REVIEW

Australian Energy Market Commission

# ISSUES PAPER

## Reliability Frameworks Review

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Issues paper

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**About the AEMC**

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

# Executive summary

Over the past year, load shedding events on low reserve days, pre-emptive action and announcements from jurisdictional governments, as well as recommendations made by the Finkel Panel in the *Independent Review into the Future Security of the National Electricity Market* have led to a greater focus on reliability in the National Electricity Market (NEM).

Meanwhile, the NEM is changing at a rapid pace on both the demand and the supply side. On the demand side, falling technology costs and the uptake of distributed energy resources are changing how consumers interact with the energy sector. On the supply side, ongoing trends such as the retirement of thermal generation and increasing penetration of variable, renewable generation are having implications for the market generally, and for reliability in particular.

The Australian Energy Market Commission (AEMC or Commission) considers it is timely to assess whether the current market and regulatory reliability frameworks can make sure that consumers receive a reliable supply of energy. It has therefore initiated a review into the market and regulatory frameworks relating to reliability.

A “reliable power system” has enough generation, demand-side and network capacity to supply customers with the energy that they demand with a very high degree of confidence. This requires several elements: efficient investment, retirement and operational decisions by market participants (on both the supply and demand side) resulting in an adequate supply of dispatchable capacity, reliable transmission and distribution networks and a secure system.

This review is focussing specifically on one of these elements: the efficient investment, retirement and operational decisions by market participants.

## Reliability in the NEM is market based

The regulatory framework for reliability in the NEM is primarily market based. However, additional supplementary mechanisms also exist that allow for interventions to be made in certain limited circumstances when the market based arrangements have not – or will not – deliver the desired outcome.

Decisions about dispatchable capacity are made in response to price signals and incentives offered by the spot and contract markets. The contract market has been an integral part of the NEM market design since its inception and makes a major contribution to reliability. Contracts exist to hedge uncertainty and manage risk, although participants can also achieve this by creating “natural hedges” through vertical integration, i.e., combining retailing and generation within one business.

Participants make investment, retirement, operation and maintenance decisions on the basis of expectations of future spot prices provided by the contract market and the need for investment in new capacity to enter into contracts (or natural hedges) to reduce exposure to future price risk. These types of decisions underpin reliability in the NEM.

In a perfectly competitive market, contract and spot price signals would be sufficient by themselves to deliver an efficient level of reliability. But, of course, the strict conditions that underpin the theoretical construct of perfect competition rarely exist in “real world” markets – and the NEM is no exception. Consequently, the National Electricity Rules (NER) set limits on the extent to which wholesale prices can rise and fall. These are part of the reliability standard and settings, which are recommended by the Reliability Panel.

Australian Energy Market Operator (AEMO) uses the reliability standard to forecast the potential for unserved energy (the amount of energy that is required by customers but cannot be supplied). The outcomes of AEMO's forecasts then serve as a signal to the market that it should deliver enough capacity to meet a certain level of reliability, to avoid expected unserved energy. The standard is underpinned by the four reliability price settings, namely: the market price cap, the cumulative price threshold, the administered price cap, and the market floor price.

Currently, the reliability standard is set at 0.002 per cent expected unserved energy, that is, that at least 99.998 per cent of annual demand for electricity is expected to be supplied. In considering the appropriate level of the standard, the Reliability Panel has regard to the costs associated with higher reliability and the costs of unserved energy. Having the standard set at this level reflects the fact that the most efficient level of reliability is not 0 per cent unserved energy. Such an approach would be inefficient: the cost of the provision of a supply of energy at all times would exceed the value placed on it by consumers, given this value is not a constant and varies over time and with the duration and frequency of interruptions.

Despite the fact that the reliability framework is based around market-driven investment and operational decisions, it also provides AEMO with the ability to intervene in the market to address potential shortfalls of supply, in those limited circumstances where the market does not – or is not expected to – deliver the desired outcomes.

