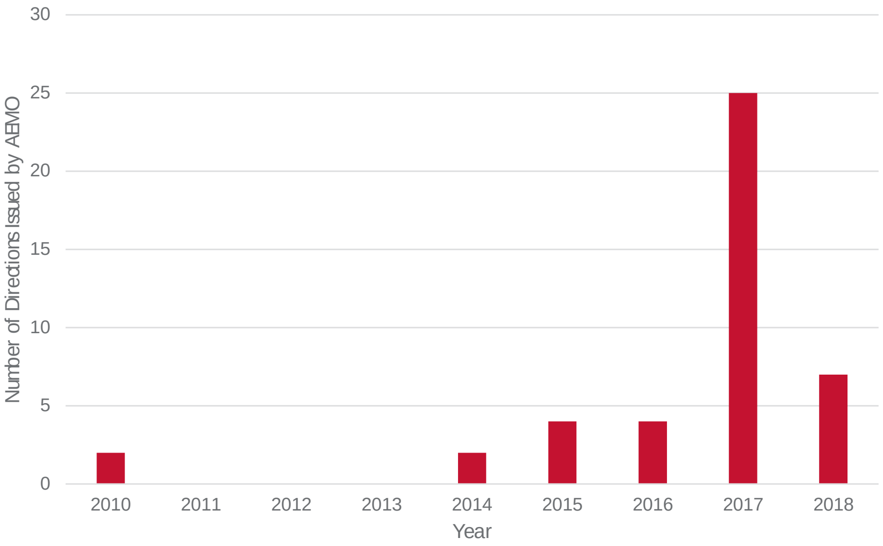
For example, the high proportion of non-synchronous generation in South Australia means AEMO is often intervening to maintain a balance between synchronous and non-synchronous generation. Using powers of direction to meet the need for a level of conventional plant in these circumstances is necessary but undesirable. It generally leads to higher costs to customers through intervention pricing and the payment of compensation.

With time and further devolution of the system in a disorderly way, these inefficiencies will continue to grow. While system strength requirements are currently the most binding, in many cases, if AEMO was not intervening to maintain system strength, we would still have to intervene via the use of constraints rather than directions to address other technical requirements, such as maintaining minimum amount of inertia in NEM regions that may be subject to islanding.

Figure 8 illustrates the number of directions (mandatory instructions made by AEMO to generators and network service providers (NSPs) for system security purposes) issued in the NEM in recent years.

[6] The RERT is a function available to AEMO to maintain power system reliability and system security using reserve contracts. It is termed 'off-market' as the generation or demand response sits outside the wholesale electricity market.

**Figure 8  Number of AEMO directions in the NEM since 2010**




Note: 2018 is for a partial year, 1 January - 5 February 2018.

The same resources can often supply a number of essential services to support both security and reliability. An efficient approach to market design would seek to co-optimise investment in and deployment of resources to meet these needs.

*Meeting consumer expectations*

The concurrence of all these drivers in the operating environment, with resulting impacts on market outcomes, are creating a highly challenging time for energy customers across the NEM. Consumer confidence in the energy market is at an all-time low nationally, with falls in every state and territory, and consumer confidence that the overall market is working in their interests averaging 21% nationally[7]. At the same time, community interest in relation to the energy market outcomes and management of reliability is at an all-time high.

As market operator, our ultimate objective is to operate efficiently to support affordability for Australian consumers, while delivering power system security and reliability, and meeting our emission reduction commitments.

Fortunately, many of the same changes in technology and resources that are creating challenges for system operations can also become solutions, if approaches to the market and regulatory conventions are re-calibrated to address the changed conditions. Specifically, the advent of advanced intelligence in the networks, and increased levels of distributed energy resource investment that supports more elastic and flexible price responsive demand, can become an asset for supporting reliability in a more efficient manner if they can be relied upon by AEMO.

As system operator, AEMO must use pre-determined involuntary load reductions to keep the system intact during periods where the supply is inadequate to safely meet demand. Failure to strategically shed load during these periods will risk blackouts and greater consumer disruption. However, involuntary loss of service typically is not a publicly acceptable outcome, and is, in and of itself, an extreme measure. During periods of hot temperatures, involuntary loss of power poses significant risk of harm to public health and safety. Also, as the overall economy becomes more digitised and power-dependent, even short-term losses of the system can have substantial adverse economic effects. Frequent and regular outages can also cause business consumers to leave the system to achieve higher reliability, which can have negative economic consequences on the overall economy of the system.

Historically, our only choice to avoid involuntary load reductions during peak periods or to address unplanned generation or system outages would be to construct new peaking generation, along with the transmission and distribution necessary to accommodate peak conditions. Now, with the increase in distributed energy resources and the capability of enabling price responsive demand as a resource on the system, properly designed wholesale markets can support allowing AEMO to rely on voluntary and price

[7] Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2017, available at http://energyconsumersaustralia.com.au/publication/energy-consumer-sentiment-survey-findings-december-2017/.

responsive load reductions and shaping to achieve higher degrees of reliability using embedded assets in the system.

This capability, along with additional diversity of supply supported with increases in interconnector capability, will naturally increase competition in the markets and, with increasing system reliability and security, will support more economically efficient system-wide asset utilisation. The net outcome of a well-designed two-way market can create significant consumer benefits – a more efficient, reliable, and secure system at a total lower cost at the meter.

### Adapting market design to meet changing power system needs

As the market and system operator, AEMO's objective is to rely on the markets to support the operation of a secure, reliable, and cost-efficient power system. The power system operating requirements are of paramount importance and should be the starting point for the reliability framework of the NEM.

Power markets do not exist in the abstract. Power markets are a vehicle for meeting the needs of a highly complex and integrated power system. For any regulatory or market design to achieve value for consumers, the starting point must be an understanding of the existing and evolving needs of the system. Markets need to clearly value the services and system needs, to promote the appropriate investment and operational outcomes desired.

The key issue is whether a market designed principally around real-time spot energy markets and bilateral contracts is sufficient, now and in the future, to achieve optimal economic outcomes for consumers and investors.

Based on recent experience operating the markets, AEMO believes this is no longer the case and appropriate adjustments must be made. This view is based on key changes we are observing in the market. These key changes are summarised here and discussed in more detail in this report.

A. *Price formation and payment for flexibility and availability*.

   The current market design relies on contract obligations and price scarcity to incentivise generators to bid into the spot market. This market design presumes that generators will naturally bid in to avoid contract risk. However, this contract risk only occurs when the generator perceives prices will be higher in the market than its contract price.

   Due to the increase in zero marginal cost renewable resources, both in front of and behind the meter, traditional dispatchable generators will not bid in if they perceive that prices will be low or negative due to the presence of these sources of supply. In many hours of the day, the potential forecast presence of these renewable resources is keeping the spot price low. Dispatchable generators that have higher short-term marginal costs than the market prices will rationally not bid during these periods for fear of driving prices even lower. Yet, due to weather and resource variability, it is during these periods that AEMO relies on these resources to manage unpredictable supply requirements.

   In effect, the single price for energy no longer accurately prices the value of these essential capabilities, thereby necessitating some level of unbundling and payment for performance to avoid spot price distortion.

   AEMO's only available tool for this now is market intervention, which we are increasingly required to use to manage reliability and security risk. AEMO considers this a sub-optimal result. We believe that once the market is aware of and can be paid for these availability and reliability services, the market will offer in resources that are more diverse and provide to customers the benefits of competition and innovation. Chapter 3 of this paper discusses market design options.

B. *Changed load profile and ramping requirements.*

   The increased presence of rooftop solar is having a significant impact on the load profile in parts of the NEM today, and that will only increase. It has the impact of creating very low loads, at accompanying low prices, when solar output is highest, and a very high and fast ramp in the afternoon. As noted, in the industry this is known as the "duck curve".

   To maintain system reliability at an efficient price, the full range of resources available need to be valued for the characteristics they can bring to the market. The current arrangements do not fully optimise the value that could be delivered by some resources, particularly price-responsive demand and fast responding storage. To deliver improved market outcomes, flexible resources should, for example, be rewarded for their ability to shift demand to the low load periods and to follow the ramp more effectively and efficiently.

The current market design does not support these capabilities, and no single participant has sufficient system-wide situational awareness which AEMO, through a well-designed market, could provide to value this capability.

C. *Resource diversity and economic optimisation.*

Supply and demand resources in the NEM are much more diverse than when the market commenced, and this change will continue.

The NEM was designed around conventional large-scale central supply resources, and has worked well to allow these resources to self-commit and optimise economic results. The NEM now needs to operate with more individual and diverse types of resources, which, in addition to having a very different cost profile, have different time periods in which decisions must be made to support efficient outcomes. Improved price signals and changes in commitment obligation have the opportunity to reduce barriers of entry for new resources and improve AEMO's ability to optimally dispatch the resources for economic and system efficiency.

For example, demand and storage resources that can support improved load profiles, as well as resources that require fuel purchase commitments, have improved opportunity to commit if they can commit prior to the day of the dispatch interval. Most spot markets throughout the world have some form of day-ahead commitment by individual participants, which supports greater supply diversity and co-optimisation across the resource fleet.

*D. Investment requirements – market design also impacts investment decisions.*

Unless essential services for reliability and security are accurately valued and priced in the market, the signal that supports investment in these resources is impaired. The consequences of this are harmful to the future of the market. Investments in resources that support the need to maintain supply reliability will alternatively lead to further vertical integration where individual companies will build only to meet their more certain mass market demand, or will depend on government intervention.

We see that occurring today in the NEM. The National Energy Guarantee (the Guarantee) will help solve this challenge, but (as the Energy Security Board (ESB) similarly observes in the Guarantee consultation paper[8]) absent more modern design in the spot markets, the Guarantee will only be able to offer a partial answer.

The changing dynamics present both challenges and opportunities to the market, and to AEMO itself in carrying out our role as independent system and market operator. These changes have implications for reliability, security, and ultimately the prices being paid by customers.

Based on the changes we see in the system, AEMO is concerned that the current market design is not sufficiently valuing resource characteristics of flexibility and dispatchability, and that, in the absence of a market design change, sufficient investments in new resources or existing resources that provide dispatchable capability are unlikely to occur. We note our observations are consistent with similar findings in the Finkel Review.

With a higher degree of variability in output and reduced predictability in the resource mix, AEMO is needing to intervene in the market on an increasing basis to maintain system security and reliability. Although measures taken
are necessary, and it is within AEMO's remit to take such action, these interventions will deliver sub-optimal outcomes for customers.

In this changing context, AEMO considers that a more encompassing and holistic view of the needs of the future framework should be taken, and would like to work with ESB colleagues and stakeholders to carefully consider the following suite of potential reforms:

- An operational reliability standard, beyond the existing reliability standard, which factors in a level of reserve to manage power system reliability during extreme conditions. In real time, sufficient operational reserves need to be available from flexible, dispatchable resources to respond to variable resources, changes in consumer demand, and plant contingencies.
- The power system also operating with strategic reserves that sit outside the market (which respond quickly and are available when we need them) should a gap in supply and demand arise. These reserves should be procured in the most efficient manner possible to reduce costs to consumers.

[8] The ESB consultation paper on the National Energy Guarantee is available at http://www.coagenergycouncil.gov.au/publications/energy-security-board-national-energy-guarantee-consultation-paper.

- Improved mechanisms to value and pay for reliability and flexibility.

The areas of reform that AEMO believes should be pursued holistically also formed similar recommendation in the Finkel Review adopted by the COAG Energy Council. AEMO looks forward to working with ESB colleagues and stakeholders to develop the additions to the current market arrangements to ensure consumer demands for reliable, secure and affordable power are addressed.

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# 1. A changing power system

Operation of the power system to deliver electricity to consumers is the outcome of a complex integrated system of independent systems, which must be highly coordinated. The power system can function well only when operated within certain physical parameters that adhere to particular engineering principles.

Central to efficient real-time power system operation is the process of security-constrained economic dispatch, where resources are continually co-optimised to meet consumer needs at the lowest cost while keeping a broad range of power system parameters within tight technical limits. The fundamentals of this process are the same, regardless of whether a competitive market is in place or not.

In the transforming power system, while the engineering principles are the same, the complexity of achieving them
is radically different. In the last decade, the National Electricity Market (NEM) has changed from a system with a
high level of grid-scale, synchronous generation with sufficient supply and reserves, to one that includes both synchronous and non-synchronous plant, diverse sources of supply (including storage), consumer-based resources
that can supply critical system functions, and the capability to use data and information in ways that were inconceivable in prior periods.

The scale and speed of the change in Australia is noteworthy, particularly given our system is one of the world's largest geographically, yet relatively small electrically. Australia is not alone, however, in experiencing these phenomena. Power systems and power markets throughout the world are reviewing and adapting their approaches to gain maximum advantage from these resources to achieve desired economic and reliability outcomes, while also pursuing jurisdictional environmental goals.

The attributes required for modern markets with high degrees of variable and diverse energy resources include greater visibility, flexibility, and speed to manage expected and unexpected variations in supply and demand, as well as other essential system services, such as system strength, frequency control, and voltage control.

In this chapter we discuss the fundamental transformational changes currently occurring and impacting operations in the NEM both now and in the future, being the:

1. Changing supply mix.
2. Changes occurring in electricity use.
3. Influence that changing weather conditions and climate are having on the power system.

## 1.1 The changing supply side

In this section we explore:

- Changes in the generation mix over the last 10 years.
- Expected retirements of the aging coal generation fleet.
- How the changing economics are expected to influence future investment.

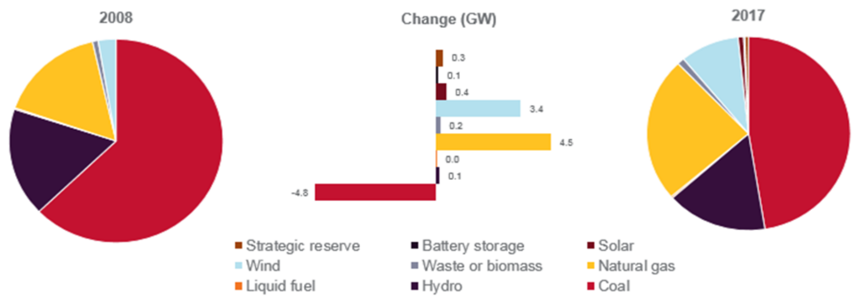
- The investment that has been foreshadowed to date through committed and proposed projects.

Throughout the early 2000s, there was relatively strong investment in grid-scale dispatchable generation. Dispatchable generation is generation whose output can be relied upon to follow a target at some time in the future. This includes conventional large-scale generation (using coal, gas, liquid fuels, and hydro), while wind and solar generation in operation in the NEM is not fully dispatchable[9].

The NEM is now facing an unprecedented replacement of its generation fleet. Evidence of this radical transformation can be seen in the change in the portfolio of supply resources in the NEM over the last decade, with a shift away from coal generation to natural gas and wind as fuel sources.

More specifically, 5,199 megawatts (MW) of baseload generation has retired in the past ten years. Over the same time period, these resources have been replaced with 2,895 MW of gas-powered generation (GPG), 273 MW of hydro, 91 MW of liquid fuel, 2,965 MW of wind, 265 MW of grid-scale solar, and 186 MW of other sources of generation, such as biomass. Since 2014, new supply resources have been predominantly renewables. Figure 9 shows the change in the past decade.

**Figure 9 NEM plant mix change, 2008 to 2017**



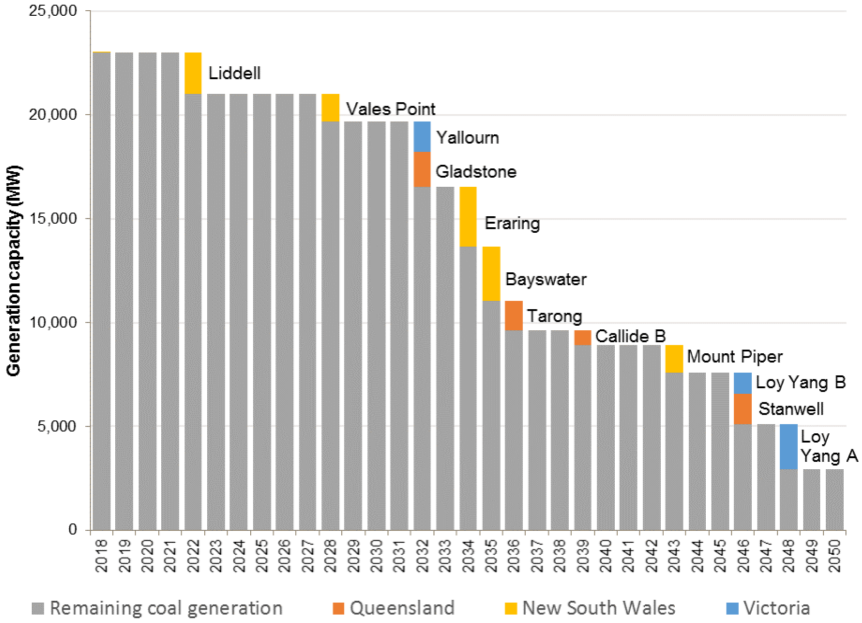

Changes to the supply side will continue. With the March 2017 retirement of Hazelwood Power Station, 1,600 MW of dispatchable generation was removed from the NEM. Approximately 1,800 MW of further operating capacity (Liddell) has been announced as intending to withdraw over the coming five years.

When all the aging coal generation fleet is considered, approximately 16 gigawatts (GW) of capacity is expected to leave the NEM by 2050 and will need to be replaced in some form. The expected retirement of the coal generation fleet is shown in Figure 10 below[10].

[9] For more information on dispatchability and other power system requirements, see AEMO's *Power System Requirements* paper, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

[10] Australian Energy Council. *Submission to the Parliamentary Enquiry, Retirement of coal fired power stations*, 2016, available at https://www.aph.gov.au/parliamentary_business/committees/senate/environment_and_communications/coal_fired_power_stations/submissions.

**Figure 10** NEM coal generation fleet if plant retires as announced or at 50th year from full operation




Older baseload units find it increasingly difficult to compete in the current environment. These units have historically relied on relatively constant high production levels and stable revenues. In general, they are not well suited to respond to rapidly varying energy system needs. Their business model will be further challenged by increasing variability in the system and falling costs of competitive sources of energy, which in turn could lead to earlier than expected retirement. Further to this, the economics for investment are also changing. Investment in generating plant in energy-only markets depends on wholesale prices responding to reserve scarcity and exceeding new entrant costs. This is backed up by contract markets that reflect these underlying prices, but provide a stable revenue resource.

There is evidence from the last few years that the connection between reducing reserves, increasing wholesale spot prices, and additional supply is not being borne out in the NEM. The costs of variable renewable energy (VRE) and storage have fallen at an unprecedented rate and continue to fall. The business case for these assets relative to conventional generation continues to grow stronger, due to the combination of these cost decreases, relative risk profile, consumer preference, and government support.

AEMO analysis (discussed in more detail in Appendix 1) reveals that:

- There is a disconnection between low reserves and prices. Figure 11 illustrates that many price spikes in South Australia have occurred during non-scarce conditions, while price spikes in Victoria have been more in line with scarce conditions, particularly this summer (there were no price spikes at that level in Victoria in 2017).
- Despite record high wholesale price increases, current and projected prices and volatility do not provide sufficient financial incentive for new dispatchable plant. Figure 12 shows the continued reduction in the business case for new build dispatchable gas plant. As wholesale market price projections are critical for asset valuations, prospective investors are unlikely to build new dispatchable plant under current and forecast market conditions, nor to invest in upgrading existing plant, absent certainty of a forward price commitment.
- There has been a drop in overall liquidity in the contract markets. Figure 13 shows that AEMO’s analysis of available ASX Energy futures data includes a material drop in overall liquidity (volume traded multiplied by megawatt hours (MWh)) of both swap and cap products traded since 2014 (-25% and -19% respectively).
  - In South Australia, swaps and caps have fallen 61% and 62% respectively (see Figure 39 in Appendix A1.3, left hand side).
  - New South Wales has also seen a large reduction in ASX swap and cap liquidity, down 50% and 21% respectively (see Figure 39 right hand side).
  - Swap liquidity in Queensland fell 19% and cap liquidity remained stable (rising 1%).

– Swap liquidity in Victoria rose 6%, while cap liquidity fell 34%.

**Figure 11 Incidence of price spikes during lack of reserve (LOR) and non-LOR conditions**

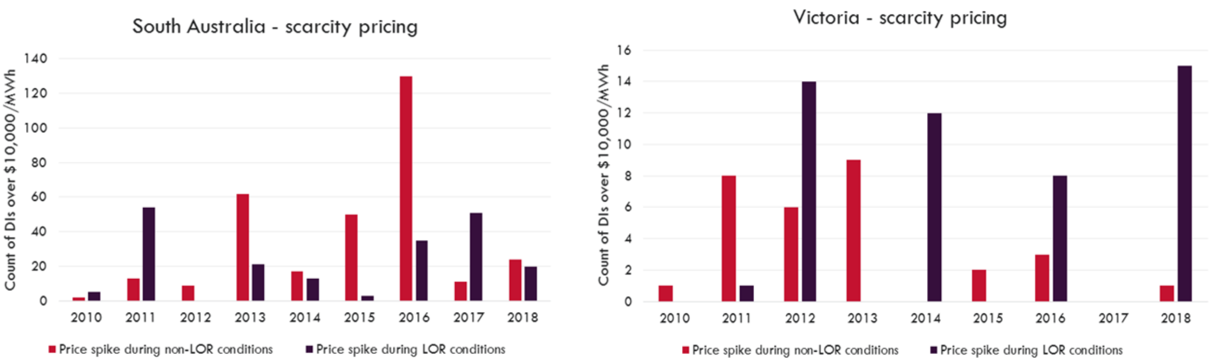



**Figure 12 Comparison between the levelised cost of electricity (LCOE) of new build open-cycle gas turbine (OCGT) and closed-cycle gas turbine (CCGT), and forward price curves**

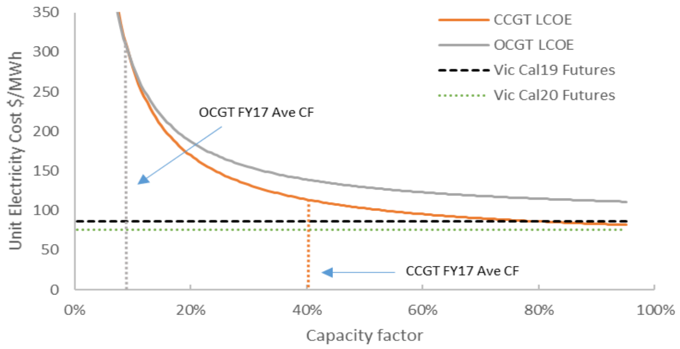
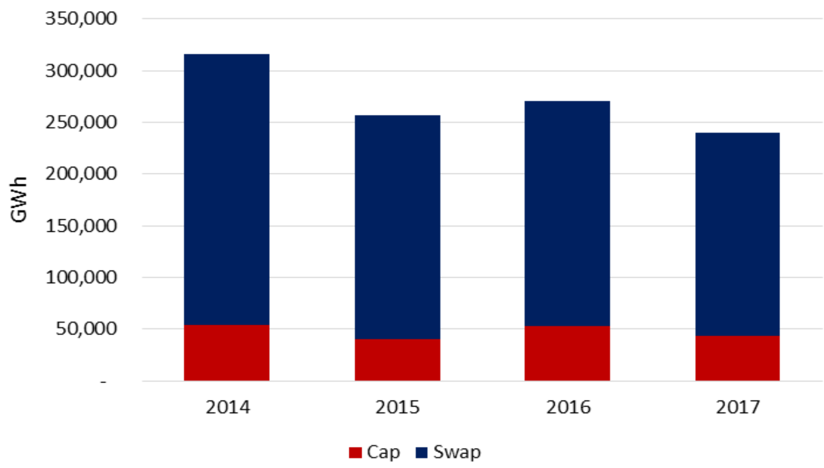



**Figure 13 Traded futures volumes by product in the NEM since 2014**

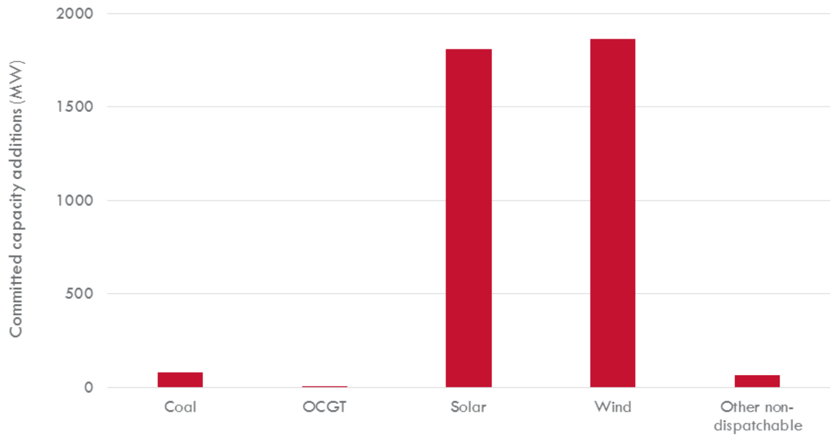



Note: ASX is the source for underlying data.