In the first instance, these intervention mechanisms are designed to elicit a market response, i.e., to provide further impetus to participants to produce the outcome that should ideally have arisen absent the intervention. However, if that response is not forthcoming, or inadequate, AEMO can then intervene directly to minimise the need for involuntary load shedding.

The main intervention mechanisms are the Reliability and Emergency Reserve Trader (RERT) provisions, which allows AEMO to contract for additional reserves, directions (for example, AEMO directing a generator to increase output) and clause 4.8.9 instructions (for example, AEMO instructing a transmission network service provider to shed customer load).

## Project scope

This Review will consider what changes to existing regulatory and market frameworks are necessary to provide an adequate amount of dispatchable capacity in the NEM to meet the reliability standard. This involves longer-term considerations such as having the right amount of investment, as well as shorter-term operational considerations to make sure an adequate supply is available at a particular point in time. To deliver a reliable supply to consumers it is necessary to always have the level of supply to be greater than current demand to allow for unexpected changes. This margin of supply over demand is termed 'reserves', and essentially acts to deal with unexpected developments.

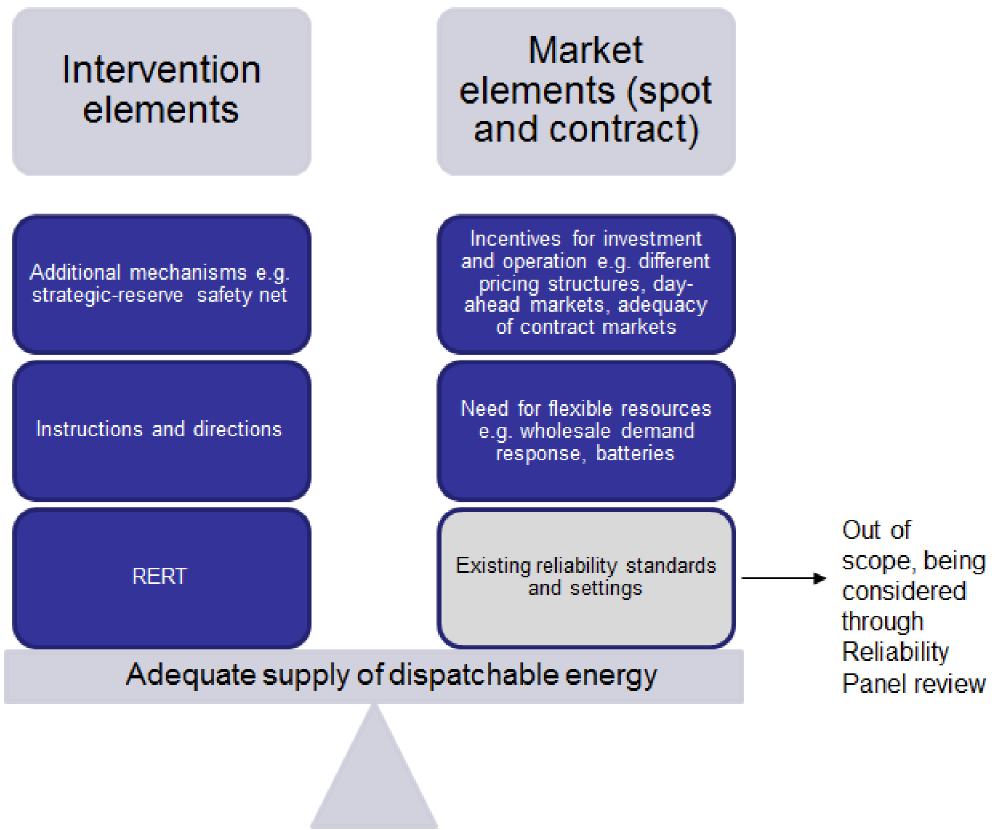
The *existing* reliability standard and settings are outside of the scope of this Review since they are currently being considered in the Reliability Panel's *Reliability standard and settings review*.[1] The AEMC will work closely with the Reliability Panel and the findings from that piece of work, where relevant, will inform this Review. For example if the Reliability Panel's analysis suggests it is necessary to do so, this Review will also assess whether there are any other fundamental changes that could be made to the reliability settings or additional structures that could provide superior price signals when there are shortfalls of reserves to incentivise more efficient investment and operation decisions.[2]