The analysis AEMO has undertaken is supported by the information we collect from participants relating to the capacity of existing, withdrawn, committed, and proposed generation projects in the NEM.

Figure 14 below provides details of the currently committed changes to generation capacity in the NEM[11]. This
shows that VRE makes up the majority (96%) of new committed capacity builds. As at December 2017, 3.7 GW
of non-dispatchable capacity (large-scale wind and solar) has been committed in the NEM, while only 0.09 GW of dispatchable capacity has been committed.

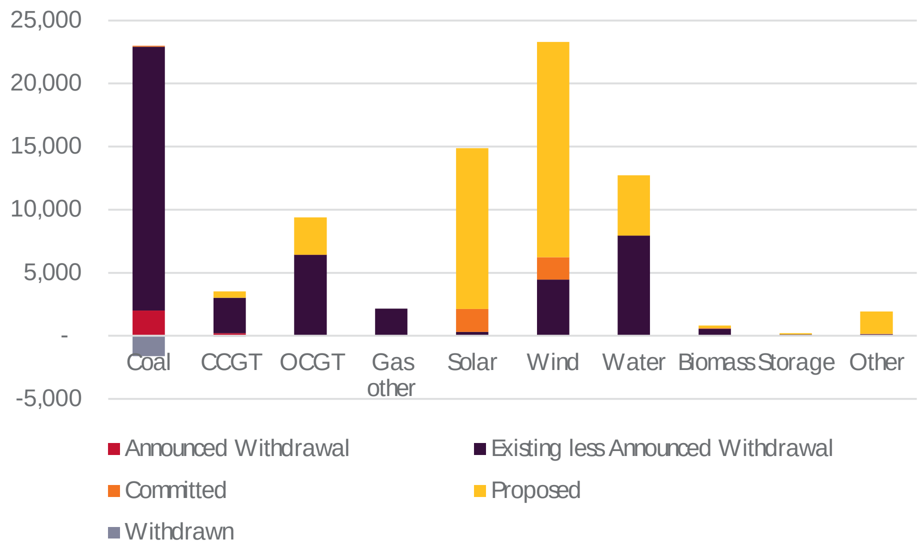
**Figure 14 Committed changes in generating capacity in the NEM**




Looking beyond committed developments, a number of announced projects do add some dispatchability to VRE by adding a level of local storage (typically a small proportion of the VRE capacity). There is also substantial interest in pumped hydro storage projects.

Figure 15 and Table 2 below summarise all NEM installed capacity at 4 January 2018, including committed and proposed projects. While it is expected that only some of the proposed projects will be completed, it does
indicate the vast majority of proposed projects are solar and wind and this category includes only limited dispatchable resources.

**Figure 15 Existing, committed, and proposed generation in the NEM at 4 January 2018**




[11] For details of generation in each category, as advised by generators, see AEMO's Generation Information webpage at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. A definition of the criteria for committed projects is in each regional information spreadsheet on this page, on the "Background information" tab.

**Table 2 Existing, committed, and proposed generation in the NEM at 4 January 2018**

| Status | Coal | Gas CCGT | Gas OCGT | Gas other | Solar* | Wind | Water | Biomass | Storage | Other | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing** | 22,916 | 3,013 | 6,434 | 2,159 | 323 | 4,462 | 7,941 | 579 | 100 | 142 | 48,070 |
| Announced withdrawal | 2,000 | 208 | 34 | 30 | - | - | - | - | - | - | 2,272 |
| Existing less announced withdrawal | 20,916 | 2,805 | 6,400 | 2,129 | 323 | 4,462 | 7,941 | 579 | 100 | 142 | 5,798 |
| Committed | 78 | - | 4 | - | 1,812 | 1,776 | 4 | 31 | 2 | 29 | 3,737 |
| Proposed | - | 500 | 2,950 | - | 12,735 | 17,047 | 4,784 | 214 | 110 | 1,758 | 40,098 |
| Withdrawn | -1,600 | -62 | - | - | - | - | - | - | - | - | -1,662 |

* Excludes rooftop photovoltaic (PV) installations.

** Existing capacity includes generation announced to withdraw but still operating.

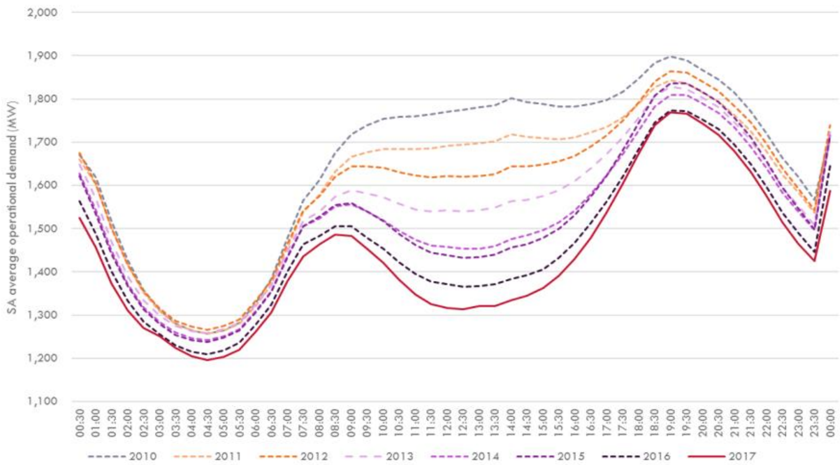
## 1.2 The changing demand profile

Rooftop solar photovoltaic (PV) has had a fundamental impact on usage and the system demand profile in recent years. The NEM has witnessed unprecedented growth of rooftop solar PV units – from approximately 14,000 units in 2008 to 1,700,000 units (estimated output of 4,917 MW) in 2017. Currently, this resource sits behind the meter (on consumers' premises) and generates when it is sunny. It supplies the local load and exports the rest to the grid.

Rooftop solar is not visible to AEMO in real time, and cannot currently be controlled or coordinated. However, it can be seen on the grid as the well-known "duck curve" – namely, low demand in the middle of the day, with a larger ramp to the evening peak. This change impacts the demand profile, even on average demand days.

The effect of the changing curve can be clearly seen in Figure 16. This demonstrates the change AEMO is seeing in average operational demand, with significant variation in the shape of operational demand over the period from 2010-17, coinciding with the rapid uptake of solar PV resources over this period.

**Figure 16 Effect of growing rooftop solar**

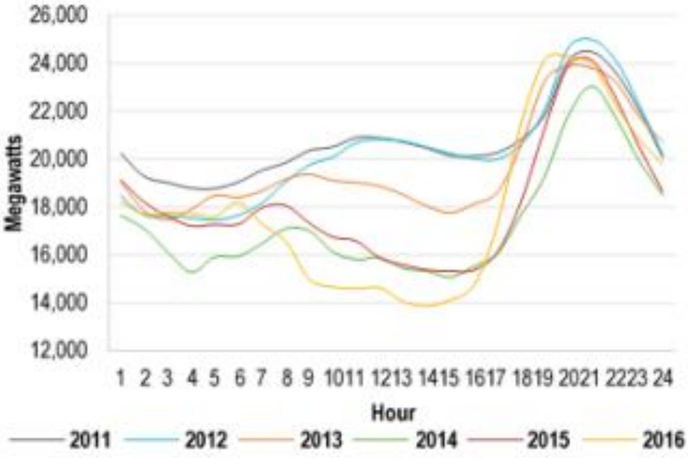



Note: Figure 16 shows average operational demand in South Australia. These trends are emerging in other NEM regions and the Western Australian Wholesale Electricity Market (WEM).

The recent high temperatures experienced in Queensland during the week commencing 12 February 2018 provided further evidence of the duck curve. On 12 February 2018, the scheduled peak demand of 9,550 MW occurred at 18:50, which was much later in the day than previous peak records.

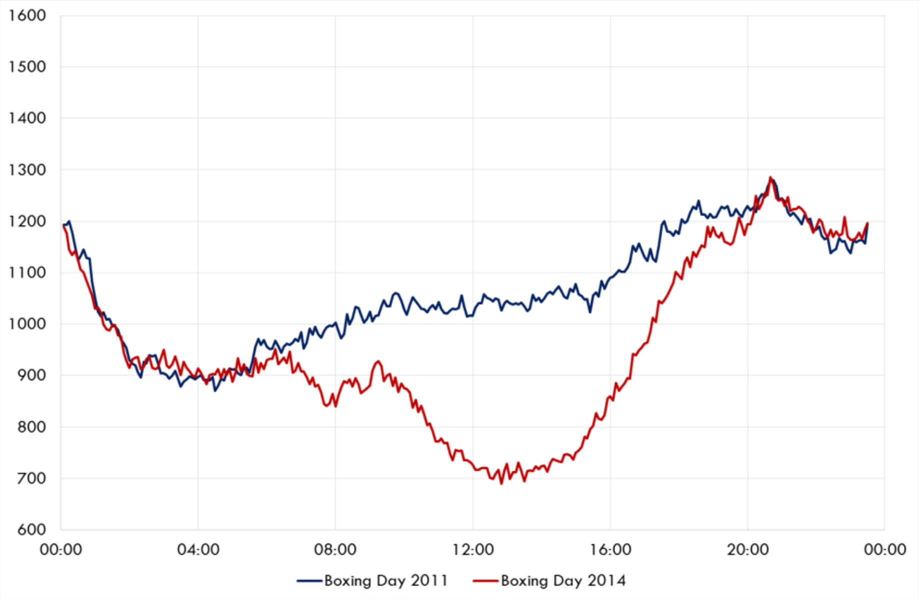
This phenomenon is not confined to Australia. For instance, recent experience in California, shown in Figure 17 below[12], also demonstrates this change.

**Figure 17 California lowest March daytime net load, 2011-16**




The effect of rooftop solar is even more pronounced on low demand days. An example of a low grid demand day is Boxing Day. Comparing the demand profile on Boxing Day 2014 against that on Boxing Day 2011, Figure 18 shows that the lowest demand of the day, which has conventionally been seen in the early morning, occurred in the middle of the day in 2014, at a time of maximum behind-the-meter solar generation.

**Figure 18 Changing demand profile – South Australia, Boxing Day 2011 vs 2014**




Mid-day minimums are now not uncommon in South Australia, and are setting record lows. South Australia experienced its lowest operational demand since 2015, of 661 MW, at 13:30 on 2 October 2017. The highest demand that day was 1,409 MW at 20:00, already representing a large variation. Most of the variation that day was managed by generation in other regions, through the interconnector with Victoria. An increasingly "peaky" system demand will require resources that respond quickly and for relatively short duration.

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[12] Figure sourced from Scott Madden, *Revisiting the California Duck Curve: an exploration of its existence, impact, and migration potential*, October 2016, available at http://www.scottmadden.com/wp-content/uploads/2016/10/Revisiting-the-Duck-Curve_Article.pdf.

With increased uptake of rooftop solar panels and home batteries in Australia and overseas, the costs will continue to decrease. This, combined with new technologies, is forecast to increase the level of distributed energy resources (DER) into the NEM. This is expected to further change the load profile and impact new and existing investments. As discussed in Chapters 2 and 3, the opportunity exists to use these investments to support greater competitive diversity, flexibility, and value of the NEM, but this will require changes in the current market design.

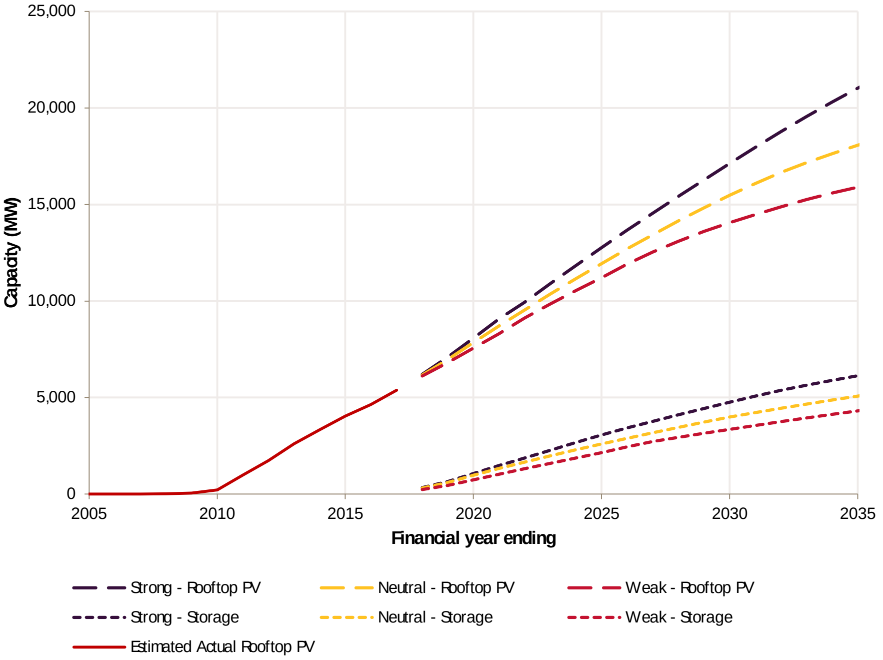
Further, consumer behaviour, with growing prosumer interest, is impacting on electricity use and demand profiles at
a wholesale level. Emerging technologies can now allow consumers to take a more active involvement in how their energy will be managed beyond the installation of rooftop solar panels, such as the use of home energy
management systems.

Other factors that also impact the load profile, and which AEMO has discussed in our electricity forecasting[13], include:

- Increasing air-conditioning load. While the new record demand experienced in Queensland in the week commencing 12 February 2018 is yet to be investigated, it is expected that the cheaper cost associated with installing air-conditioning units, and increased numbers of these units, contributed to the maximum demand.
- Reduced manufacturing load.

Against a backdrop of projected scenarios, where some scenarios Identify between 30% and 45% of all energy
will come from DER by 2050, it is clear that the impact of trends will continue to grow. This can be seen in Figure 19 below[14].

**Figure 19 Forecast trends in distributed energy resources**




These changes in the load profile result in an economic and operating challenge for continuous baseload. This creates an increasing need for resources (generators or price responsive demand) to ramp up and down quickly. Mechanisms need to be put in place to ensure that efficiency across the supply mix is incentivised and able to meet demand across all timeframes.

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[13] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights.

[14] These DER forecasts were produced for AEMO's 2017 *Electricity Statement of Opportunities* (ESOO).

## 1.3 Weather and climate

Weather has always had an influence on the operation of power systems. High demand days have been associated with cooling and heating needs, infrastructure is designed to withstand levels of extreme weather, and the capacity of networks to transmit power is related to contingencies and ambient temperature. So the system is designed and operated with a view to the weather.

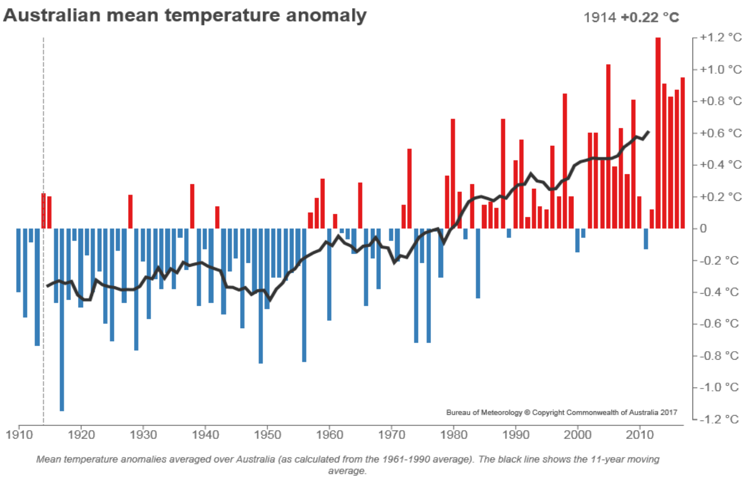
What is different now is that the:

- Climate is changing, both in terms of temperature extremity, size and duration of weather events.
- Weather itself is now a major fuel source.

The Bureau of Meteorology has noted[15] that:

- 2017 was Australia's third-warmest on record (see Figure 20).
- Australia's area-averaged mean temperature for 2017 was 0.95° Celsius (C) above the 1961-1990 average.
- Maximum temperatures were the second-warmest on record at 1.27°C above average, coming in behind +1.45°C in 2013. Minimum temperatures were 0.62°C above average, the 11th warmest on record.
- The 11-year mean temperature for 2007-17 was the highest on record, at 0.61°C above average.
- Seven of Australia's 10 warmest years have occurred since 2005, and Australia has experienced just one cooler than average year in the last decade (2011).
- Background warming associated with anthropogenic climate change has seen Australian annual mean temperature increase by approximately 1.1°C since 1910. Most of this warming has occurred since 1950.

**Figure 20 Australian mean temperature anomaly**




Source: Australian Bureau of Meteorology, *Annual Climate Statement 2017*.

Experiences across the summers of 2016-17 and 2017-18 have revealed a number of events where Lack of Reserve (LOR) conditions have been forecast. This is due to a combination of higher than average temperatures and limits in capacity or unplanned failure of generating plant. As the following chart from the Bureau of Meteorology shows, the number of days above the 99th percentile for each month, aggregated over the year, is growing. This indicates that the weather is changing and that more extreme peak temperatures and heatwaves are more likely.

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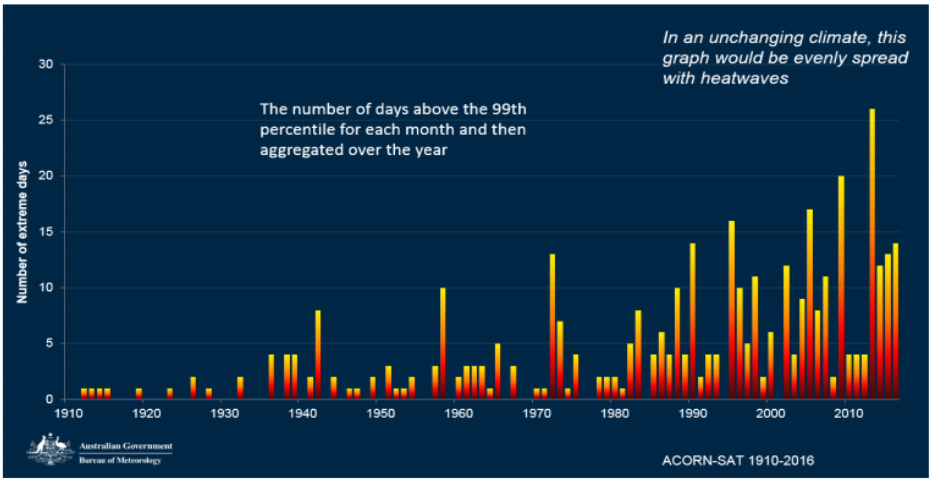
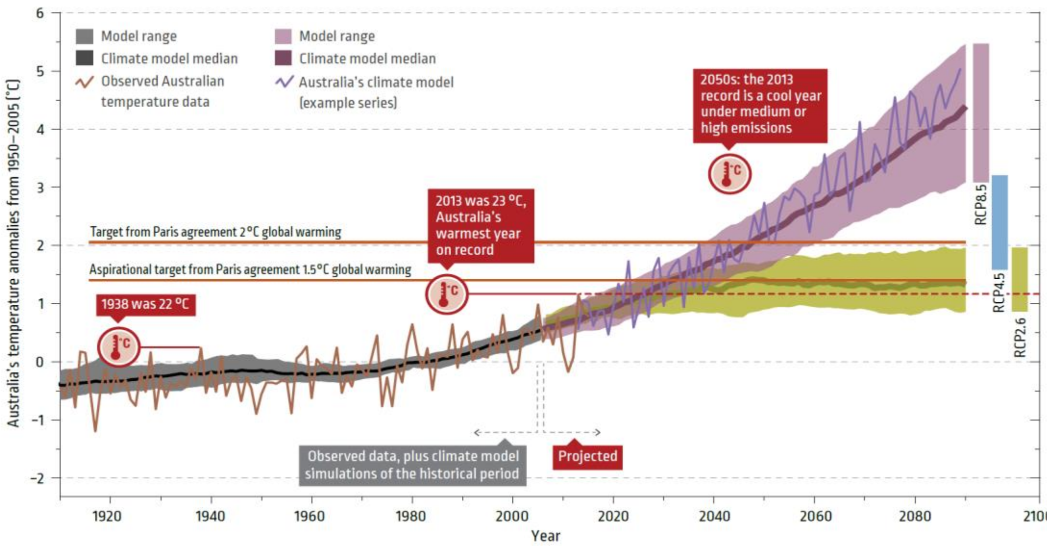
[15] Australian Bureau of Meteorology. *Annual Climate Statement 2017.* Available: http://www.bom.gov.au/climate/current/annual/aus/. Note, Australian climate records commenced in 1910.