The Review will examine the regulatory and market frameworks associated with reliability in a holistic manner, and in the context of the NEM's existing industry structure and drivers of reliability frameworks. It will identify any changes to the current reliability frameworks needed to facilitate the efficient investment, retirement, operation and maintenance decisions that are required to produce an adequate supply of dispatchable capacity, given the current and expected environmental policy mechanisms.

1 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018.

2 The reliability of transmission and distribution networks is also outside of the scope of this Review.

**Figure 1 Scope of the Review**




In addition to assessing the existing mechanisms for delivering an adequate supply of dispatchable capacity, the Review will also consider how to better incorporate variable renewable energy in the NEM, including:

- how existing variable generation could be made firmer (that is, dispatchable) in the future
- how, and what, mechanisms could be used to incentivise efficient investment, retirement and operational decisions that result in sufficient dispatchable capacity being present in each region at any particular time.

The Commission will also incorporate, and be informed by, any existing work or recommendations that relate to reliability, including recommendations from the Finkel Panel that are within the scope of the Review, such as:[3]

- the recommendation of a Generator Reliability Obligation

3 The Commission also notes that one of the other recommendations was a requirement for all large generators to provide at least three years' notice prior to closure. AEMO should also maintain and publish a register of long-term expected closure dates for large generators. The Commission notes that this recommendation is, in part, related to information requirements about reliability, and so will also consider this recommendation to the extent it has not otherwise been further progressed or implemented in other workstreams.

- the need for a strategic reserve to act as a safety net in exceptional circumstances as an enhancement or replacement to the existing reliability and emergency reserve trader (RERT) mechanism

- the suitability of a 'day-ahead' market

- a mechanism that facilitates efficient demand response in the wholesale energy market.

The Review will also take into account any relevant AEMO workstreams, including learnings from existing initiatives such as the demand response pilot program[4] being trialled by Australian Renewable Energy Agency (ARENA) and AEMO, and any other trials that ARENA and AEMO may undertake through their MOU that are relevant to reliability.

In addition, AEMO is currently preparing advice for the Commonwealth Government on the adequacy of dispatchable generation in the NEM. This will further inform the assessment of the issues, as well as potential solutions, and we will work closely with AEMO on this.

## Purpose of this paper and stakeholder consultation

This Issues Paper elaborates upon the key features of the existing reliability framework summarised above. It also discusses the potential issues associated with the current market-based and intervention aspects of the reliability framework, as well as other related aspects of reliability, which will be examined in more detail as the Review progresses.

The Commission invites stakeholder submissions on the potential issues raised. Submissions are due on **19 September 2017.**

The Commission also encourages stakeholders that wish to have meetings regarding this Review to contact us. Stakeholders wishing to meet with the AEMC should contact Sarah-Jane Derby on 02 8296 7823 or sarah.derby@aemc.gov.au.

4 The initiative is a three-year pilot program seeking to provide 160 MW of reserve capacity through demand response. Those successfully enrolled in the program will join AEMO's short notice RERT panel and AEMO would call upon them if operating reserves in the NEM fall to critically low levels. The pilot is essentially a trial of demand response as a reliability mechanism. More information about the pilot program may be found here: https://arena.gov.au/funding/programs/advancing-renewablesprogram/demandresponse/.