**Figure 21 99th percentile for temperature by month**




As Figure 22 shows[16], back in 1998, temperatures as hot as experienced in 2013 had never been observed. The Bureau of Meteorology is projecting that 2013, while considered a hot year now, will only be an average year by 2030. In the next 10 years, the Bureau of Meteorology is projecting more frequent and hotter hot days.

**Figure 22 Australian mean annual surface warming in the past, and for future emissions pathways**




The increasing temperatures and presence of prolonged heat events impact short- and long-term system reliability in several ways:

- First, AEMO is concerned that increasing temperatures can lead to very hot and humid days in multiple regions of the NEM. These temperature increases, combined with population growth and increased air-conditioning, could result in historically high peaks in individual years.
- Second, prolonged heatwaves increase the stress on the system and can result in increases in individual plant failures, particularly in aging plants. During these periods, output in both solar and wind plant is expected to decrease.
- Finally, during these periods, there is increased risk of bushfires that impact system availability.

[16] Figure is from The Australian Climate Change Science Program's report, *Australia's changing climate*, 2016, available at https://www.climatechangeinaustralia.gov.au/media/ccia/2.1.6/cms_page_media/176/AUSTRALIAS_CHANGING_CLIMATE_1.pdf.

All these factors suggest the need for a holistic assessment on how we plan for and operate the system and develop the markets. For example:

- Increased interconnector availability can support the value of resource diversity during most hours of the year.
- Maintaining additional strategic reserves in the system that can be made available during these predictable but rare combinations of circumstances can support system reliability and security.
- Transmission outages arising as a result of bushfires can have a major impact on the resource mix available to affected regions.
- Demand side solutions enhance resilience in the face of major supply disruptions and can reduce the need for major additional investments to cover extreme events.

These factors further illustrate the benefits of planning approaches and markets that value broader resource mix and diversity, better engaging price responsive demand as a viable resource to meet customer demand, and the potential to improve overall energy price outcomes.

# 2. Impact of changes on the operation of the power system

The changes currently being experienced in the power system are impacting system and market operations across the NEM. This has implications for the reliability and security of the power system if not managed in a timely manner, and all directly challenge the way AEMO operates
the system.

Power system security and supply reliability are inextricably linked in power system operations. For example, a major generator or interconnector failure (a reliability issue) may cause frequency to drop, triggering an emergency frequency control scheme (a technical service) which may shed load (but which is not regarded as unserved energy [USE][17]) to rebalance frequency.

AEMO is concerned that if the resources, market, and regulatory designs required for reliable and secure operations continue to be considered separately, the arrangements put in place could result in sub-optimal operating and market outcomes and hence higher costs to consumers.

In the past, power system security has been maintained primarily through investments in generation plant and ancillary equipment, that is:

- The inherent characteristics of conventional generating plant.
- The enforcement of standards on plant seeking to connect to the grid, including obligations to negotiate generator performance standards under the National Electricity Rules (Rules), or meet regional requirements such as the Essential Services Commission of South Australia (ESCOSA) generation license conditions.
- Operating constraints on generators limiting power flows on the grid.
- Supplementary investments by network service providers (NSPs) where planning reviews identify the need.

As the generation mix changes, it is becoming more challenging to maintain the security and reliability of the power grid. AEMO has found it increasingly necessary to both impose constraints on generation and use our directions powers to maintain system security and a reliable operating state.

For example, the high proportion of non-synchronous generation in South Australia means AEMO is often intervening to maintain a balance between synchronous and non-synchronous generation. Using powers of direction to meet the need for a level of conventional plant in these circumstances is necessary but undesirable. It generally leads to higher costs to customers through intervention pricing and the payment of compensation. With time and further devolution of the system in a disorderly way, these inefficiencies will continue to grow.

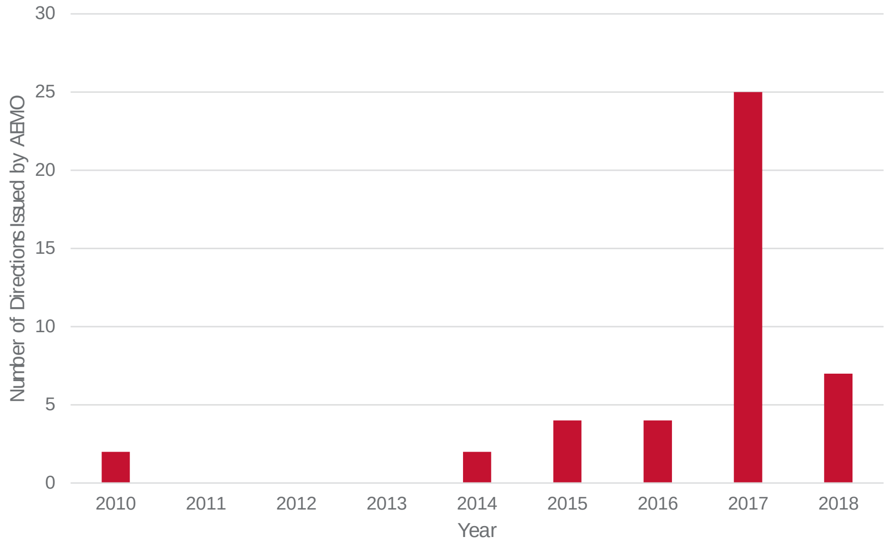
While system strength requirements are currently the most binding, in many cases, if AEMO were not intervening to maintain system strength, other technical requirements such as maintaining minimum

[17] Unserved energy (USE) means energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply), because there is not enough generation capacity, demand side participation, or network capability, to meet demand. The planning reliability standard, as defined in the Rules (clause 3.9.3C), is a maximum expected USE in a region of 0.002% of the total energy demanded in that region for a given financial year. This is discussed further in Appendix A3.

amount of inertia in NEM regions that may be subject to islanding would still require AEMO to intervene via the use of constraints rather than directions.

Figure 23 illustrates the number of directions (mandatory instructions made by AEMO to generators and NSPs for system security purposes) issued in the NEM in recent years.

**Figure 23 Number of AEMO directions in the NEM since 2010**




Note: 2018 is for a partial year, 1 January - 5 February 2018.

The same resources can often supply a number of essential services to support both security and reliability. An efficient approach to market design would seek to co-optimise investment in and deployment of resources to meet these needs.

For example, the frequency control frameworks review is considering how the market attracts, retains, and uses resources to maintain system frequency within standards. Historically, frequency control services have mainly been sourced from conventional generators, and these generators have also supplied the operating reserves required to maintain reliability. In the future, new sources, including battery storage and demand response, will become important suppliers of these services. These new sources will also have important roles in maintaining reliability of supply.

The design of the wholesale energy market needs to drive investment in the right kind of plant capability with the right level of availability at the right times and in the right locations. If the market does not achieve this and efficiently co-optimise operation in real time, both reliability and security are likely to be placed at risk, requiring intervening actions. AEMO recommends that the reviews of power system security and supply reliability should be coordinated to produce a holistic outcome.

In this context, this chapter discusses some of the factors impacting the security and reliability of the power system:

1. The variances in forecasting and the challenges associated with this.
2. The predictability and variability of the resources mix.
3. Market optimisation and efficiency outcomes.

## 2.1 Forecasting

Forecasting is increasingly difficult, due to structural changes in the market on both the supply and the demand side. Traditional forecasting is being challenged, as changes in the nature of demand and character of supply render historical experience less relevant.

AEMO needs to undertake long-term forecasting for planning and shorter-term forecasts for operating purposes. Forecasting expected maximum demand under extreme conditions is particularly important for assessing reliability in both the short and longer terms, but is not the only requirement. AEMO also needs to forecast minimum demands, variable generation output, and net load profiles to secure system operations.

A changing load shape, driven by growth in behind-the-meter resources (including PV, batteries, electric vehicles, and demand side participation) affects both maximum and minimum demand, but also impacts on ramping requirements. This makes understanding of the future daily load profiles increasingly important for understanding risks to system operation.

AEMO recognises the importance of forecasting and is undertaking a number of initiatives to improve the performance of both operational and long-term forecasts. However, given the number of variables involved, attempting to make forecasting more accurate is not the solution by itself. It is critical we recognise that variability is an essential characteristic of the power system and that we need to forecast and manage to the range of possible outcomes.

### 2.1.1 Long-term forecasting

AEMO produces a 10-year electricity forecast for the NEM each year through the *Electricity Statement of Opportunities* (ESOO). AEMO also must publish an annual 20-year *National Transmission Network Development Plan* (NTNDP) and, with that, an NTNDP database, which includes forecasts. Therefore, AEMO has to produce electricity forecasts spanning a 20-year outlook each year. Fortunately, the extension beyond 10 years has little direct impact on reliability, as the NTNDP focuses on improved coordination of transmission, generation, and demand side developments assuming the reliability standard is met.

Forecasting 20 years out adds complexity beyond the transformation of the supply mix and growth in consumer technologies, as it must include climate change and its expected impacts on extreme temperatures. Since the extreme weather review, AEMO has included the impacts of climate change, in particular in relation to the impact of the temperature warming trend on maximum demand. AEMO's 2016 *National Energy Forecasting Report* (NEFR)[18] refined the methodology for 20-year electricity consumption and maximum demand forecasts, and our 2017 *Electricity Forecasting Insights* (EFI)[19] incorporated a heatwave variable for the first time.

The historical record of long-term forecasts by AEMO and other parties indicates the difficulties. AEMO's 2017 *Forecast Accuracy Report*[20] lists a number of initiatives AEMO has taken or planned as we seek to improve those forecasts. Efforts are continuing to improve forecasting to the 10-year horizon and to include scenarios and undertake separate analysis to reflect the range of likely outcomes in decision-making.

### 2.1.2 Short-term forecasting

AEMO also has a program of work to improve short-term forecasting systems, including:

- Developing trials of wind and solar participants submitting their own 5-minute forecasts supported by sophisticated self-forecasting techniques (such as sky-cam, light detection and ranging (LIDAR) technology, and cloud monitoring).
- Obtaining high resolution (1-minute) data from the Bureau of Meteorology and increasing the number of observation sites.
- Using data science and probabilistic forecasting capability to better provide quantitative, dynamic assessment of risk of lack of reserves.

AEMO's program of work for summer 2017-18 has seen a range of improvements implemented and close liaison between AEMO's operations group and forecasters.

[18] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

[19] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights.

[20] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2017/FORECAST-ACCURACY-REPORT-2017---final.pdf.

### 2.1.3 Forecasting supply availability and risk of non-supply

Forecasting system reliability and identifying potential reliability gaps (as reported in the ESOO), used to have two main dimensions of uncertainty:

- Demand (where the maximum demand distribution was approximated by weighting 10% probability of exceedance (POE) and 50% POE outcomes); and
- Credible generator forced outages modelled through stochastic simulations.

The range of variables and scale of forecast risk in both supply and demand has now expanded, with both now being subject to the vagaries of weather.

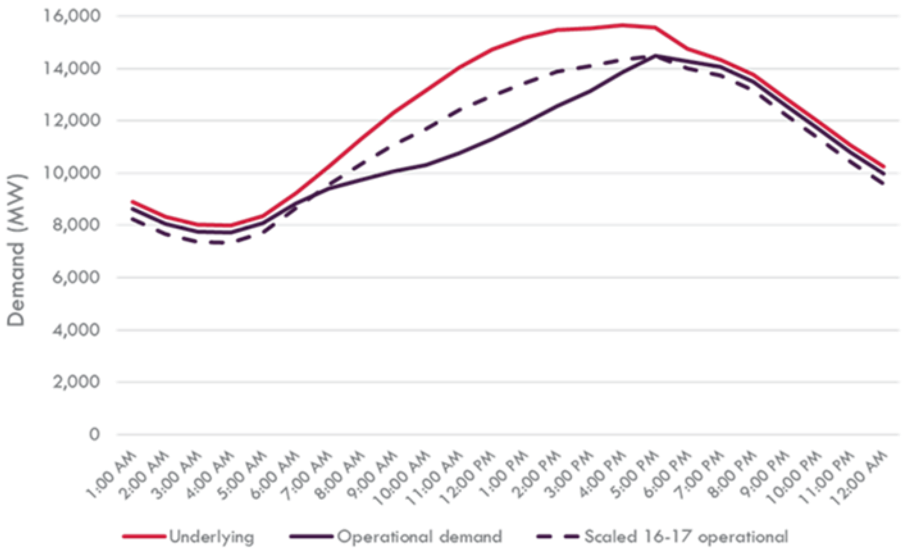
The existing NEM reliability standard, as defined in the Rules, is a planning economic benchmark that requires expected USE to not exceed 0.002% of consumption per region in any financial year. AEMO implements the reliability standard in the 10-year outlook by forecasting the USE expectation under a range of system conditions to try and capture these uncertainties probabilistically.

Risks of non-supply will therefore be higher than this expectation during extreme peak conditions and/or when real-time supply and demand conditions are worse than assumed in the modelling, such as higher generator outages.

AEMO analysis shows it is possible to have sufficient resources to meet the reliability standard while simultaneously showing a high risk of insufficient supply to meet demand under more extreme, but still plausible, future conditions. The changing demand profile is contributing to this growing difference in the expected level of USE and exposure to potential supply shortfalls at times of peak demand[21].

The installation of high levels of embedded solar PV generation across the NEM is leading to a later and shorter peak in the operational demand[22] or net demand on the system. Figure 24 shows this effect.

**Figure 24 Changing load shape is resulting in a shorter and later operational demand peak**




By way of example, USE of 0.002% for New South Wales in 2022 (forecast based on a neutral growth scenario) is the equivalent to 1,280 MWh, or approximately 644,450 households off supply for one hour, or 107,408 households off supply for six hours. A shorter operational peak results in higher MW at risk (though for shorter duration) and increased probability of load shedding within the USE allowed under the reliability standard. This means the outage impact is likely to be more widespread, affecting more households over the most extreme heat period.

The value of customer reliability during a severe and widespread outage is likely to be higher than at other times. Further, increasing extreme temperatures from climate change and urban development means

[21] This analysis is discussed further in Appendix A.3.

[22] For the definition of operational demand AEMO uses, see http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights.

increased health and safety risks from non-supply during these events compared to when the reliability standard was first established.

With more MW at risk for the same level of USE, it is understandable that the USE measure is becoming more sensitive to 10% POE demand conditions, and weather-driven variations in input assumptions more generally. With increasing growth in variable renewable energy resources, both demand and supply are now exposed to the vagaries of weather, such as wind and solar availability, impacting AEMO's ability to meet demand on extreme peak days.

AEMO's reliability simulations show situations with sufficient resources to meet the reliability standard while simultaneously showing the probability of load shedding during high, but still plausible, demand conditions to be an almost certainty. For example, in Sydney, temperatures of 40ºC or more could be the catalyst for extreme
(1-in-10 year) electricity demand, if these temperatures are experienced towards the end of the day when business demand is still relatively high, residential demand is increasing, and rooftop solar generation is declining.

Involuntary load shedding during an event where there is not an obvious cause does not appear to meet community expectations, however increasing supply to meet demand should also not be an opportunity for over-investment and create the potential for increased costs to customers.

In this context, there is an urgent need to consider development of an operational reliability standard so AEMO is equipped with the tools and market frameworks to operate a secure and reliable system at the lowest cost. AEMO proposes considering other reliability metrics together with a USE standard to better reflect an economic target for reliability at the same time as a minimum amount of reliability operationally.

In developing such measures, it is instructive to consider how similar challenges have been approached in other jurisdictions. For planning and decision-making, there are a variety of reliability measures adopted in power systems around the world, summarised in Table 3 below. Examples included have been taken from entities that operate in power systems with high penetration of VRE.

**Table 3 Examples of reliability measures**

| Reliability metric | Description | Example |
|---|---|---|
| Expected unserved energy (USE) | Total expected amount of energy demand not met in a year, weighted by probability of occurrence. Provides information about the severity of events. | In the NEM, this is expressed as a percentage of total consumption. |
| Loss of Load Probability (LOLP) | The probability that on any given day (or hour) the available capacity will be less than the demand.<br>Does not provide any indication of the severity of any loss of load event. | To support operational decision-making, the new medium-term projected assessment of system adequacy (MT PASA) redevelopment will report daily LOLP for the next two years, in addition to the USE metric. |
| Loss of Load Expectation (LOLE) | The number of days (or hours) per year where available capacity is insufficient to meet demand. | ERCOT's reliability standard is one loss of load event every 10 years* (0.1 LOLE). |
| Loss of Load Hours (LOLH) | The number of hours in a year that generation could not meet demand. One LOLE can consist of one or more consecutive loss of load hours. | EirGrid's reliability standard is 8 LOLH per year.<br>National Grid targets <= 3 LOLH per year. |

* ERCOT is moving towards calculating economically optimum and market equilibrium reserve margins in lieu of reserve margins based on 1-in-10-year LOLE which is a physical reliability standard.

We note that there is no one technique that is uniformly applied internationally, although reliability standards expressed as a frequency of interruption are more common than the type of probability standard adopted in the NEM.

As USE incorporates multiple dimensions, including the frequency of load shedding, quantity of load shed, and duration of the load shedding event, it is inherently a more complex measure. Consequently, forecast USE is highly sensitive to small changes to assumptions, particularly those that drive the likelihood and severity of scarcity events. For example, only minor changes to supply and forecast demand for Victoria cause expected USE to drop from 0.0023%[23] to 0.0005%. The input data and modelling uncertainty alone can cause the USE to go from well within the reliability standard to exceeding that standard.

Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE) are less sensitive to small changes in the supply-demand balance when reliability is near the standard, since the severity of the scarcity event is not considered.

### AEMO undertakings

AEMO is therefore reconsidering how we implement the current reliability standard and report operational and economic information to assist planning, to ensure the future risks of non-supply are adequately captured and reported. Such information will be provided in future ESOOs.

AEMO is also engaging with the Bureau of Meteorology, among others, to do more analysis on how best to model the effect of weather and climate change in our demand and supply forecasting. Recent enhancements already being implemented include:

- Tracking, and including the impact of, smaller renewable projects not previously captured in AEMO's survey of generation projects.
- Using multiple weather years to capture variations in contributions of wind and solar generation at times of high demand, and increasing frequency of heatwave events.
- Refining the generation profiles for future committed wind and solar projects to represent the expected generation from a wider range of locations within the NEM (also important for modelling of renewable energy zones for the Integrated System Plan [ISP]).
- Collecting data to allow better modelling of generation and interconnector limits and outage risks during extreme temperature conditions.

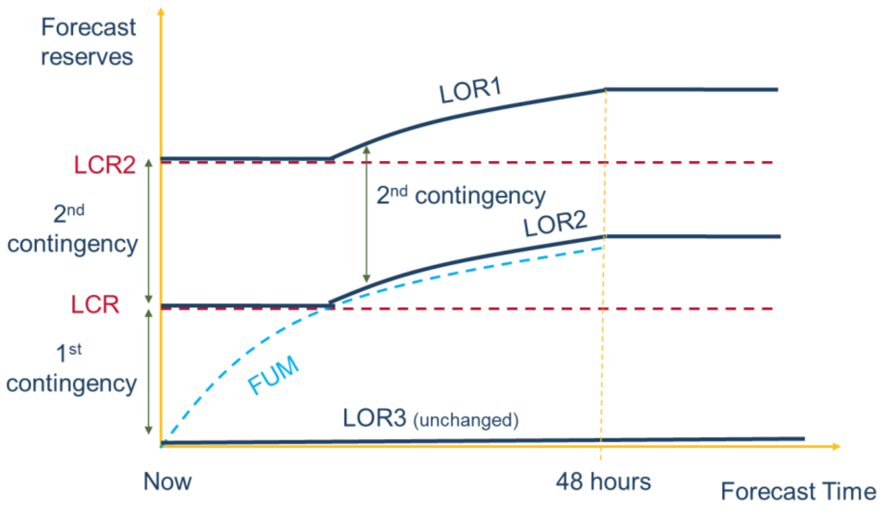
[23] These figures are based on the latest modelling for 2017-18. These results are higher than was forecast in the 2017 ESOO, predominantly due to higher generator forced outage rates seen on the system.

### 2.1.4 Forecasting Uncertainty Measure (FUM)

Recent rule changes have allowed a risk-based approach to forecasting and reserve assessment. The new Forecasting Uncertainty Measure (FUM) expands on historical considerations such as ambient weather and power system conditions to consider the three systems (scheduled generation, semi-scheduled intermittent generation, and operational demand[24]).

As the proportion of variable generation in the NEM rises, the FUM will result in more accurate collation of the reserves needed to manage uncertainty and maintain reliability. Without change in the market design, this is likely to lead to AEMO declaring a LOR more often and intervening in the market more often.

**Figure 25 Application of the Forecast Uncertainty Measure to reserve calculations**




The three forecasting systems mentioned above have been combined with regional temperature and wind speed forecasts to produce a dynamic FUM value for each region for the short-term projected assessment of system adequacy (ST PASA) forecasting horizon. By being able to coordinate all these forecasting assets of the power system, AEMO is in a better position to be able to foresee the range of probable events and inform the market of them[25].

## 2.2 Resource predictability and variability

Increased VRE means the weather itself is a fuel source. This presents challenges for adequate system operation for two reasons:

- The weather is largely stochastic. It can be analysed statistically but cannot be predicted precisely, and, despite best practice, risks cannot be managed through forecasting alone.
- The weather is variable. Regardless of our ability to predict the weather, the market arrangements were not designed for the large shifts in VRE that we are observing.

Forecasting was previously accomplished with higher degrees of certainty, based on historical circumstances, with forecast errors mainly due to major economic changes or weather events. This is no longer true. The combined effect of the shifts toward weather as a fuel source and toward decentralised resources is fundamentally changing the operating dynamics of the power system.

[24] Scheduled generation: Every scheduled generator is required to submit an estimate of available capacity of each scheduled generating unit for every trading interval for the next eight days. This provides AEMO with an estimate of how much generation is available for dispatch and may be updated at any time up to the point of dispatch. Semi- and non-scheduled generation: AEMO continuously updates generation forecasts for every semi-scheduled generating unit and large intermittent non-scheduled generating unit through our AWEFS (wind) and ASEFS (solar) forecasting systems. Operational demand: AEMO continuously updates operational demand forecasts at a regional level.

[25] Further information on the background to the FUM can be found in AEMO's proposal for Rule change at http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions.

As mentioned, AEMO has put in place measures to improve our forecasting, and is working with climate scientists to better understand the risks of climate change on future reliability and power system operation. Beyond current levels of VRE, resource uncertainty and variability will place increasing demands on flexible, dispatchable resources to be online and able to respond at the right times and in the right place.

### 2.2.1 Variability

Variable resources generate as available, leaving the residual to be supplied by conventional resources, such as coal, gas, hydro, and storage. Demand is also becoming more variable, and this variability is expected to grow as embedded generation, storage, and intelligent local response grows. The need for flexible resources then arises from both the variability in the forecast and the rate of change in net demand – or the unpredictability in demand plus the ramping requirement.

In severe cases, the rate of change in demand and variable generation results in a large sustained change in the residual demand, typically occurring from the middle of the day to the evening peak. It is associated with large reductions in wind generation coinciding with a similar reduction in rooftop solar generation over the same period.

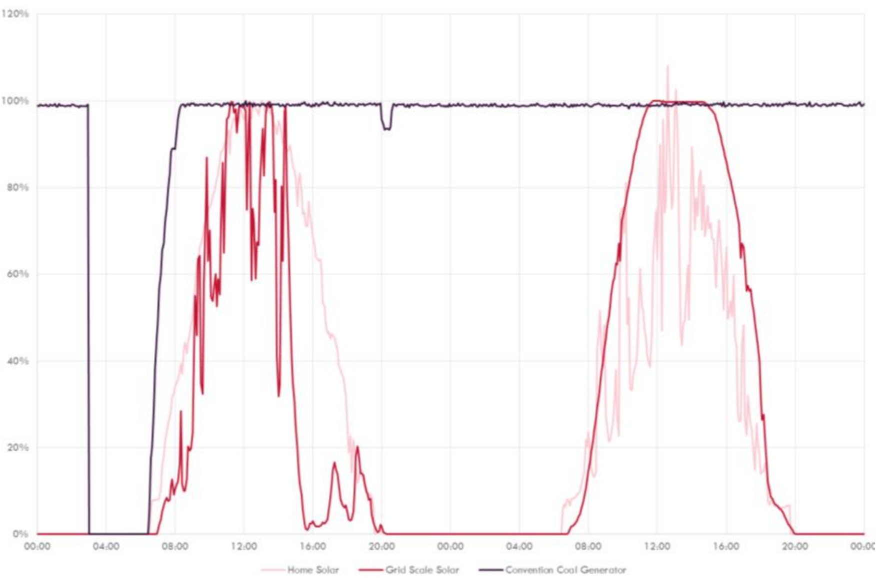
Variability is a result of two issues:

- Residual uncertainty that cannot be addressed by improving forecasting.
- The inherent tendency for the fuel source – the weather – to change forecast or not.

Figure 26 compares residual uncertainty from conventional generation, and grid-scale and home (rooftop) solar generation, on consecutive but different days. Solar uncertainty on a cloudy day in particular creates challenges for the current framework:

- Solar variability results in large swings of power output in real time, creating issues related to frequency and voltage control and network loading. While these are manageable at present because of their size and
  geographic diversity, it is a developing concern which, without necessary market changes, will require more intervention.
- Cloudy days produce less energy than sunny days. The grid-scale plant in Figure 26 produced 60% of the energy on the cloudy day that it produced on the sunny day. The reliability standard is intended to drive investment to deliver the energy, but is inadequate to cover the operational variability.

**Figure 26 Residual uncertainty of conventional and solar generation**




An example of the extent of variability on the power system is illustrated in the case study below.

**Case study 1: Wind ramping, South Australia, Wednesday 29 November 2017**

As Table 4 shows, the forecasts for the peak demand of this day changed six days, three days, and one day prior, then six hours and one hour before the peak. Leading into the peak demand, the semi-scheduled (VRE) generation increased from 162 MW six hours out from the peak to 704 MW (at the peak). This was double the semi-scheduled generation forecast six days ahead, and almost four times higher than forecast six hours ahead.

On this day, LOR was not triggered, although the event highlights the considerable changes in a range of key forecast variables. This sort of variability in a range of circumstances has a significant effect on efficient use of plant and the management of reliable supply.

**Table 4 Supply demand forecast for South Australia for Wednesday 29 November 2017 (case study 1)**

| | PASA run | Demand (MW) | Forecast temp (C) | Generation (MW) | Imports (MW) | Reserves (MW) | VRE (MW) |
|---|---|---|---|---|---|---|---|
| 6 days | 23/11 12:00 | 1,921 | 35 | 2,473 | 817 | 1,368 | 369 |
| 3 days | 26/11 12:00 | 2,112 | 36 | 2,532 | 792 | 1,212 | 421 |
| 1 day | 28/11 12:00 | 2,337 | 37 | 2,355 | 820 | 838 | 190 |
| 6 hrs | 29/11 11:30 | 2,400 | 38 | 2,258 | 743 | 600 | 162 |
| 1 hr | 29/11 16:30 | 2,550 | 39.1 | 2,967 | 486 | 903 | 744 |
| At peak | 29/11 17:30 | 2,399 | 39.1 | 2,889 | 541 | 1,031 | 704 |

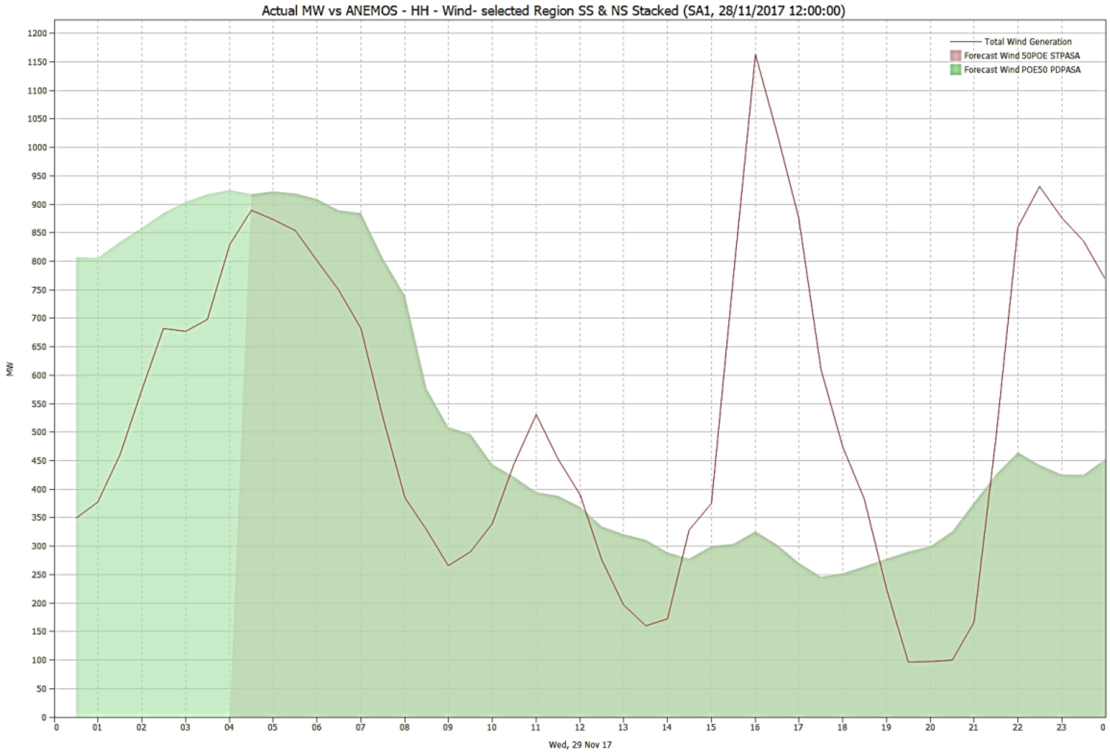
The weather condition and wind forecast (see Figure 27) was:

- A warm air mass forecast to be directed across South Australia and Victoria from Tuesday 28 November 2017 until Thursday 30 November 2017 ahead of a low pressure trough.
- With strong northerly breezes limiting any sea breeze relief, temperatures to peak at 37°C in Melbourne, and 38°C in Adelaide.

On the day (also shown in Figure 27):

- Temperatures reached 35.9°C at Melbourne Airport and 39.1°C at Adelaide (Kent Town).
- Wind was highly variable, associated with a cooling change and hence, change in wind direction and speed across South Australia.
- Wind generation peaked at 1,163 MW at 16:00, before reducing to 96 MW at 19:30 and subsequently ramping back up overnight to around 900 MW.

**Figure 27 Day-ahead forecast compared with actual wind output in South Australia, 29 November 2017 (case study 1)**




AEMO found that:

- Moderate to low wind conditions were forecast in South Australia six days and three days ahead (200 MW to
500 MW across peak demand). Wind forecast variance was considered a key downside risk to supply accuracy.
- A sudden increase in wind generation improved the reserve position. This was not predicted even six hours out.
- The run of warm days across Victoria and South Australia had not been experienced for some time, increasing peak demand forecast uncertainty.
- Reliability risks associated with VRE forecasting uncertainty will be better captured and incorporated into the PASA process through the introduction of the FUM.

The second case study below describes recent ramping events and the actions AEMO needed to take to manage them. Extending these operational experiences to a future with higher shares of VRE and reduced levels of dispatchable generation highlights both:

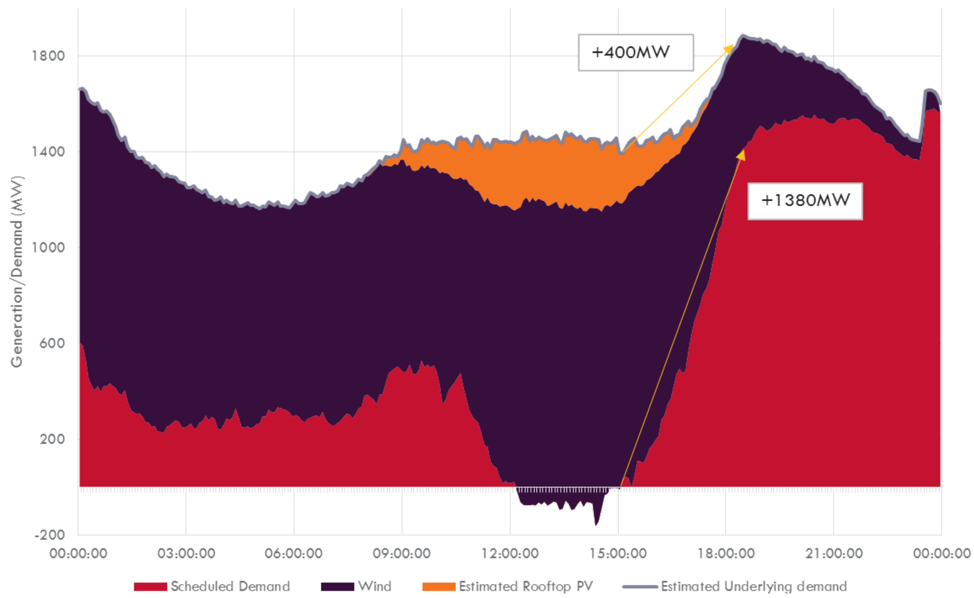
- Why optimised dispatch of a diverse range of "as available" and "on demand" resources will be required.
- Why the current market design, without an explicit value on dispatchability and flexibility, without the ability to optimise across an extended period of time, and without co-optimisation of the diverse resources, will not result in the desired economic outcome.

**Case study 2: Flexible plant ramping, South Australia, Sunday 23 July 2017**

On this day, demand in South Australia was typical for a winter Sunday. High levels of wind and solar in the middle of the day meant that the combined generation from VRE was higher than from scheduled generation.

From around 15:00, wind energy reduced considerably while solar energy reduced as the sun set. This resulted in a 1,400 MW increase in the dispatch of scheduled generation (both in South Australia and over the interconnector with Victoria) over three hours (see Figure 28). In this example, "Scheduled Demand" refers to demand supplied by scheduled generating units.

**Figure 28 Flexible plant ramping, South Australia, Sunday 23 July 2017 (case study 2)**




Variability that causes large sustained changes in residual demand has increased by 70% over the last decade in South Australia, with ramps in excess of 1,000 MW common.

In addition, AEMO has found that for the March 2017 to August 2017 period, maximum ramp rates were 20% to 75% higher than the same period in 2010. As ramp rates get larger, operating strategies would be needed to manage the potential for such events, which include:

- Ensuring interconnectors have sufficient headroom to absorb the ramp, which may require operating at full
  export capacity.
- Ensuring sufficient headroom on flexible dispatchable plant (on either side of the interconnector if relying on imports to pick up part of the ramp). In South Australia, more than half the ramping capability is from three power stations. This may require several units operating out of service prior to the ramp, and then being called into service taking into account required start-up times.
- Managing energy storage systems. While batteries can typically move very quickly, they generally have limited storage and would not be able to sustain full output over the period in question. Pumped hydro, if installed, would likely have a greater energy capacity and could absorb some of the VRE ahead of the drop off, which would help on two accounts:
  - By storing energy to release when VRE output reduces, and
  - By adding demand for other flexible dispatchable generation to be able to operate at minimum load in readiness for the ramp event.

  This type of coordination of multiple resources is likely going to be required in the future.
- Developing more flexibility in the demand. Having the ability to rely on flexible demand resources in the aggregate means the virtual power plant (VPP) aggregator can support and deliver capability to manage weather uncertainty. In this circumstance, AEMO will be able to use both demand and supply to deliver optimal economic and
  reliability outcomes.

## 2.3 Market optimisation

Chapter 1 of this submission presents analysis and evidence of the changing economics of investment in the NEM.

A significant body of work by researchers and stakeholders suggests that a market design based on a single spot price for energy will fail to deliver the range of services necessary to maintain security and reliability. In the long term, this has potential to not deliver these services at all, because plant with zero fuel costs will be marginal and will set the price at zero or negative for an increasing proportion of the time. For example:

- Modelling prepared with the support of the Australian Renewable Energy Agency (ARENA)[26] demonstrated that:
  - High penetration of renewables in a concentrated market increases volatility to a point where it starts denting market efficiency considerably, and
  - Achieving flexibility requires additional investment which can only happen if the market design has targeted instruments to value flexibility.
- Nelson[27] noted that relying on extreme volatility is unacceptable to investors in long-lived infrastructure, while the market price cap would need to increase to $60,000/MWh to 80,000/MWh to deliver reliable outcomes with a high presence of renewables.
- Ernst & Young[28] , in advice to the Reliability Panel, noted that the market price cap is too low to encourage new marginal generation.
- AEMO has determined the value of customer reliability (VCR)[29] to be in the range of $25,000/MWh to $29,000/MWh for residential customers, and up to $47,000/MWh for business customers.

These findings indicate that the market price cap needed in an energy-only market to achieve reliability with high penetration of renewables may be above the value consumers place on reliability. While not all

[26] D. Chattopadhyay and T. Alpcan, *Capacity and Energy-Only Markets under High Renewable Penetration*, June 2017, available at https://arena.gov.au/assets/2017/06/Chattopadhyay-and-Alpcan_3.pdf.

[27] T. Nelson, *Redesigning a 20th century regulatory framework to deliver 21st century energy technology*, available at https://www.gci.uq.edu.au/filething/get/10956/27.%2021st%20century%20regulatory%20system.pdf.

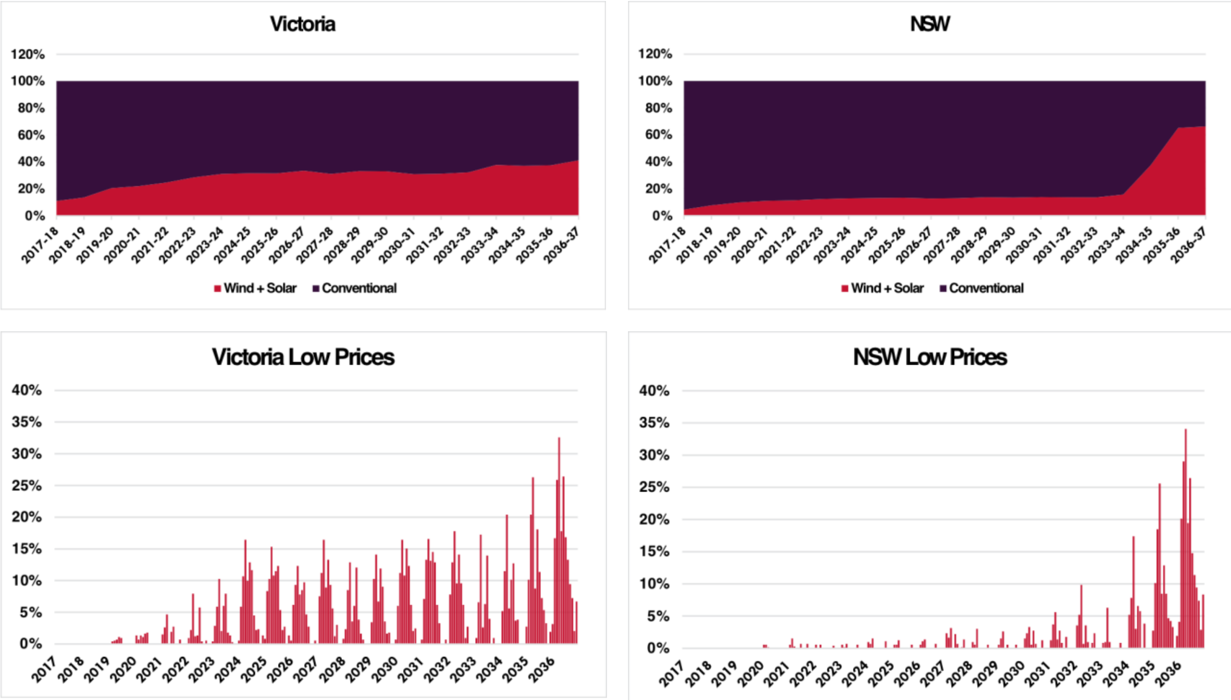
[28] Ernst & Young. *Reliability Standard and Settings Review 2018 – Modelling Report – DRAFT*, November 2017, available at http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018.

[29] AEMO, *VCR Fact Sheet*, November 2016, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

of this is universally supported, it demonstrates the urgent need for more rigorous investigation of the fundamentals of the reliability framework tested against a future with high shares of VRE.

Preliminary AEMO modelling for the ISP shows wind and solar penetration is now near 50% in South Australia, and expected to exceed 30% in Victoria in 2023-24. Figure 29 shows the modelled share of wind and solar in Victoria and New South Wales to 2036-37, and the percentage of time the spot price would be zero or negative in each month of the modelling period. Results for South Australia are generally similar to Victoria, and Queensland and Tasmania are generally similar to New South Wales.

**Figure 29 Integrated System Planning modelling for forecast VRE penetration and prices in Victoria and New South Wales, 2017-18 to 2036-37**




AEMO's modelling results largely confirm the research summarised above, which suggests the incidence of extreme low prices escalates considerably when VRE penetration exceeds about 30%. At this point, AEMO considers that the energy-only market design will fail to attract, retain, and schedule energy resources efficiently.

The assumption underpinning NEM market design is that generators will bid in to avoid contract risk. However, this contract risk only occurs when the generator perceives prices will be higher in the market than its contract price.

In a future with high VRE penetration, energy prices should be expected to be lower on average and even negative. However, such energy prices will need to be accompanied by increasingly high incentives for other grid services, such as flexibility and availability. The real-time spot price does not provide an explicit and transparent value for the flexibility and dispatchability that is required in the system to keep operating reserves.

In many hours of the day, the actual and forecast presence of zero marginal cost resources is keeping the spot price low. Dispatchable generators that have higher short-term marginal costs than the market prices will rationally not bid during these periods, for fear of driving prices even lower.

This is the appropriate price signal with regards to energy, as it indicates that the system does not need more energy but fails to indicate that the system needs flexible, dispatchable resources at those times. It is during these periods that AEMO will rely on these resources to deal with supply variability and uncertainty.

In effect, the single price for energy no longer accurately prices the value of these capabilities, thereby necessitating some level of unbundling and payment for performance to avoid spot price distortion. AEMO's only tool for this now is market intervention, which we are doing increasingly to manage reliability and security risk (see the case study below for an example of a recent intervention). AEMO considers this a sub-optimal result.

The lack of committed new dispatchable generation, poor economic case for investment in dispatchable generation, trends in low reserves, and uncertainty through weather indicate a higher expectation that, if nothing is done to address the investment issue, AEMO must more frequently intervene in the operation of the power system.

Using AEMO's powers of direction to meet the need for a level of conventional plant, while necessary, is undesirable, as illustrated in the following case study. It generally leads to higher costs to customers through intervention pricing and the payment of compensation. It also creates distortion within the market as by definition it leads to directing only utility-scale, synchronous resources available at the time. In the absence of a variety of dispatchable resources that could be assessed to deliver the most cost-effective outcome for consumers, in practice, AEMO's powers of direction are limited to directing thermal generation, except in circumstances where Reliability and Emergency Reserve Trader (RERT) is activated or load shedding is occurring. This is likely to lead to sub-optimal outcomes.

These economic inefficiencies will increase as out-of-market interventions (directions and instructions) become required on a more frequent basis, with Figure 23 illustrating the increasing number of directions issued by AEMO in recent years. AEMO must now order out-of-market unit commitments and re-dispatch as a routine matter in South Australia during certain weather conditions. These interventions lead to pricing inefficiencies, compensation claims, sub-optimal dispatch, and higher costs to customers.

In ESOO[30] publications since 2016, AEMO has consistently signalled the likelihood for USE to exceed the reliability standard in South Australia and Victoria. This persistent forecast of lack of resources casts doubt as to whether the current framework is efficiently incentivising investment in dispatchable resources.

RERT-supported demand response has become the essential tool of last resort AEMO can use to meet the standard. However, our experience in procuring RERT contracts in calendar 2017 has revealed the difficulties in securing dispatchable resources within a 10-week timeframe.

The procurement process for additional demand response under RERT required identification of suitable demand, installation of communications equipment, and completion of negotiations within 10 weeks. However, its design as an emergency measure limits the amount of reserve that can be offered, and comes at a cost of clarity and transparency.

System adequacy concerns, in the absence of market investment, have led to jurisdictions directly investing in dispatchable resources. This should serve as evidence that the current framework is not delivering outcomes that meet the needs of customers and governments, who are demanding a stable and predictable pipeline of resources to replace those that are retiring.

**Case study 3: Directions due to price inadequately valuing services, South Australia, 29 October 2017**

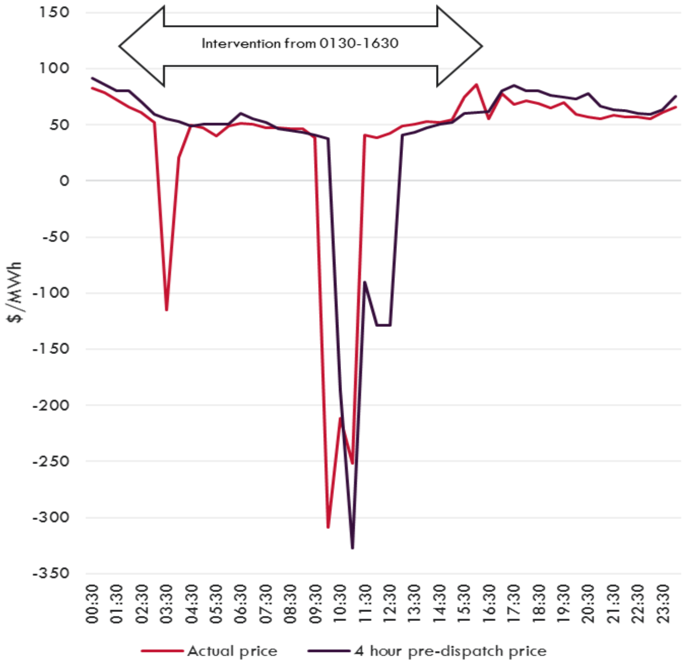
On 29 October 2017, AEMO issued directions in South Australia to ensure system strength would be maintained following a credible loss of generation.