# Contents

# 1 Introduction

On 11 July 2017, the Australian Energy Market Commission (AEMC or Commission) initiated a review into the market and regulatory frameworks necessary to support the reliability of the electricity system.[5]

## 1.1 Purpose of the Review

Over the past year, load shedding events on low reserve[6] days, pre-emptive action and announcements from jurisdictional governments, as well as recommendations made by the Finkel Panel in the *Independent Review into the Future Security of the National Electricity Market* have led to a greater focus on reliability in the National Electricity Market (NEM). Australian Energy Market Operator (AEMO)'s latest Energy Supply Outlook publication concluded that:[7]

> "*AEMO expects all NEM regions will meet the reliability standard set in the NER over the next two years based on the generation and storage expected to be available. There is, however, still a risk of electricity supply falling short of demand, especially in extreme conditions… South Australia is considered most at risk of breaching the reliability standard.*"

The AEMC therefore considers that it is timely to assess whether the current market and regulatory reliability frameworks are appropriate given the above developments, as well as other current drivers of change that affect reliability, including a changing generation technology mix such as increased penetration of renewable generation as well as batteries, and greater opportunities for demand-side participation through increased uptake of distributed energy resources.

This Review will provide recommendations to the COAG Energy Council on any changes required to the regulatory and market frameworks to make sure that the existing high performance relating to reliability in the NEM continues to occur, as the electricity system transforms.

## 1.2 Background to the Review

A "reliable power system" has enough generation, demand-side and network capacity to supply customers with the energy that they demand with a very high degree of confidence. This requires several elements:

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5 The review was initiated by the AEMC under section 45 of the NEL. Regulatory frameworks refer to the National Electricity Rules and the National Electricity Law.

6 Reserve level is a concept defined in the NER. Specifically, capacity reserve, defined in NER Chapter 10 as: At any time, the amount of surplus or unused generating capacity indicated by the relevant Generators as being available in the relevant timeframe minus the capacity requirement to meet the current forecast load demand, taking into account the known or historical levels of demand management.

7 AEMO, Energy Supply Outlook, June 2017, p. 3.

- efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of dispatchable capacity
- a reliable transmission network
- a reliable distribution network, as well as
- the system being in a secure operating state, that is, one where the power system is in, or can be returned to a satisfactory operating state within 30 minutes.

As a result, a reliable supply of electricity to customers requires adequate network planning, generation capacity availability, maintenance of all parts of the electricity supply chain and a properly functioning market (as investment in reliability is driven by the market).

**Reliability** is distinct from **system security**:

- A secure system is one that is able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Security events are caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits, such as voltage and frequency.
- By contrast, a reliable system is one with enough energy and network capacity to supply customers.

While the two concepts are separate, they are closely related operationally. A reliable power system is also a secure power system. However, the converse is not necessarily true; a power system can be secure even when it is not reliable. For example, the NER allows AEMO to undertake involuntary load shedding, potentially compromising reliability, in order to return the power system to a secure operating state.

The Commission is considering system security through its *System security work program*, which is further detailed on our website.[8]

## 1.3 Project scope

This Review will consider what changes to existing regulatory and market frameworks are necessary to provide an adequate amount of dispatchable capacity in the NEM to meet the reliability standard. This involves longer-term considerations such as having the right amount of investment, as well as short-term operational considerations to make sure an adequate supply is available at a particular point in time.

It is also important to note that the Review is focussed on both the *supply* of dispatchable capacity (that is, generation) as well as the *demand-side* (for example, demand response).

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8 See: http://www.aemc.gov.au/Major-Pages/System-Security-Review.

The reliability of transmission and distribution networks is outside of the scope of this Review.[9]

The *existing* reliability standard and settings are also outside of the scope of this Review since they are currently being considered in the Reliability Panel *Reliability standard and settings review*.[10] The AEMC will work closely with the Reliability Panel and the findings from that piece of work, where relevant, will inform this Review.