High wind generation (> 1,200 MW) and low South Australian operational demand (< 850 MW) led to forecast negative prices. Consequently, a number of synchronous generators withdrew capacity. AEMO issued directions to keep sufficient synchronous generation online to meet minimum system strength requirements.

During the directions, there were two hours of negative prices (Figure 30). The daily average electricity price on
29 October 2017 was $33.40/MWh, compared to $105.33/MWh for the whole of 2017.

[30] These have been forecast for summer shortfalls under neutral outlook scenarios in the 2016 ESOO (expected for 2017-18) and 2017 *Energy Supply Outlook* (expected for 2017-18 and 2018-19).

**Figure 30 South Australian price outcomes for 29 October 2017 (case study 3)**




The behaviour of the generators was logical in the circumstances. This event, which is typical of a number or intervention events, shows the effect caused by price formation failing to properly value a required system attribute. AEMO has had to frequently direct on generation under similar conditions.

The inter-relationship between security and reliability has been highlighted in recent Australian Energy Market Commission (AEMC) Rule determinations on managing power system fault levels and rate of change of power system frequency. Both these rules establish procedures to obtain the minimum level of service required to maintain the power system in a secure operating state.

The Rules leave open the question whether additional services may be required to avoid congestion or load shedding. Presumably, there would be situations where the service required for system security is less than the service required for system reliability. The gap in service suggests that a classification of security and reliability based on technical aspects of system operation is not clear cut. Again, a holistic view is required with the ability to optimise a diverse range of resources across all requirements.

### 2.3.1 Meeting consumer needs and expectations

Just as the power market cannot be abstracted from the operations of the power system, nor can it be divorced from the needs of consumers. Electricity is, by definition, an essential service and consequently universal access to affordable, reliable, and secure electricity is an underlying element of modern economies. The digitalisation and urbanisation of our society, in Australia and elsewhere, has only increased our reliance.

However, as discussed, at the same time as this reliance has increased, aging infrastructure, combined with weather and climate changes and changes in the nature of the system relied on to supply energy, are challenging both the power system and the markets.

Fortunately, many of the same changes in technology and resources that are creating these challenges for system operations can also become solutions, if approaches to the market and regulatory conventions are re-calibrated to address the changed conditions. In particular, the use of DER coupled with system diversity supported by increased interconnector capability, achieved through appropriate enhancement to the market design and planning process, has the potential of increasing reliability and economic value.

To ensure that the power system remains in a secure operating state, AEMO must always have sufficient resources to respond to potential contingent failures on the system. Standard operating practice throughout the world is for the operator to ensure it always has sufficient reserves available to it to sustain the loss of the single largest resource that could result in system failure. In these circumstances, where the loss of operating reserves on the system would result in catastrophic failure, AEMO historically has had no choice but to rely upon pre-determined involuntary load reductions to keep the system intact during periods where the supply was diminished to a single unit. These are characterised as LOR2 and LOR3 events in the NEM.

Consumers have always reacted negatively to unplanned losses of power. While many consumers appreciate that major storm events are a challenge to the power system, they are understandably less tolerant of power loss caused by simply having inadequate resources on hand to meet periods of high temperature.

Moreover, digitisation of the overall economy has created even greater economic sensitivity to power outages. From a survey of its members after the September 2016 black system in South Australia, Business SA reported median trading and production losses of $3,500 for affected businesses, in an estimated total cost to business of “close to $120,000 per minute”, and called for assurances given business concerns about the cost of future incidents[31]. Involuntary power outages can also cause business consumers to leave the system to achieve higher reliability, which in turn will have negative economic consequences on the overall economy of the system.

In these circumstances, particularly in light of the increase in forecast temperatures for Australia, system adequacy moves well beyond ensuring societal convenience to maintenance of public safety and security.

Historically, the industry’s only path to ensure reliability during peak periods or to address unplanned generation or system outages would be to construct new peaking generation, along with the transmission and distribution necessary to accommodate peak conditions. Due to the relative costs of new versus aging infrastructure, and the fact that, while the system is getting peakier, overall demand is flattening and reducing, all solutions to meet the reliability requirement must be on the table.

With the advent of advanced intelligence in the networks and increased levels of price-responsive demand, the system can achieve higher degrees of reliability using embedded assets on the system. By taking full advantage of the diversity of supply, supported with increases in interconnector capability, DER, controllable flexible loads and storage, a much greater degree of coordination throughout the value chain of the energy system, and a supportive market design, the entire system can be operated to produce a more efficient price outcome and increased reliability and resiliency to weather events.

The net outcome creates a benefit to consumers – a more reliable and secure system at a total lower cost at the meter, and the ability to better use resources that support achievement of environmental objectives.

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[31] See https://business-sa.com/Commercial-Content/Media-Centre/Latest-Media-Releases/September-Blackout-Cost-State-$367-Million.

# 3. The market design should be adapted to meet changing power system dynamics

Electricity markets support both the investment into and operation of resources by individual actors that provide the most economically efficient outcomes for the system and consumers. As the power system has changed and evolved, all over the world market operators and their regulators are adapting the markets to better serve the needs of the changed system. To assure economically efficient, reliable operations of the system, the spot market design must be augmented to support co-optimisation of a highly diverse set of resources to meet reliability and security needs.

Efficient co-optimisation of the full set of resources available to meet these needs is particularly imperative in an environment characterised by high prices, where doing so will support improved overall outcomes for energy customers. This needs to be a driving objective for approaching market design changes in the NEM.

Chapters 1 and 2 outline the key drivers that are underpinning the nature of the changing power system. The analysis demonstrates that, not only do we have current and immediate challenges in the NEM that need to be addressed,
but the underlying drivers are mega trends that will continue to grow in impact on the system and market outcomes
in future.

Specifically, the changing nature of the system is evident through insufficient investment in resources with the flexibility required to meet a changing supply and demand profile and a lack of clear price outcomes to ensure the resources are committed and scheduled.

Australia is not unique. The International Energy Agency (IEA) has published a handbook for policy-makers, which outlines the nature of the changes required to support the transition[32]. While South Australia is demonstrably a world leader in the adoption of variable renewable energy, other regions and the NEM as a whole are moving quickly to levels which the IEA categorises as providing integration challenges. A key finding from this work is the need for increased flexibility to enable the system to manage changing situations and short-term forecasting uncertainty and a necessary focus on system security.

The NEM as a whole already incorporates levels of VRE that exceed those of a number of international markets which have introduced major market changes. The NEM is approaching the level where the IEA states “flexibility becomes a priority”, and the IEA provides information from international markets like California, Texas, and the Mid-West market in the USA that have implemented relevant arrangements to

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[32] IEA, *Getting Wind and Sun into the Grid: A manual for policy makers*, 2017. Available at https://www.iea.org/publications/insights/insightpublications/Getting_Wind_and_Sun.pdf.

assist in addressing that priority. Research by the IEA and the International Renewable Energy Agency (IRENA) is summarised in Appendix A2.

In this chapter, we review how other policy-makers and market operators are adapting to address the changed and changing dynamics of the system. As a general philosophy, AEMO believes that a well-functioning market will supply an optimal result for consumers and through appropriate mechanisms facilitate investment and secure the right levels of reliability.

The characteristics of a well-functioning competitive market are:

- Information transparency and ubiquity – the market requires accurate, reliable, and timely information that is widely available to allow for responses that reflect underlying conditions of supply and demand.
- Ease of entry and exit – new entrants or incumbents do not face costs that others do not have, or have not had,
to incur.
- Level playing field – all competitors, irrespective of their size or financial strength, get equal opportunity to compete. It is not enough if all players play by the same rules. The rules must accommodate the needs of all, whether small or large, so the market is free of impediments to smaller players.
- Predictability – resources are available and provided as expected, the market operator acts consistently and intervenes rarely, and participants have confidence in and sufficient time to respond to signals.

The NEM's flexibility currently lies in the real-time 5-minute market and contract elements. Much of the rest of the world, and the IEA's work, is grounded in spot markets that have strong pre-dispatch commitment arrangements (either daily unit commitments, or capacity mechanisms). Thus, these markets are encouraged to introduce more intra-day trading to allow for greater pay for performance mechanisms. The IEA noted that obligations "to make generation capacity available in the short term to the greatest extent possible" is best practice.

In this chapter we begin our discussion with the need to value flexibility, then look at three areas that we consider will lay the foundations of a well-functioning market and that can begin to capture the value of flexibility:

1. Day-ahead markets.
2. Strategic reserves.
3. Demand response.

In observing the challenges identified in this paper, AEMO is looking forward to working with the Energy Security Board (ESB), the industry, and consumers to fully consider and implement the necessary suite of options to address current challenges and support a competitive transition of the sector that meets consumer requirements – in particular, outcomes that work to reduce the overall retail customer bill while delivering secure and reliable supplies and meeting Australia's carbon reduction commitments.

## 3.1 Valuing flexible performance in the system

In practice, the signals from an energy-only market are complex, and do not always align with system requirements such as operating reserves or ramping.

There are strong financial incentives on generators in the NEM that have entered into financial contracts to be dispatched for the corresponding contracted volumes. This is likely to be reflected in their bids, and hence these generators are more likely to follow schedules set in pre-dispatch. In this sense, a contracted generator is seeking to manage volume risk.

When a generator in the NEM has not entered into financial contracts, they are seeking to manage price risk. For example, an uncontracted gas-fired generator needs to establish whether it will earn sufficient spot revenue after it has incurred start-up, running, and maintenance costs. Managing price risk uncertainty is a challenge, and this is reflected in greater market uncertainty around whether units will be online and spot price outcomes.

The primary incentive for an uncontracted generator to follow pre-dispatch and self-commit is the substantial opportunity cost that the NEM price cap of $14,000/MWh represents.

If pre-dispatch is showing that high prices are likely, then generators will want to be online to capture this. However, without any contractual volume constraints they may aim to optimise revenue based on a price/volume trade off, resulting in variability in unit commitment relative to the pre-dispatch schedule.

Conversely, if pre-dispatch is showing spot prices are likely to be low, generators may rebid volumes into higher price bands or lower their availability. This would be an efficient outcome, as the market is not paying a generator for energy that is not required.

To summarise, and consistent with the directions case study in Chapter 2, incentives around generator commitment decisions in the NEM are influenced by their contracting behaviour and expectations around future spot prices.

A further consideration is that the reliability frameworks need the market to provide the right capabilities at the right time, in the right locations, and of the right size.

As the generation mix changes, the potential of the resources in the portfolio needs to be well understood and valued. Understanding the capability of flexible plant is becoming more challenging today, because:

- The system was not as variable, and dispatchability has historically been a by-product of conventional generation technologies.
- A more diverse range of flexibility needs, which differ substantially across NEM regions, requires a greater understanding of the capabilities needed to operate the power system reliably and securely.
- Demand side resources can be a valuable tool for the market to meet flexibility requirements, but today are largely invisible to and absent from the system.
- There is a strong reliance on market participants to manage the changing system needs through self-commitment and price signals. As the system operator, AEMO recognises that the situational awareness this requires is challenging, given the variable nature of the system and the diversity of the resource mix. This is not surprising, given that the market was designed around the characteristics of traditional dispatchable generation.

The wholesale market is intended to reward dispatchability and durability based on price. While there continues to be value in the spot and contract markets for this capability, AEMO's analysis in Appendix A1 suggests this is diminishing and may no longer be sufficient to drive investment in dispatchable resources, or even to retain existing sources. The chief reason is that these resources are competing with, and being valued in the spot market on the same basis as, non-dispatchable renewable resources which have zero marginal costs and do not offer the same capabilities.

Historically, the level of flexibility to meet rapidly changing system requirements has not been at the level now required. To the extent it existed, flexibility was a by-product of the rather homogenous generation mix (with capability drawn from operational reserves[33] when needed). Thus, it is not surprising that where there are significant levels of variability and reliability risk, at times of either low load or highly uncertain prices, the market is increasingly relying on AEMO to direct on resources as required.

AEMO prefers a design where the reliability requirements are known by market participants in sufficient time to offer in competitive solutions. Intervention to preserve and maintain supply is sub-optimal to the operation of an efficient competitive market, and creates unnecessary operating risks and consumer costs. Cycling of high and low prices resulting from high and low reserves, backed up by last-minute intervention by AEMO, is neither efficient nor transparent, and will reduce consumer and government confidence in the market.

From AEMO's perspective, a preferred outcome will be achieved if the market is adapted to explicitly value requisite capabilities such as operating reserves and flexibility.

This can be achieved through the addition of market-based mechanisms that co-optimise this with the delivery of VRE and other system services, thereby increasing competitive opportunities, which in turn provide consistency between dispatch and pricing of system requirements at any point in time.

## 3.2 Day-ahead markets and operating reserves

The potential benefits of day-ahead markets compared to pre-dispatch needs further consideration and analysis. This analysis needs to be based on current and emerging system dynamics, and to consider the task of optimising a system with much higher VRE and distributed resources.

Our views on short-term forward processes for the NEM are based on:

- A concern that the current 5-minute dispatch and pricing framework may not optimise a more complex set of resources as VRE and behind-the-meter resources dominate.
- The spot price will not be able to form correct signals with high VRE and will not value essential services.

[33] That is, the dispatchable capacity in excess of demand available to AEMO at any given time.

- Plant that provides these essential services is not receiving value for them, and is effectively cross-subsidising
  the market.
- Increased emergency intervention to manage short-term shortages for technical services (such as system strength), reserves, and emerging services such as ramping. Intervention distorts market signals and requires the market operator to make choices that will be sub-optimal.
- Our experience with RERT shows that demand response needs a notice period to bring it to market.
- Fuel coordination also needs notice and price certainty to allow participants to commit to purchase fuel.

AEMO does not agree with the observation in the AEMC's Reliability Frameworks Review Interim Report[34] that day-ahead markets will necessarily require nodal pricing.

Nodal day-ahead markets exist to correspond to nodal real-time markets. The policy objective for the day-ahead market in Texas, for example, was to provide access to the energy market for participants reliant on bilateral markets forward markets[35]. The design decision to implement a nodal day-ahead design was driven by congestion management and a need for consistency with the real-time market design.

The NEM already solves for congestion via the dispatch process in a zonal rather than nodal pricing model. Development of nodal markets should be considered, if necessary, as a future requirement to address high levels of distributed energy scenarios and intra and inter-regional transmission constraints. However, it is not a pre-requisite for the addition of day-ahead unit commitment and markets. Rather, a well-designed day-ahead market can add short-term trading liquidity, value flexibility and demand resources better, and add certainty to the operator of what is available in the real-time dispatch process. This is discussed further below.

Finally, a variety of designs are possible. Designs in the United States provide for combinations of central bidding, bilateral exchanges, coordination of central capacity mechanisms, unit self-commitment, coordination of fuel supplies, and facilitation of central commitment for security and reliability purposes.

In the sections below, AEMO identifies additional features of a day-ahead market design that can be included in the operating spot market to facilitate competition and add consumer value.

### 3.2.1 Adapting the market design to value operating reserves

Supply reliability requires having sufficient operating reserves with the right attributes to be able to meet demand considering what may happen in real time. This includes known variabilities in supply and demand, as well as unexpected events such as the trip of generating units, trip of an interconnector, sudden reduction of wind and solar generation, or higher demand than expected.

As discussed previously, the real-time spot market does not provide a clear, explicit value for the flexibility that is required in the system to keep operating reserves available to meet unpredictable changes in the demand and supply equation and address ramping requirements.

Further, when the spot price is forecast to be low due to high levels of VRE availability, it implicitly suggests that dispatchable flexibility is of little or no value to the system, which, of course, is not the case.

AEMO proposes that exposing the value for reserves and "on demand" energy, and co-optimising this with the delivery of "as available" energy and other system services, would provide a clearer signal for system requirements at all points in time.

Conventional generators, battery storage, and demand side response generally need to be scheduled (or committed) some time in advance to be available to be dispatched when needed in real time or to be available as operating reserves. It is therefore necessary to efficiently coordinate the commitment of resources ahead of real time to deliver an overall optimal dispatch.

The current arrangements expect the coordination of resource commitment to happen by each participant managing the commitment of their resources to manage their individual trading risks and opportunities. This does not, however, equate to system-wide optimal resource commitment. Even with more information concerning the requirement needs of the system, generators and retailers will not take action if they perceive it is contrary to their economic interests. System requirements then go unmet, compelling AEMO to intervene (consistent with our experience, discussed in Chapter 2).

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[34] AEMC. Reliability Frameworks Review *Interim Report*, available at https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review.

[35] Public Utility Commission of Texas. *A Primer on Wholesale Market Design*. Market Oversight Division White Paper, November 2002, available at https://sites.hks.harvard.edu/hepg/Papers/TXPUC_wholesale.market.primer_11-1-02.pdf.

Day-ahead markets are used internationally for exactly this purpose – to optimise the commitment of resources ahead of real time to ensure the resources required to meet demand and provide adequate operating reserves of the right capability will be available to the system when needed. The day-ahead market is needed to schedule resources throughout the day, to allow participants to adjust positions and improve incentives in real time, and to let participants manage risk, especially real-time price risk.

In the NEM, it could work in this way:

- All market participants, including generators, demand side aggregators, and storage providers, know and have an opportunity to bid to meet identified system requirements.
- AEMO is able to co-optimise the full portfolio of resources available to meet all the security and reliability needs of the system. Co-optimisation ideally is done both day-ahead and then throughout the day (real-time) to achieve maximum efficiency.

Explicitly separating out the needs for maintaining an operating reserve from energy puts a clear value on flexibility. Co-optimising the resources that provide energy with those providing operating reserves and other system services recognises that all of these have to be met, and it meets them at lowest possible cost to consumers.

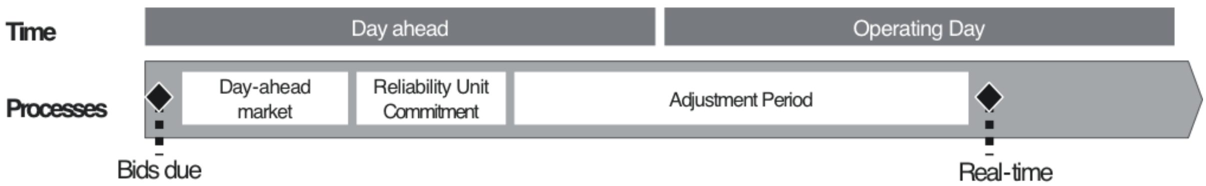
Such a design will build a market structure that would replace the current AEMO intervention process if pre-dispatch does not meet reliability or security requirements. Building market structures provides greater transparency on the costs of residual changes to unit commitment through submitted market offers, and has a more efficient payment mechanism than intervention. Our discussion in Section 3.1 is a simplified example, and Section 2.3 has a case study of an AEMO direction to maintain supplies during a low price period.

### 3.2.2 Operation reserve market designs

Short-term market designs vary widely across international jurisdictions. Appendix A2 provides a summary of the short-term market arrangements in a number of jurisdictions, illustrating that there are range of design options to meet the objectives of giving market participants a short-term trading facility and giving the system operator the ability to ensure scheduled resources will meet security and reliability needs. Some of the design choices are linked to other market structures (for example, whether they have capacity markets). Some require mandatory participation by some resources, while others are voluntary.

While there are options in the design of the market elements, short-term market arrangements generally comprise the elements shown in Figure 31.

**Figure 31 Key elements of short-term reserve markets**




A **day-ahead market** provides a short-term trading platform for submitting bids and offers to buy and sell energy, reserves, and other services. These form financially binding trades and help market participants adjust their longer-term positions and plan for the following day having locked in a price.

A centralised unit commitment process also provides generators with additional ways to manage their risk through choosing to either self-commit or submit multi-part bids that include start-up costs, minimum generation costs, and an energy offer curve. Under a multi-part offer structure, the day-ahead market is able to take into account the entirety of the cost structure of a resource with significant start costs. By doing so, it allows the optimisation to effectively price in this cost. In the context of increasing periods of very low or negative spot prices, this can help the generator ensure the costs are covered, and will lead to marginal cost bidding, rather than bidding at floor price (-$1,000/MWh) to be dispatched, which further distorts the spot price away from true system costs.

**Residual unit commitment** allows the system operator to commit additional resources where needed, based on the multi-part offer. This is likely to be a more efficient approach than the last-minute intervention which is an increasing feature of the NEM. Last-minute interventions are inefficient, often arbitrary, nontransparent, and anti-market. While last-minute operator intervention is a necessary backstop, frequent use indicates a market failure.

The **adjustment processes** allow for changing conditions that occur between the day-ahead assessment and real time. There are different approaches to this. California, for example, implements a sequential approach to short-term markets with three stages:

1. A day-ahead market that optimises unit commitment and co-optimises energy and ancillary services on an
   hourly basis.
2. A real-time market that re-optimises energy and ancillary services on a 15-minute basis.
3. A real-time market that clears energy and flexible ramping products on a 5-minute basis.

Cramton[36] presents a good analysis of the basic features of electricity markets and examines their suitability to handle the large changes that will take place over the next decades. The paper includes a description of the key elements of market design that can be considered.

### 3.2.3 Benefits of day-ahead arrangements

**Short-term trading benefits**

There are currently no exchange-based short-term trading products for the NEM. Introducing such a facility could have a range of benefits.

As shown in Section A1.3 of Appendix A1, the supply of traditional, longer-dated hedge products is decreasing. Shorter-term contracts increase in value with higher shares of VRE with greater reliance of gas as a generation fuel; to assist with firming renewables and to open up the wholesale market to demand side participation. A day-ahead market can provide a more robust platform for short-term trading that would also increase liquidity in longer-dated products, as the position can be adjusted close to delivery.

The flexibility offered by a day-ahead market will be attractive to a number of technology types, including:

- **Renewables**, such as wind and solar, which are better able to manage risk in the short term because accuracy of their forecast generation increases closer to dispatch. The mean error for wind forecasts against actual outcomes is typically below 5% for a 24-hour ahead forecast, relative to a 10-15% mean error for a 6-day ahead forecast. The ability to lock in revenue certainty via short-term contracts ahead of the real-time market would provide short-term liquidity to the market and potentially provide further incentive for investment in firming capability.
- **Pumped storage and batteries**, as they can use the market to lock in the price differential and revenue certainty between low day-ahead contract prices and high day-ahead contract prices. In this way they can assist to support the forward management of variable renewable energy in the NEM.
- **Gas-fired generators** without long-term contracts or shaped contracts, which can utilise the day-ahead market as a way of locking in revenue certainty in the NEM from gas purchased on a short-term basis. This would assist in resolving the uncertainty of price outcome in the real-time market, and facilitate greater levels of contracting and reliability ahead of real-time dispatch.
- **Demand side** participants, as the day-ahead market could facilitate demand response through over-the-counter (OTC) contracted large users selling contracts at times of high forward prices and curtailing their load. They would then earn or pay the price differential between their OTC contracted price and the day-ahead price for the curtailed/sold volume. Equally, users can make use of the timing provided ahead of the real-time market to position production facilities for load reduction and be rewarded at market prices.

One objective of a day-ahead market is to reduce risk for variable generation, battery storage, and uncontracted gas-fired generators participating in the contract market. In the current market construct, if a day-ahead market results in a net increase in contracting, then it would also enhance dispatch certainty, because contracted generators have a strong incentive to be online to manage their contract risk, or to buy contracts back, which would likely result in other generators being online.

[36] Peter Cramton. *Electricity Market Design*, Oxford Review of Economic Policy, Volume 33, Number 4, November 2017, available at http://www.cramton.umd.edu/papers2015-2019/cramton-electricity-market-design.pdf.

**Other benefits of day-ahead markets**

The specific design of day-ahead market arrangements varies widely across jurisdictions, and the options to be investigated should be kept open to capture the benefits.

These benefits could include:

- Improving the ability to meet system needs on a forward basis, to help AEMO ensure that sufficient resources and system security services will be available.
- Improving short-term liquidity and risk management capability for a number of variable and demand side resources.
- Reducing the need for out-of-market interventions for maintaining system security, while reducing associated uplift payments, dispatch inefficiencies, and pricing distortions.
- Co-optimising energy and other system services as separate products across the forward timeframes, thus providing sellers a strong indication of which resources will be needed during future real-time operating periods, informing unit commitment and other business decisions. The financially binding nature of day-ahead markets puts participants in a position to take efficient actions in real time. Without a day-ahead market, real-time market manipulation is much more of a problem, because parties enter the real-time market in less balanced positions.
- Enabling participant bidding and then centrally-coordinated efficient commitment and dispatch of generation and demand response resources with start times longer than a few hours.
- Pre-positioning the system to deal with expected system conditions and potential deviations to help improve system efficiency and reliability.
- Creating incentives for generators and customers to improve their day-ahead forecasting of variable generation and consumption needs, and to manage the associated uncertainties in ways that reduce the total system costs.
- Enabling greater demand side participation for consumers that have flexibility in their consumption as long as it is planned in advance (apt to be especially important for industrial demand response).
- Better aligning the timing of fuel procurement decisions with electricity market dispatch commitments (especially for GPG).
- Providing an additional opportunity for market participants to hedge market risks through less volatile prices, which can be especially valuable to smaller and non-vertically integrated market participants.

## 3.3 Strategic reserves (enhanced RERT)

A safety net is essential to manage the increased uncertainty and risks of USE being observed in the NEM. While AEMO strongly supports preserving the market signals that drive investment, including both high spot prices and a well-functioning contract market, consumers shouldn't be subjected to load shedding to provide these signals. As noted earlier, load shedding is undesirable at all times, however it is particularly acute during high temperature periods where public safety and health is at risk.

Out-of-market reserves act as an alternative to involuntary load shedding, while having no or minimal impact on wholesale market prices and therefore market investment signals. They may also allow for more targeted and efficient improvements to reliability, compared to the relatively blunt tool of adjusting the market price cap.

For example, as AEMO has to respond to significant and prolonged weather events (discussed in Section 1.3), we are also experiencing increased and longer unplanned unit outages due to the aging nature of our infrastructure. Strategic reserves where participants are limited to responding to these times of system duress are particularly well suited to this scenario. Reserves also reduce the need for interventions, and can allow economically efficient resources to provide responses.

Internationally, many jurisdictions procure strategic reserves (see Appendix A2) either as a separate product or as part of a capacity procurement mechanism. In the NEM, we have the RERT framework. This summer, AEMO activated it twice, with a total of 141 MW delivered in Victoria and South Australia, with the potential for RERT contract requirements in other regions in future.

AEMO, with the benefit of industry input, has developed a proposal that calls for enhancements to the current RERT framework to support system reliability in the 2018-19 summer period. AEMO intends to lodge a rule change proposal with the AEMC, seeking changes to the RERT framework to align with a strategic reserve product structure and simultaneously seeking that, at a minimum, the Long Notice RERT framework be reinstated by June 2018 so reserves can be procured ahead of the summer.

### 3.3.1 Procurement horizon

AEMO can only procure RERT services for projected shortfalls that are up to 10 weeks into the future. However,
with the implementation of the Guarantee and Rules concerning generator retirement notice requirements, we
should be made aware of fossil plant shutdowns more than three years ahead of the event (as recommended by
the Finkel Review).

While it is important to allow the market to respond with minimal distortion, it is also important to have time to put any necessary fallback positions in place, and to make stakeholders comfortable that is well under measured control. Allowing AEMO to supplement resources that are developed under the Guarantee to address risk of system failure, particularly during peak periods, will be a cost-efficient and necessary mechanism to ensure the system can meet consumers' reasonable reliability expectations in all periods.

AEMO does not believe that allowing reserves to be procured with a longer lead time is likely to lead to market distortions. Given that the reserves are out-of-market and only activated as a last resort to load shedding, the price signals for market investment (whether as merchant generation or through signing new contracts) would still exist. Reserves would typically only be dispatched during periods of very tight supply-demand, with correspondingly high prices. Firm project announcements would be also considered when determining any reserve requirements or shortfalls.

AEMO also does not accept that that procuring reserves further in advance would necessarily lead to higher costs. Longer-term contracts could potentially reduce the cost of procurement by creating greater certainty for potential resources, therefore driving down the cost of procuring reserves. For example, AEMO's experience with procuring RERT for summer 2017-18 has revealed that there are resources available to the market which require very low (or no) availability payments, but have usage costs above the market price cap. These reserves were not contracted in the market, were unlikely to respond to wholesale market price signals, and have not distorted the market.

AEMO notes it would be important, however, to restrict resources from moving back and forwards between reserves and the energy market. Any scheme should be designed to ensure all resources capable (both technically and economically) of operating in the energy market should do so preferentially.

In summary, AEMO believes strategic reserves would be likely to address the following concerns:

- To act as a last alternative to load shedding and be used during periods of scarcity to avoid load shedding or ensure system security.
- To procure resources that would not or could not otherwise operate in the energy market.

Moreover, when designed appropriately, a reserve market should have the following expectations:

- Preference for resources to participate in the energy market rather than in strategic reserves if possible, so they can be used to deliver economic benefits as well as reliability. There should be limitations on the ability of reserve providers to switch between the energy market and strategic reserves – for example, they would not be permitted to switch on a daily basis.
- Maintain the expectation of being rarely activated, with products not necessarily used in every year.
- Favour resources which have low availability costs but comparatively high usage costs.
- Remain technology neutral.

## 3.4 Price-responsive demand

### 3.4.1 Interactions between wholesale and emergency demand response

The RERT has shown that price-responsive demand is a reasonably low-cost way of delivering reserves to the system, providing there is sufficient notice and price certainty for the service.

As AEMO conceives it, price-responsive demand refers to the ability of individual and aggregate customers to shift their consumption, in response to a price signal, in a manner that is predictable and not intrusive to the use of power.

In a market with increasing levels of variable and non-dispatchable generation, demand-based resource flexibility is an important tool that can be used to increase reliability and efficiency of the system, through the ability of load to:

- Match variable generation output.
- Improve the response to scarcity price signals.
- Supply local system security benefits.
- Increase the value to consumers and investors of existing resource investments, both at the supply and demand side.

Price-responsive demand management takes advantage of the ability to harness embedded intelligence and flexibility in load-based resources, including supply resources, to increase the resiliency, efficiency, and reliability of the whole of system. Distribution utilities are increasing their capabilities to enable this capability to meet local reliability requirements. With a well-coordinated and highly integrated retail and wholesale market, the NEM can increase competition as well as help manage the system in a way that is more efficient and secure, and thereby provides economic and reliability benefits throughout the networks.

Price-responsive load exists in the system today and is growing through the proliferation of DER and advances in control technologies, but is underused. AEMO observes there may be two primary reasons for this:

- First, as a whole, there is significant confusion over the difference between efficient and non-intrusive price responsive demand management and involuntary load shedding.
- Second, demand-based resources can benefit from a market design that supports earlier commitment in advance to price signals and system reserve requirements. Customers and aggregators with this notice have improved opportunities to charge batteries, pre-cool buildings, and optimise their planned use of the resources. In addition, there can be better coordination between AEMO and distribution utilities to ensure that local and grid-based reliability and security needs are harmonised and coordinated.

Demand flexibility and response can either be in-market or out-of-market:

- In-market price-responsive demand would participate actively in the wholesale market, responding to prices and being part of price formation. This means these resources would form part of the overall system optimisation. To maintain supply reliability at an efficient price, demand flexibility can be used both to reduce the very high peaks and to fill in the low load periods during high solar output following the ramp as solar output drops off in the afternoon. The current market design does not support paying for this, and no single participant has the situational awareness that a well-designed market could support to value this capability.
- Out-of-market demand response includes emergency demand response through the RERT, for example, which potentially has a revealed cost of activation higher than the market price cap but below the value of customer reliability of other customers.

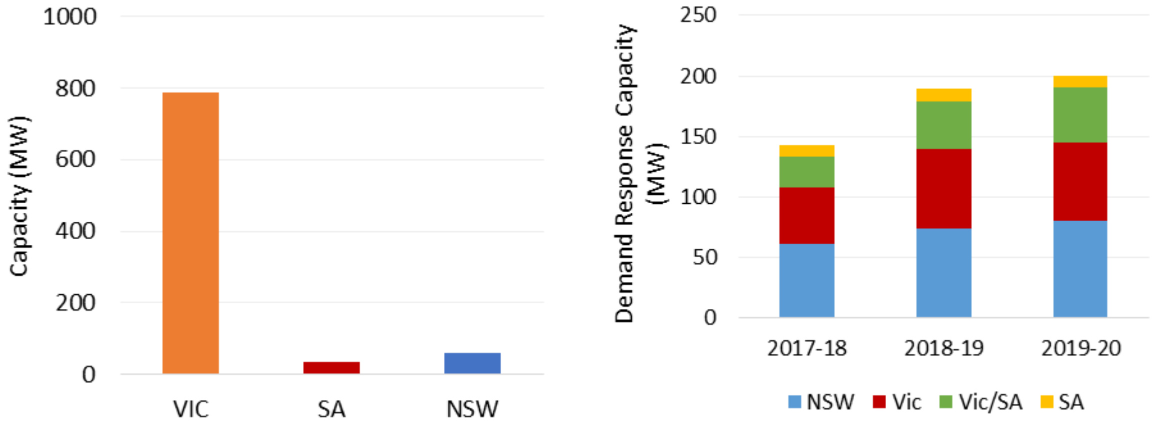
### 3.4.2 Price-responsive demand observed to date

AEMO procured, through the RERT mechanism, a total 884 MW of emergency demand response for summer 2017-18 (summarised in Figure 32 below) across Victoria, New South Wales, and South Australia. This total includes 143 MW delivered through the joint AEMO/ARENA demand response trial.

The AEMO/ARENA demand response trial is a three-year initiative, beginning in summer 2017-18, to pilot demand response projects and encourage other market responses to provide emergency level response when the market response is insufficient. Capacity procured through this trial is also shown in Figure 32 below.

Price-responsive demand is typically broken down by the service it is intended to provide, into ancillary services, network, wholesale, and emergency. To ensure appropriate price formation, regulators and market operators are increasingly revising regulatory and market constructs to ensure accurate and full value is paid for these resources to help support optimal market outcomes.

**Figure 32 Emergency demand response procured for summer 2017-18 and through ARENA/AEMO demand response trial**




## 3.5 Integrated system planning

Key considerations to improving the flexibility of a market include its size and access to resources. For example, New South Wales is more flexible than South Australia, because it is bigger in terms of power (MW) and energy (MWh), and through its access to neighbouring regions. It is logical then that the role of transmission in providing reliability needs to be considered. Stronger connections between the regions will increase the reliability of all regions.

Integrated system plans and approaches to secure necessary infrastructure investments, outlined in the Finkel Review, need to occur for the NEM to be successful. This includes consideration of renewable energy zones, evaluation and approval of increased interconnector capability to improve efficiency and reliability of the markets, and revised regulatory approaches to ensure that necessary infrastructure improvements can be made in a cost-effective manner. Implementing these plans will require a revised planning approval process that is efficient and can take an inter-regional whole-of-system perspective, rather than the current regional focus.

AEMO will be addressing these issues in our first ISP, to be published in June 2018. As part of this planning process, AEMO is also reviewing best practices which will support the ability of the process to identify investment in transmission system resources that improve the overall economics, reliability needs, and/or public policy objectives of the system (such as the creation of renewable zones that, in combination, result in consumer benefit or no or least regrets). Once these investments are identified, we can then apply regulatory processes to ensure that they are constructed in a timely fashion and at reasonable expense.

All vertically integrated utilities, public and private, need to plan to provide the basis for their investment and operating decision-making. With disaggregation of the electricity supply chain into generation, retail, transmission, and distribution, provision of information to all parties through some kind of centralised approach is necessary to ensure the efficient coordination of investment across the industry sectors.

In Europe and the United States, where competitive markets have existed for the last two decades, coordinated planning with a single entity supplying independent advice is the norm. For example, just this month the European Network of Transmission System Operators for Electricity (ENSTO-E) released the first edition of the Bidding Zone Review for consultation[37]. In the US markets, particularly the Midwest-ISO, the PJM-RTO, the New England ISO, and the Southwest Power Pool, there are examples where, despite the presence of competitive markets, a single independent entity develops and coordinates plans to achieve the best outcome for consumers.

In Australia, there has been an increase in State/Commonwealth government direct investment in generation and dispatchable resources. Proposals for direct investment in dispatchable resources by various levels of government have increased to unprecedented levels since inception of the NEM, in all eastern mainland states.

[37] ENSTO-E. *First Edition Bidding Zone Review*. February 2018, available at https://consultations.entsoe.eu/markets/first-edition-bidding-zone-review/.

The reasons for this increased interest in dispatchable resource investment by governments need to be assessed in the context of changes to the market and regulatory framework. To be robust, a framework to support ongoing investment in the NEM must give regard to all expenditure required to maintain a reliable electricity supply, whether or not the expenditure is made by market participants.

The proposed National Energy Guarantee will support new market based investment in needed supply. However, a well-coordinated plan – which also identifies where and how new electric and gas infrastructure can be used to increase competitive alternatives, better integrate renewables, increase the flexibility and resiliency of the overall system, and help reduce the risk of and hence cost of new investments – will support the transition as older units retire and improve value to consumers.

AEMO's experience with the first ISP shows that the planning exercise is helping identify a more optimal combination of investments that meet both individual state and regional needs. The identification of renewable energy zones in combination with increased interconnection capability will be an important feature of the NEM to add flexibility and take advantage of resource diversity.

# A1. Analysis of the investment environment for new dispatchable generation

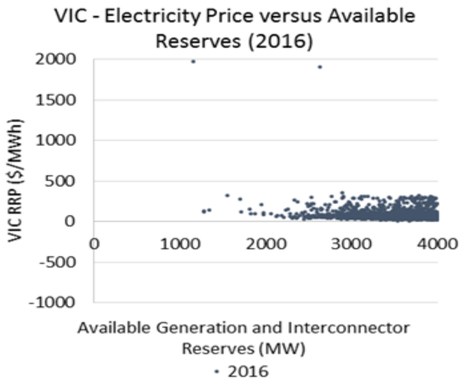
## A1.1 Disconnect between reserves and wholesale prices

There is evidence from the last few years that the theoretical connection between reducing reserves, increasing spot prices, and additional supply is not being borne out in the NEM.

Figures 33 and 34 show that, despite all-time high average spot prices and all-time low reserves:

- The reduction in available generation reserves in Victoria in 2017 did not appear to give rise to increases in volatility.
- Many price spikes in South Australia occur during non-scarce conditions, while price spikes in Victoria have been more in line with scarce conditions – at least this summer – although there were no price spikes at that level in Victoria in 2017.

**Figure 33 Disconnect between reserves and prices – Victoria 2016 and 2017**



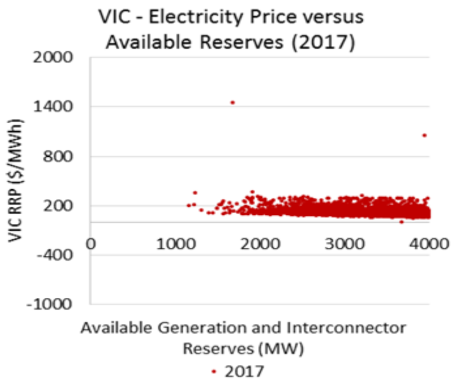
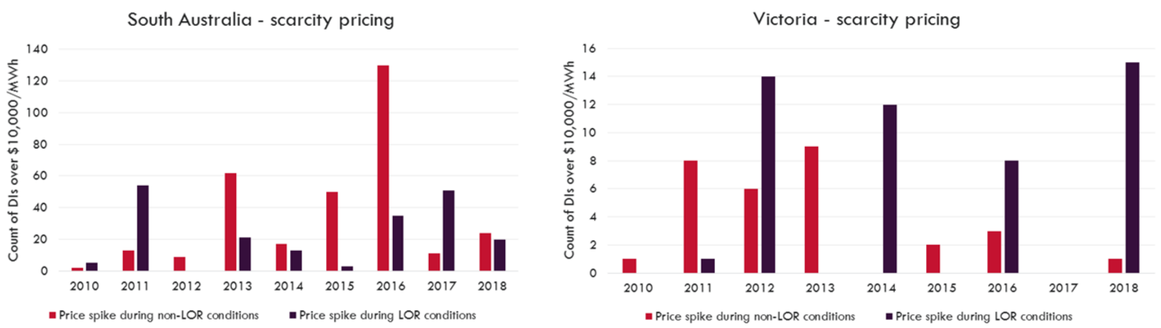



**Figure 34 Incidence of price spikes during LOR and non-LOR conditions, South Australia and Victoria, 2010-18**




# A1.2 Wholesale prices do not support new flexible and dispatchable gas plant

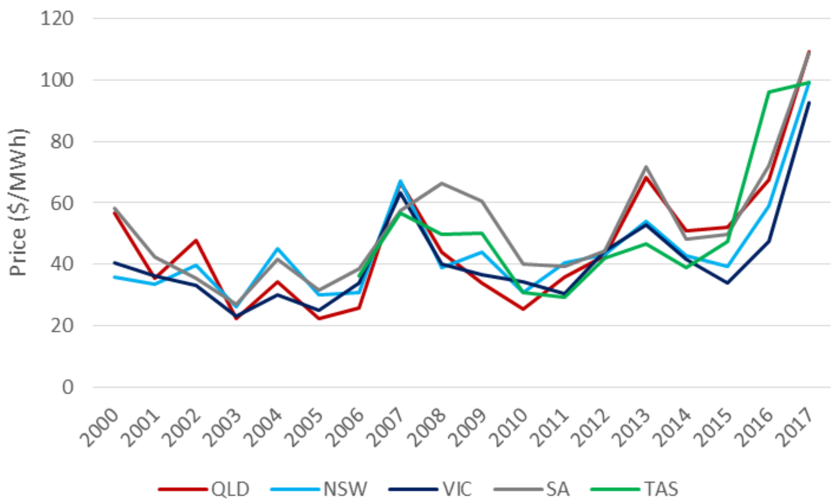
## A1.2.1 Wholesale prices are at a record high

All NEM regions have seen record annual average wholesale prices in 2017, with multiple regions setting record highs. The annual price to date is $101/MWh, 130% higher than the long-term average price.

The current NEM-wide price increase is attributed to higher prices in the majority of periods, indicative of a structural re-basing of prices at a higher level in the short to medium term. Black coal generation dynamics have a significant influence on average prices: the current wholesale price increase across all NEM regions is comparable to the price rise observed in 2007-08, which occurred during a drought which reduced black coal generation.

Figure 35 illustrates the NEM-wide wholesale price increases observed between 2007-08 and 2017.

**Figure 35 Annual NEM wholesale prices, 2000 to 2017**




Increasing wholesale prices have resulted in rising electricity prices for businesses and consumers:

- Large businesses are most exposed to wholesale prices and have received the largest price increases with some reporting doubling or tripling of their bill[38].

[38] Australian Competition and Consumer Commission (ACCC), Retail Electricity Price Inquiry – Preliminary Report, September 17, available at https://www.accc.gov.au/publications/accc-retail-electricity-pricing-inquiry-preliminary-report.

- Wholesale prices make up a smaller proportion of the bill for residential and small business customers, but they have also faced rising prices with increases of up to 20% in the last financial year[39].

## A1.3 The recent business case for gas plant

AEMO's analysis indicates that current and future projected wholesale market prices do not provide sufficient financial incentive for new dispatchable gas plant. This analysis is based on GPG as a likely candidate for new dispatchable capacity that can operate reasonably flexibly and for extended periods. Other technologies, such as reciprocating engines, are also being considered by participants because of attractive properties like their fast start and ramping capabilities.

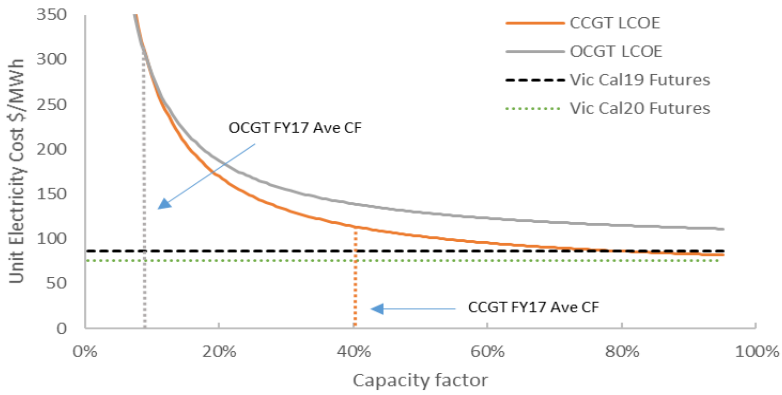
Based on the conservative assumption of $7.50/gigajoule (GJ) fuel input cost:

- New build open cycle gas turbines (OCGTs) do not break even over the asset lifetime.
- New build closed cycle gas turbines (CCGTs) only break even if they have an 80% capacity factor. This is a very high utilisation rate, twice the capacity factor of a typical CCGT in 2016-17.

Market price is forecast by most market analysts to continue decreasing in the medium term, further eroding incentives for new build dispatchable plant. Increases in demand side participation would provide a welcome increase in dispatchable resources through demand response programs, and are also likely to put further downward pressure on future prices. From 2020, futures prices and AEMO's own projected energy prices are considerably lower than the levelised cost of electricity (LCOE)[40] of a CCGT and OCGT at all capacity factors.

Figure 36 illustrates the continued reduction in the business case for new build dispatchable gas plant. As wholesale market price projections are critical for asset valuations, prospective builders are unlikely to build new dispatchable plant under current and forecast market conditions.

**Figure 36 Comparison between the LCOE of new build OCGT and CCGT and forward price curves**




### A1.3.1 Reduced wholesale market volatility

The business case for peaking plant has also been eroded by reduced market volatility. Peaking generation captures value from high-priced periods, yet high-priced periods (trading intervals where the price of energy is above $300/MWh) now occur less frequently. Market volatility across all NEM states has been decreasing since 2009 due to factors such as decreased demand and increases in vertical integration and hydro generation.

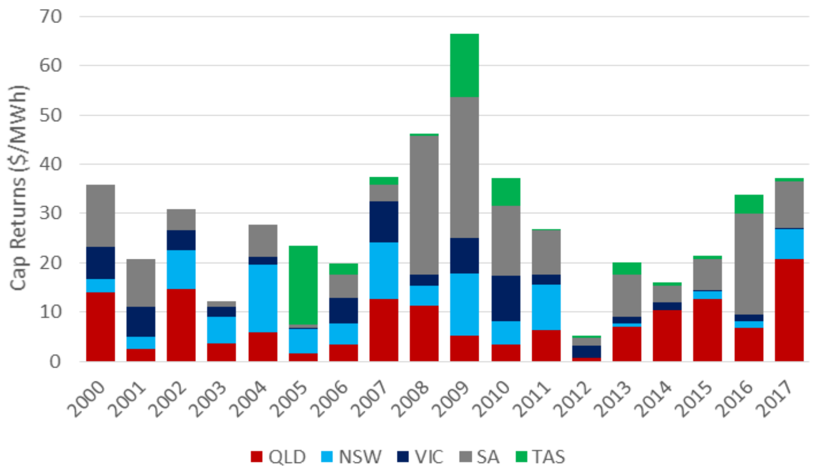
While price volatility in New South Wales and Victoria has been relatively infrequent since 2011, volatility has been observed in Queensland and South Australia due to market power effects. In South Australia, tight supply-demand conditions (exacerbated by the temporary mothballing of half of Pelican Point Power Station's capacity from winter 2016 to July 2017) also contributed to market volatility.

[39] AEMC, 2017 Residential Electricity Price Trends, available at https://www.aemc.gov.au/markets-reviews-advice/2017-residential-electricity-price-trends.

[40] The LCOE is a proxy for the average price (per MWh) that a generator must receive in a market to break even over the asset lifetime.

As dispatchable capacity in the NEM continues to decrease, its effect on market volatility is yet to be determined. While Hazelwood's retirement was followed by record high average prices in Q2 and Q3 2017, the number of trading intervals with high pool prices above $300/MWh was comparatively low. Figure 37 shows the trends observed in cap returns[41] in the NEM since 2000, illustrating reductions in volatility in New South Wales and Victoria.

**Figure 37 Historical cap returns in the NEM**



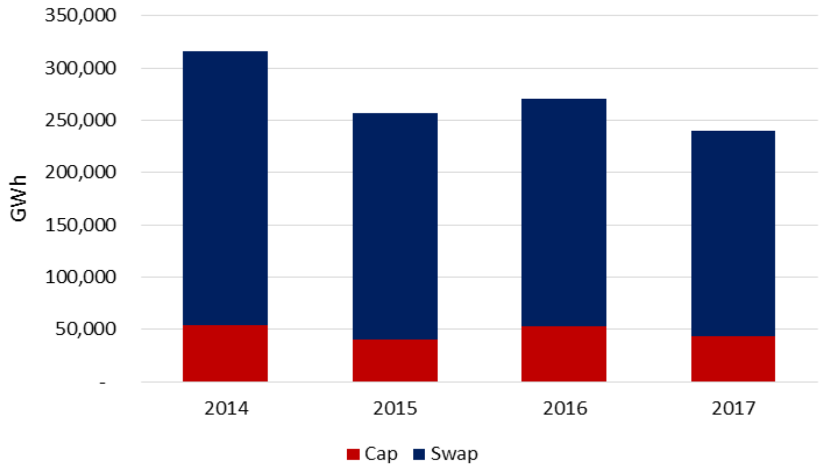

[41] Cap returns are indicative of market volatility. Higher cap returns indicate higher volatility.

# A1.4 Contract market liquidity

## A1.4.1 ASX futures liquidity

Figure 38 shows AEMO analysis of available ASX futures data. It highlights a material drop in overall liquidity (volume traded multiplied by MWh) of both swap and cap products traded since 2014 (-25% and -19% respectively).

**Figure 38 Traded futures volumes by product in the NEM since 2014**

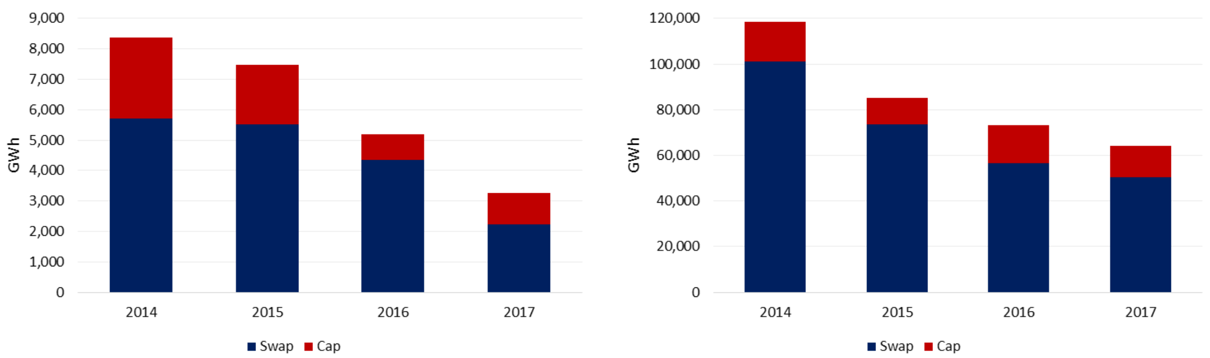



Note: ASX is the source for underlying data.

However, historical trends since 2014 show that this reduction has not been consistent in each NEM region or
by product:

- The largest reduction in ASX contract liquidity has been seen in South Australia, where swaps and caps have fallen 61% and 62% respectively (Figure 39 left hand side).
- New South Wales has also seen a large reduction in ASX swap and cap liquidity, down 50% and 21% respectively (Figure 39 right hand side).
- Swap liquidity in Queensland fell 19% and cap liquidity remained stable (rising 1%).
- Swap liquidity in Victoria rose 6% while cap liquidity fell 34%.

**Figure 39 Traded futures volumes by product in South Australia (LHS) and New South Wales (RHS) since 2014**




Note: ASX is the source for underlying data.

It is AEMO's view that these changes show a worrying trend of a market moving away from relying on the key elements that underpin the reliability frameworks. We offer the below case study of New South Wales to examine how market participant behaviour is impacting these frameworks.

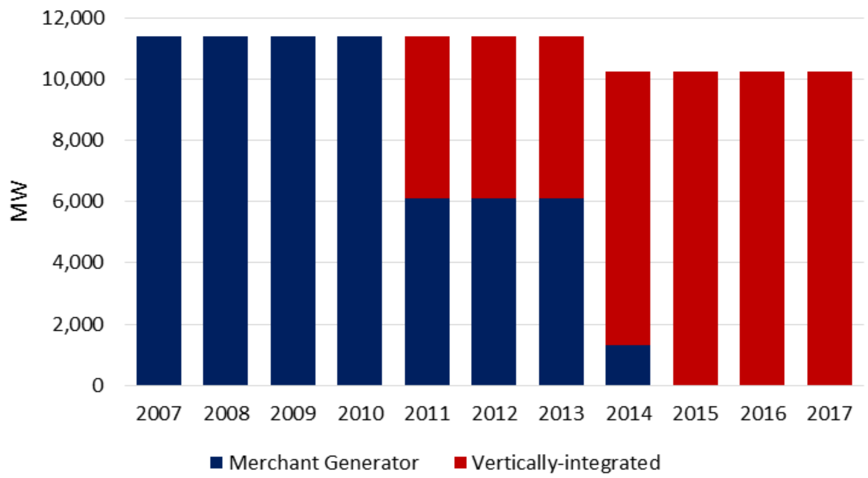
**Potential cause of declining liquidity: New South Wales case study**

Figure 39 shows a significant decline in the traded volumes of swaps and caps since 2014 in New South Wales. This fall followed the sale of state-owned merchant generators to the private sector in the state.

In 2014, the New South Wales Government sold Macquarie Generation (Liddell and Bayswater power stations) to AGL Energy. When combined with earlier sales of Eraring and Mt Piper to Origin Energy and EnergyAustralia respectively, New South Wales has seen a large proportion of generation move from merchant to vertically integrated 'gentailers' (see Figure 40).

This change in ownership is likely to have had an impact on liquidity in these markets over the subsequent years. A gentailer will typically seek to use its generation assets to cover its own exposure (via its retail book) to volatile wholesale electricity prices which reduces their need to participant in hedging markets. This in turn reduces the liquidity in these markets.

**Figure 40 Change over time in New South Wales black coal-fired power station ownership**



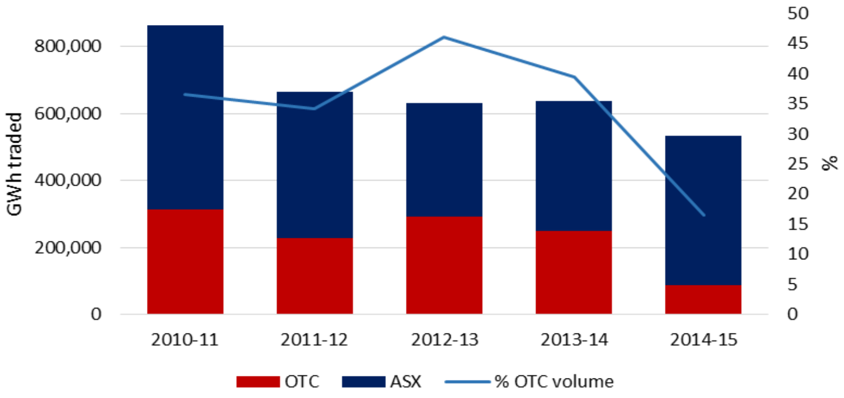

## A1.4.2 Over-the-counter contract market trends

Although there is little visibility of the volumes of OTC trades occurring, available information indicates that liquidity was declining at the same time as caps and swaps. The most up-to-date information on the number of OTC electricity derivatives traded is provided by Australia Financial Markets Association (AFMA) in its 2015 Australian Financial Markets Report (AFMR)[42]. The 2015 AFMR (Figure 41) shows that:

- The net volume of OTC gigawatt hours (GWh) traded decreased between 2010-11 and 2014-15.
- The proportion of OTC MWh traded compared to ASX Energy was decreasing.

[42] AFMA, 2015 Australian Financial Markets Report, available at https://afma.com.au/data/afmr/2015%20AFMR.pdf. AFMA collected this data via a survey sent out to its members until 2015.

**Figure 41** **Historic AFMA data on OTC and ASX GWh traded in the NEM**




While it is important to note that the AFMA survey relies on survey responses from members and so is not comprehensive, the data indicates that the reduction in futures liquidity seen in ASX Energy trades is most likely not due to the movement of volume from ASX to OTC. Rather, the data indicates a possible fundamental reduction in liquidity across all contacts.

### A1.4.3 The impact of declining liquidity on the market

The AEMC has stated that "a liquid contract market supports more efficient levels of reliability by lowering the cost of entry and exit"[43], while the Australian Energy Regulator (AER) said in its 2017 *State of the Energy Market Report* that "…reduced participation in contract markets reduces liquidity in those markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated"[44].

AEMO's view is that the reduction of contract liquidity observed in the NEM is hindering efficient levels of reliability by increasing the cost of entry and exit.

[43] AEMC. Reliability Frameworks Review *Interim Report*, p.84, available at https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review.

[44] AER. 2017 *State of the energy market*, p. 47, available at https://www.aer.gov.au/system/files/AER%20State%20of%20the%20energy%20market%202017%20-%20A4.pdf.

# A2. International learning

The energy transition is gaining momentum in power systems across the world. Transformations in response to increasing levels of VRE and DER are occurring at both ends of the electricity supply chain and to varying degrees in different power systems – each with unique technical, economic, and regulatory characteristics. A large body of work has been undertaken by key international agencies over the last year, including the IEA and IRENA. This section examines some of the findings of those studies.

A key theme is that the increasing levels of VRE and DER require increased flexibility to enable the system to
manage changing situations and short-term forecasting uncertainty. Jurisdictions around the globe are adjusting
their regulation and electricity market design to become more compatible with increasing penetrations of variable and small-scale generation.

## A2.1 IEA review of market designs to facilitate VRE

In 2017, the IEA prepared a major review of the challenges of integrating greater shares of VRE into the grid. Its *Getting Wind and Sun into the Grid* report[45] aimed to clarify the true challenges faced in early VRE deployment and signal policy solutions to resolve these issues. As every power system is unique, the IEA characterised the technical and policy challenges that systems need to address as they pass through each phase. The phases and issues are
described below:

- In Phase 1, the contribution of VRE is small and changes in output are comparable to the expected changes in demand. Although there are no noticeable impacts, a comprehensive assessment of the technical integration of the plant needs to be undertaken and the adequacy of grid codes needs to be assessed.
- A system enters Phase 2 when VRE starts to have a noticeable impact which only requires manageable adjustments to the system's operations. Areas like forecasting need greater attention, and grid connection codes need to consider international experience with an eye on improved disturbance performance, enabling VRE visibility, and curtailing. Planning needs to adjust to maximise the geographic distribution benefits of VRE and to ensure efficient transmission utilisation, and distribution and transmission interaction.
- Phase 3 is where VRE starts to have a more noticeable impact on the operation of the system overall, and individual plant, due to swings in the supply-demand balance. This phase requires reconsideration of market design, with a focus on ensuring the system's full potential capability for flexibility is made "fully available", to accommodate greater degrees of uncertainty and variability in the supply-demand balance.

  In this phase, changes are likely to be needed in the way conventional plant operates, and to market design. These changes should focus on ensuring there is sufficient dispatchable plant both in the system and available when needed. The capability of the transmission network requires consideration, and a consolidation of balancing areas may provide geographic and plant diversity benefits. Stronger coordination between distribution and transmission networks is likely to also be needed to manage reversed distribution network flows.
- A switch from reliability concerns to security concerns is expected in Phase 4. The ability to ensure security though system disturbances needs to be the focus here, as VRE may reach 100% of demand at some points in time (especially on low demand days). The point at which these issues arise is system-

[45] IEA, *Getting Wind and Sun into the Grid: A manual for policy makers*, 2017, available at https://www.iea.org/publications/insights/insightpublications/Getting_Wind_and_Sun.pdf.

specific, and may already have occurred in Phase 3. They can depend on engineering design decisions taken decades earlier, and will require a comprehensive engineering effort to understand for each system.

Importantly, the IEA acknowledged that the integration of VRE is manageable through these phases. Strong linkages between engineering and market design are required to understand present and future risks to system security and reliability and make adaptive changes ahead of time.

However, there are extents of VRE penetration that have not been explored, and for which there is no experience globally. Beyond Phase 4 the IEA has no strong recommendations, although inherent in their assessment is an expectation that those made previously are already completed:

- Phase 5 may be characterised by a "structural surplus" of VRE, and large volumes of curtailed energy, in the absence of increased short-term controllable demand (such as electric vehicles or heating) to balance generation.
- Phase 6 could introduce occasional periods of longer-lived shortfalls in supply, if geographic diversity of VRE is not sufficient. Here, energy conversion techniques (such as pumped storage, or chemical conversion to synthetic gas or hydrogen) need to be considered to provide longer-term support.

From this assessment, it is clear NEM regions generally reside between what the IEA would refer to as Phase 2 and Phase 4, where flexibility and system security need to be the focus. However, care should be taken in inferring that the NEM is already very flexible with its gross pool and 5-minute dispatch arrangements.

The NEM is unique in this regard, and much of the IEA's work is grounded in markets that have strong pre-dispatch commitment arrangements (either daily unit commitments, or capacity mechanisms). Thus, these markets are encouraged to introduce more intra-day trading. The IEA noted that obligations "to make generation capacity available in the short term to the greatest extent possible"[46] is best practice. The NEM's generally shallow pre-dispatch obligations do not reflect the level of commitment suggested by other markets.

## A2.2 IRENA review of market designs to facilitate VRE

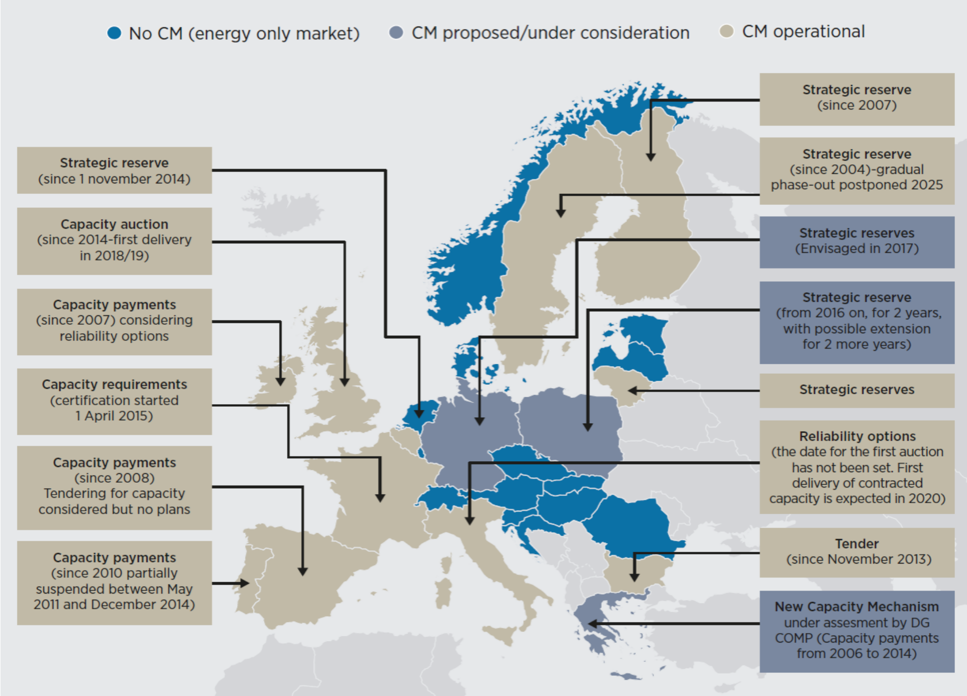
IRENA has also conducted a review[47] of market design with the intent of identifying policy and regulatory measures needed to accommodate high shares of distributed VRE. The review closely examined the contrast between European and US market designs.

It identified that many of the energy-only market designs in place in Europe have additional regulatory safeguards that are intended to ensure security of supply, and many of these markets have either already implemented, or are implementing, capacity markets (Figure 42).

[46] IEA, *Getting Wind and Sun into the Grid: A manual for policy makers*, 2017, p. 29.

[47] IRENA. *Adapting market design to high shares of variable renewable energy*, 2017, available at https://www.irena.org/publications/2017/May/Adapting-Market-Design-to-High-Shares-of-Variable-Renewable-Energy.

**Figure 42 European power systems with, or in the process of implementing, capacity mechanisms**




The IRENA review made a range of key recommendations for wholesale market design reforms:

- **Short-term markets** – focusing on the fundamental elements that facilitate market responses in fast-changing conditions associated with variable generation and demand response solutions.
  - Strengthening generator and demand response bids with an aim to understand the system's flexibility potential.
  - Reducing the time frames of short-term energy and reserve markets.
  - Increasing locational granularity of prices and dispatch schedules.
  - Greater co-optimisation of energy and reserves markets to ensure reserves are valued against what they provide to the system.
- **Balancing markets** – ensuring that all resources can participate in offering flexibility through balance markets.
- **Long-term investment signals** – to ensure market frameworks can incentivise development of adequate resources to maintain reliable supply in future, with particular reference to adequate generation capacity to be resilient to scarcity events.

## A2.3 Day-ahead market summary

The specific design of day-ahead markets varies widely across jurisdictions. There are, however, features common to all. For example, all markets are financially binding, although participation in the markets is mandatory in some and not others. (In this table, DA means day-ahead, RT indicates real-time, and CTRT means close to real time.)

**Table 5 Summary of day-ahead markets**

| Design element | ERCOT | CAISO | PJM | NEM | WEM* |
|---|---|---|---|---|---|
| Markets for supply adequacy | Energy-only | Energy + capacity | Energy + capacity | Energy-only | Energy + capacity |
| Short-term markets | • Day-ahead<br>• Real-time | • Day-ahead<br>• Hour-ahead | • Day-ahead<br>• Real-time | Real-time | • Day-ahead financial<br>• 2 Hour ahead (CTRT) |

| Design element | ERCOT | CAISO | PJM | NEM | WEM* |
|---|---|---|---|---|---|
| | | • 15-minute<br>• 5-minute | | | |
| Supply side participation | • DA: voluntary<br>• RT: mandatory | • Mandatory (DA and RT) | • Mandatory for supply with a capacity award,<br>• Voluntary for others (DA and RT) | Mandatory | • Mandatory for supply with a capacity award,<br>• Voluntary for others (DA and CTRT) |
| Demand side participation | • DA: voluntary<br>• RT: option for dispatchable bids | • DA: voluntary<br>• RT: CAISO load forecast | • DA: voluntary<br>• RT: fixed MW amount based on PJM forecast | Voluntary | Mandatory CTRT for providers with a capacity award |
| Unit commitment | Self-commitment and centralised unit commitment | • Self-commitment<br>• Day-ahead unit commitment, and intraday reliability unit commitment process | Self-commitment and centralised unit commitment | Self-commitment (optional central commitment for fast start plant) | Self-commitment |
| Offer structure | • 3-part offers or<br>• 1-part offer | 2-part offers | • 3-part offers (generation)<br>• 2-part offers (demand response) | Energy offer curve | Energy offer curve |
| Pre-dispatch and reliability processes | Day-ahead and intra-day reliability unit commitment | 1-hour look-ahead unit commitment and dispatch every 5/15 minutes with multi-interval optimisation, integrated with short-term markets | • Day-ahead and intra-day reliability unit commitment<br>• 2-hour look-ahead dispatch and unit commitment with multi-interval optimisation integrated with real-time market | • PASA processes (2-year, 1-week, pre-dispatch)<br>• Pre-dispatch<br>• AEMO interventions | • PASA processes (3 years, 3 weeks)<br>• Energy market pre-dispatch (limited relative to NEM)<br>• AEMO interventions<br>• Central generator outage scheduling |
| Strategic reserves | Standing reserves procured annually to USD 50 million (emergency response service) | Covered by capacity mechanism | Covered by capacity mechanism | RERT (10 weeks out) | Covered by capacity mechanism |

* In the WEM's Reserve Capacity Mechanism (RCM), the capacity valuation methodology for VRE generation considers the contribution that these facilities make to power system reliability at times of greatest reliability risk. The capacity valuation uses observed output in these high-risk periods and applies discount factors to account for the degree of variability, providing incentives for VRE generators to reduce variability. The methodology implicitly values diversity of VRE resources by focusing on times when demand for dispatchable capacity is at its highest, rather than simply focusing on high demand periods.

# A3. Risks of non-supply

As discussed in this paper, the make-up and operating complexity of the NEM has increased and is changing at an increasingly rapid pace, for a number of reasons. These factors include:

- A growing proportion of VRE generation (on-grid and behind the meter).
- An aging fleet of thermal generation.
- The ongoing need for adequate fuel supplies.
- Increasing temperatures and frequency of heatwave events.

The traditional model of calculating expected USE, as defined in the Rules, is to undertake a probabilistic assessment of possible market outcomes that covers a range of different variables including demand levels, generator availability/outages, and other factors. USE risks will therefore be higher than this expectation during extreme peak conditions, and/or when real time supply and demand conditions are worse than assumed in the modelling, such as higher generator outages.

The analysis may show sufficient resources to meet the reliability standard while simultaneously showing a high risk of insufficient supply to meet demand under more extreme, but still plausible, future conditions. Involuntary load shedding, during an event where there was not an obvious cause, does not appear to meet community expectations.

Considering this, there is an urgent need for an operating peak reliability standard so AEMO is equipped with the tools and market frameworks to operate a secure and reliable system at the lowest cost.

Further, AEMO is reconsidering how it implements the current reliability standard and reports operational and economic information to assist planning, to ensure the future scarcity risks are adequately captured. Such information can be provided in future ESOOs.

## A3.1 The NEM planning reliability standard and AEMO's implementation

The planning reliability standard, as defined in the Rules (clause 3.9.3C), is a maximum expected USE in a region of 0.002% of the total energy demanded in that region for a given financial year. This standard is set by the AEMC and reviewed by the Reliability Panel every four years. It represents a trade-off, made on behalf of consumers, between the price paid for electricity and the cost of not having it when it is needed. It has been in place since market start and the Reliability Panel is currently not proposing any changes to the standard as a consequence of its 2018 Reliability Standard Settings Review (RSSR).

AEMO, in consultation with industry, is required to publish the reliability standard implementation guidelines (RSIG) which set out how AEMO seeks to implement the reliability standard. Table 6 below shows a summary of processes used by AEMO to implement the standard across the various study timeframes.

**Table 6 How AEMO implements the reliability standard**

| Process | Study timeframe/ publication frequency | Reliability assessment method | Assumptions for potential breach of reliability standard |
|---|---|---|---|
| ESOO | 10 year/Annually | USE | Forecast USE>0.002% of energy consumption in any forecast year |
| Energy Adequacy Assessment Projection (EAAP) | 2 year/Annually | USE | Forecast USE>0.002% of energy consumption in any forecast year |

| | | | |
|---|---|---|---|
| Medium Term Projected Assessment of System Adequacy (MT PASA) | 2 year/Weekly | USE and daily LOLP | Forecast USE>0.002% of energy consumption in any forecast year |
| Short Term Projected Assessment of System Adequacy (ST PASA) | 6 day/2 hours | Capacity | Lack of Reserve (LOR) 2 (risk of load shedding for worse case contingency event) or LOR3 (immediate risk of load shedding due to lack of supply) |

The NEM reliability standard is stated as a maximum expected USE level, meaning a statistical expectation of a future state. It is an average across a range of future outcomes, weighted for probability of occurrence.

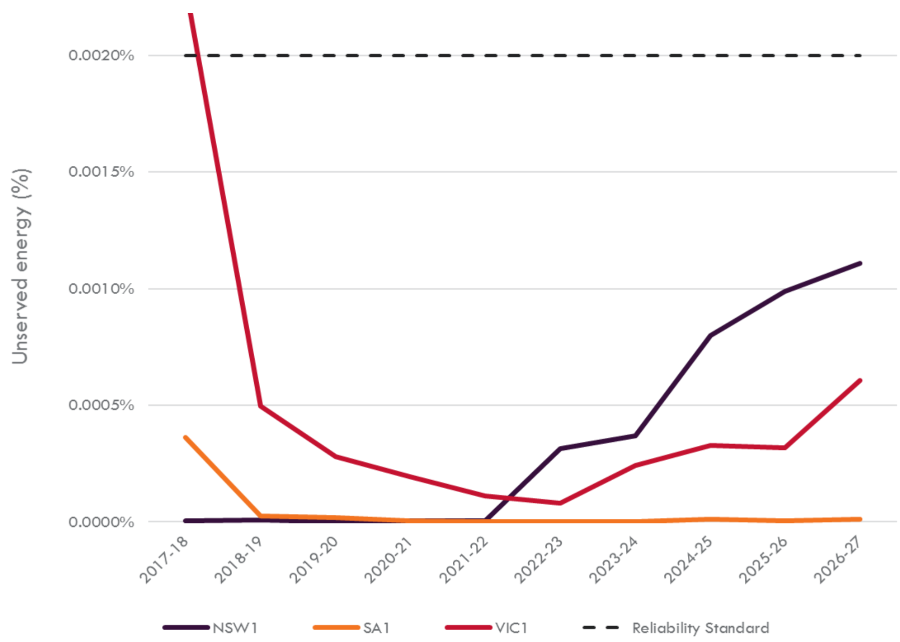
The expected USE is calculated in the NEM based on Monte Carlo simulations of supply adequacy, using a number of historical reference years to scale forecast demand as well as wind and solar generation, and model random thermal unit outages based on outage rates derived from historical performance data.

A probabilistic approach is needed because the majority of scarcity events are typically triggered by circumstances that reflect a combination of extreme weather-related loads or VRE availability, and unusual combinations of generation outages. In the short term (next six days) these occurrences are easier to predict given the prevailing system and weather conditions, whereas over the two- to ten-year timeframe, these assumptions are highly uncertain.

Given that the planning reliability standard is a statistical expectation, the actual occurrence of load shedding in a given year could be much higher (or lower) than the expected level. This is demonstrated in the probabilistic analysis of the reliability of supply in New South Wales completed to assess the impact of Liddell's closure.

Figure 43 shows the USE modelled over the next ten years, considering only existing and committed new generation and shows that the reliability standard of 0.002% USE is not forecast to breached, even after Liddell's closure in 2022. This is against expectations, and has been examined using a range of other measures to demonstrate the reliability actually delivered.

**Figure 43 Assessing supply adequacy against the reliability standard**

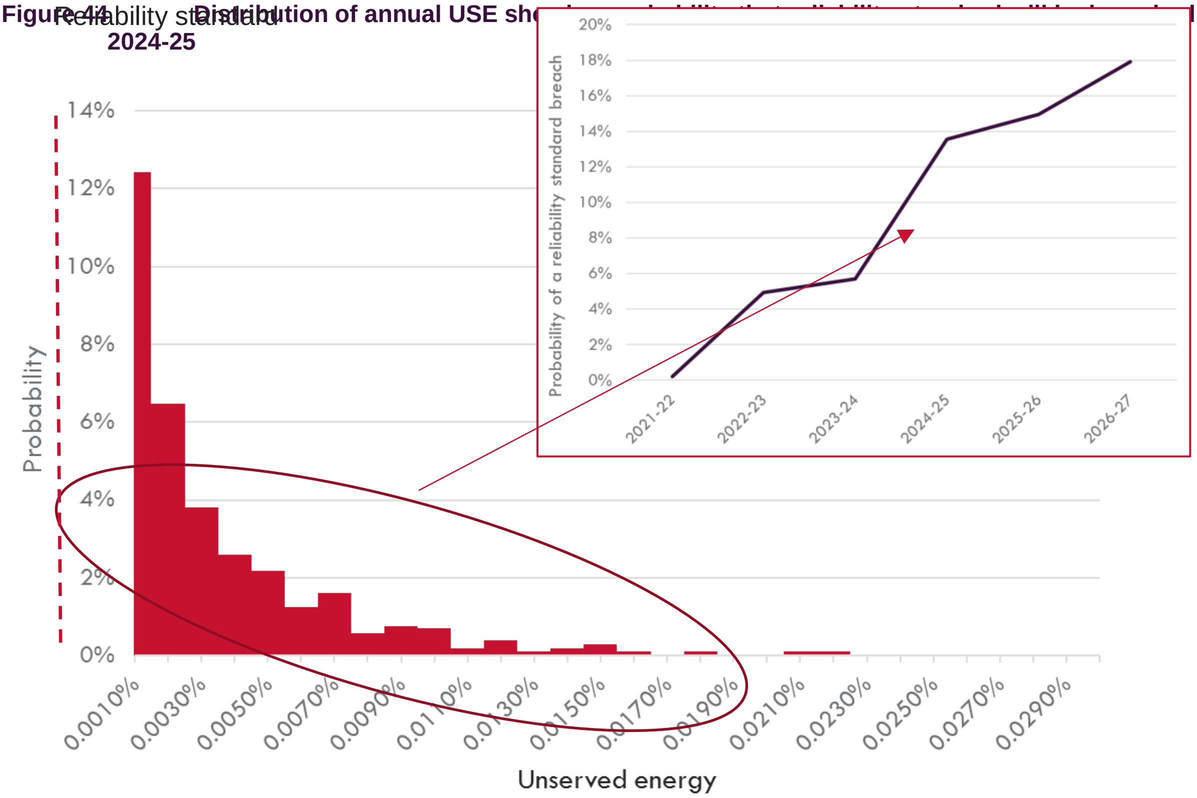



The histogram in Figure 44 below shows the range of annual USE outcomes observed from the Monte Carlo simulations, weighted for probability, for New South Wales in 2024-25. The x-axis shows the USE calculated as
a percentage of annual consumption, and the y-axis shows how frequently that level of USE was observed

in
the simulations.

There is a long tail to the distribution of observed USE, primarily due to the occurrence of multiple outages or low VRE availability at times of peak demand. Although on expectation New South Wales is within the reliability standard, there is an increasing likelihood that annual USE would exceed the standard. As shown, there are circumstances where the level of USE could be ten times greater than the expected maximum (that is, 0.02% rather than 0.002% USE).

**Figure 44 Distribution of annual USE sh[illegible], 2024-25**




Not shown are the 65% of simulations where no USE was observed, typically under milder summer temperatures.

An alternate measure of reliability is the probability of a loss of load event (LOLP). Figure 45 shows the LOLP for New South Wales over the same period, extracted from the same modelling. This demonstrates a high risk of load shedding, despite meeting the USE standard. Further analysis of the results shows that load shedding is almost certain with a 10% POE event, as shown in Figure 46.

**Figure 45** Probability of load shedding under weighted 50% POE and 10% POE demand conditions

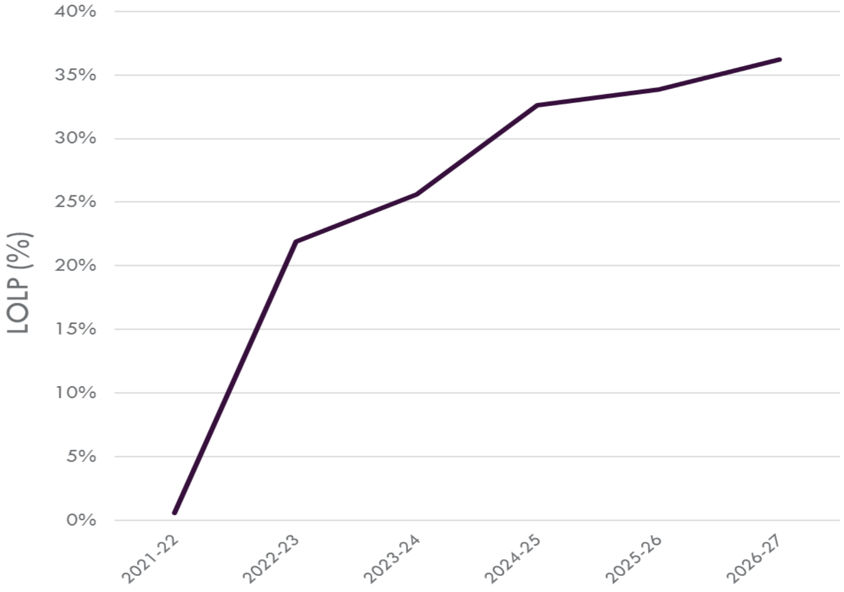
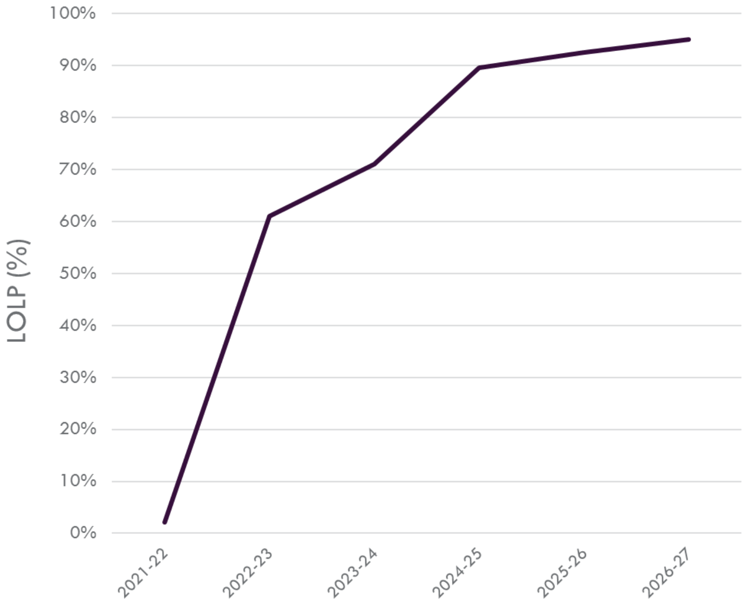



**Figure 46** Probability of load shedding under 10% POE demand conditions only

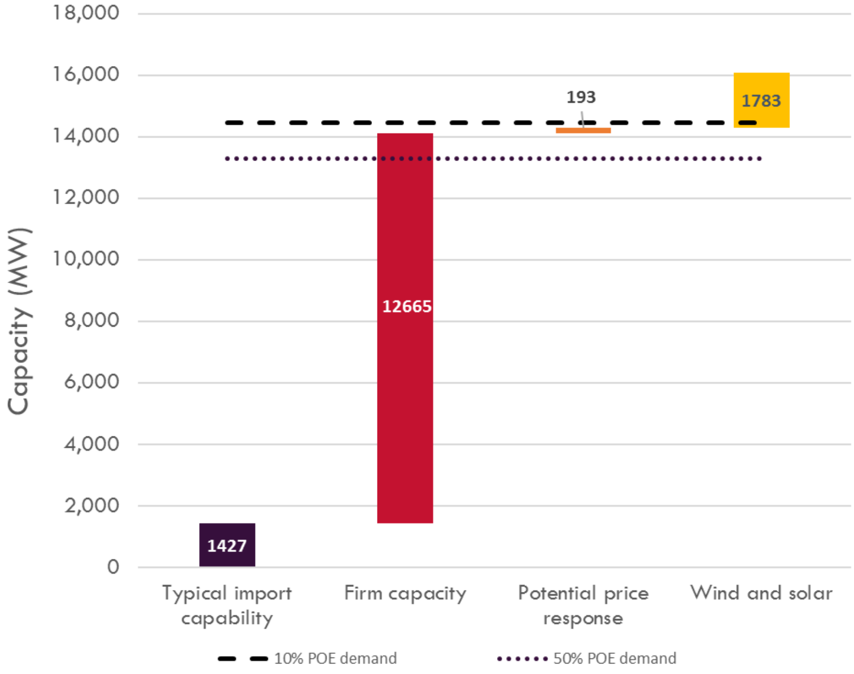



As shown in Figure 47, analysis of existing and committed capacity and import in New South Wales after the Liddell closure shows why the risk of USE is so high during a 1-in-10 year demand event. Under these demand conditions, even with all firm generation (excluding wind and solar) fully available in New South Wales, AEMO would still expect to rely on:

- Maximum interconnector support into New South Wales (primarily from Queensland), totalling around 1,500 MW.
- 200 MW of voluntary demand side participation.
- Around 150 MW of wind/solar (out of a projected total capacity of 1.8 GW).

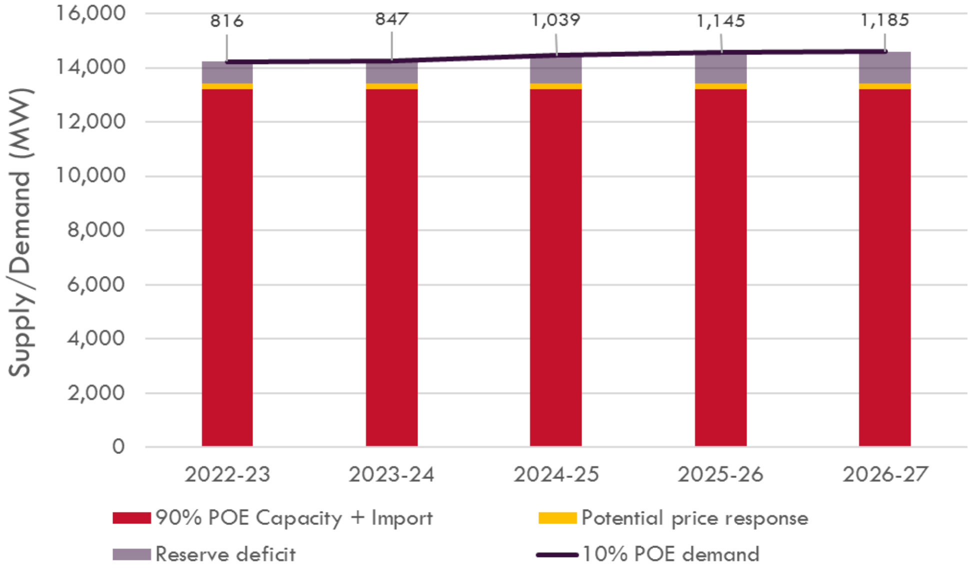
Clearly, under these conditions, unplanned loss of one or more local generators would result in almost inevitable load shedding unless windy conditions prevailed.

**Figure 47** **Supply composition at times of 10% POE peak demand in New South Wales in 2024-25**




As shown in Figure 48, analysis of the 90% POE supply adequacy (that is, the minimum level of local generation and imports expected to be available 90% of the time) in New South Wales at times of peak demonstrates that the region would be up to 1,185 MW short of meeting a 1-in-10-year peak demand without any additional capacity to replace Liddell (over and above what is already committed). This additional capacity would provide reasonable confidence that the 1-in-10-year peak demand could be met 90% of the time, roughly equivalent to achieving <5% weighted LOLP assessed over an entire year.

**Figure 48** **Estimate of reserve deficit assuming 10% POE demand should be met 90% of the time**




Alternatively, additional dispatchable capacity of around 850 MW would provide reasonable confidence that the
1-in-10-year peak demand could be met 90% of the time, roughly equivalent to achieving 10% weighted LOLP assessed over an entire year.

While this type of assessment provides a simple and tangible level of capacity reserve required that may support development of an operational reliability standard, it should be noted that it is more challenging to calculate when reliability in a region is heavily influenced by reserves in a neighbouring region, such as Victoria and South Australia.

## A3.2 Why is this becoming more of a problem?

The changing demand profile (discussed in Section 1.2) and weather and climate impacts (discussed in Section (1.3) are factors in AEMO's modelling showing low USE despite a high probability of outages. Also, as noted in Section 2.1:

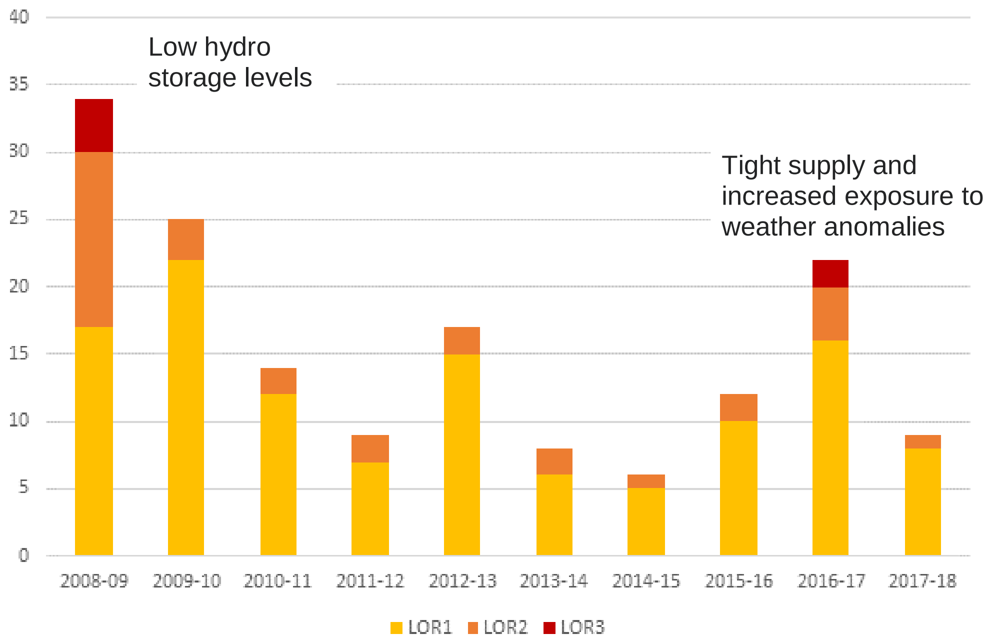
- The impact of outages is likely to become more widespread, affecting more households over the most extreme
heat period.
- The USE measure is becoming more sensitive to 10% POE demand conditions, and weather-driven variations in input assumptions more generally. With increasing growth in variable renewable energy resources, both demand and supply are now exposed to the vagaries of weather, such as wind and solar availability, impacting AEMO's ability to meet demand on extreme peak days. This leads to greater uncertainty, and the longer tail in the USE distribution shown in Figure 44.

Examination of historical LOR conditions further highlights the increasing influence of weather on the power system – both as a fuel source, and through climate change.

LOR notices are issued by AEMO to indicate to market participants a tightening in available supply reserves, with notices increasing from LOR1 to LOR3 to give clear signals that the system is approaching closer to a point where AEMO, as operator, would need to shed load to avoid system loss.

In Figure 49 below, the number of LOR notices issued by AEMO over the past decade indicates an increase in the incidence of LOR2 and LOR3 conditions being observed, consistent with the tighter supplies and increased exposure to weather anomalies over this period.

**Figure 49 History of LOR notices, 2008-09 to 2017-18 (year to date)**




Note: This figure uses the history of Market Notices of LORs being issued, which is similar to how the Australian Energy Market Commission (AEMC) has counted LORs in reporting market performance. The count does not exactly match the number of times LOR conditions have existed, but it shows the same trend and also enables us to go as far back as 2008-09.

While demand peaks have always been uncertain, and likely to vary according to the weather, the power system must now also manage increased uncertainty and variability of supply.