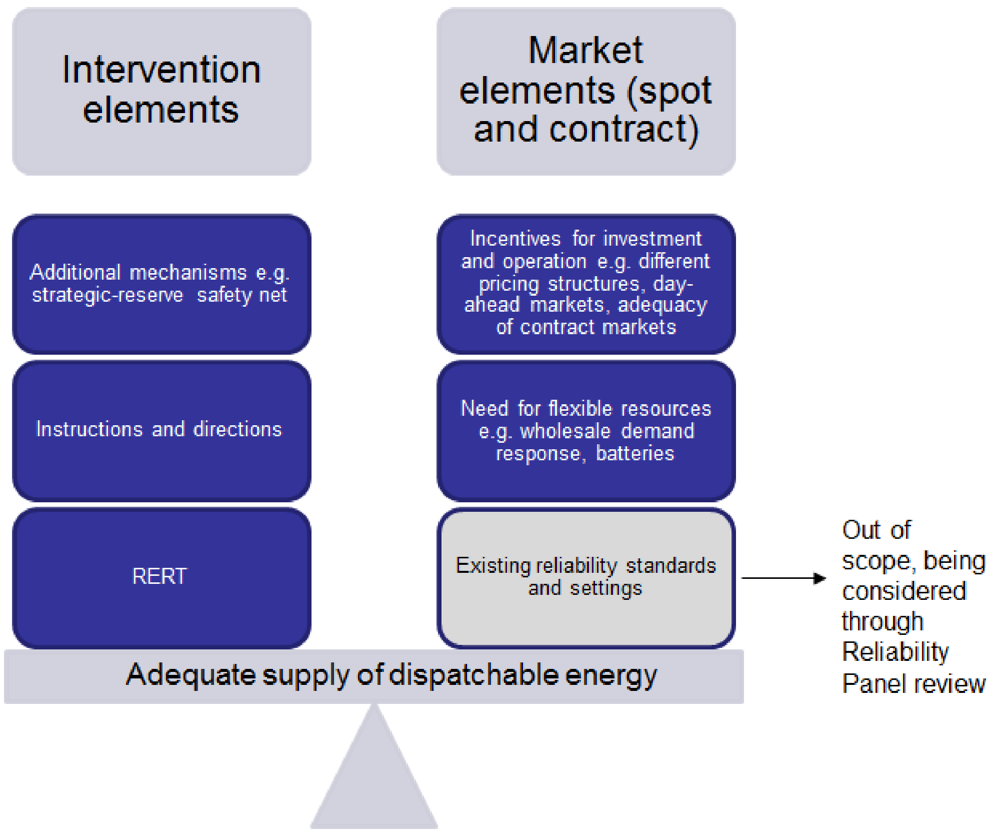
The Review will assess both existing, as well as potentially new, market and intervention elements of the reliability framework, as shown in Figure 1.1, as well as considering how these elements could address reliability in both the short- and long-term.

The Review will examine the regulatory and market frameworks associated with reliability in a holistic manner, and in the context of the NEM's existing industry structure and drivers of reliability frameworks. It will identify any changes to the current reliability frameworks needed to facilitate the efficient investment, retirement, operation and maintenance decisions that are required to produce an adequate supply of dispatchable capacity, given the current and expected environmental policy mechanisms.

9 Each state and territory government retains control over how transmission and distribution reliability is regulated and the level of reliability that must be provided. Investments in transmission and distribution networks are ongoing and involve a trade-off between the cost of building and maintaining the networks and the value placed on reliability by customers.

10 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018.

**Figure 1.1 Scope of the Review**




In addition to assessing the existing mechanisms for delivering an adequate supply of dispatchable capacity, the Review will also consider how to better incorporate variable renewable energy in the NEM, including:

- how existing variable generation (otherwise known as intermittent generation) could be made firmer (that is, dispatchable) in the future
- how, and what, mechanisms could be used to make sure there is efficient investment, disinvestment and operational decisions resulting in sufficient dispatchable capacity present in each region at a particular point in time.

If the Reliability Panel's analysis in the *Reliability standard and settings review* suggests it is necessary to do so, this Review will also assess whether there are any other fundamental changes that could be made to the reliability price settings that could provide superior price signals when there are shortfalls of reserves to incentivise more efficient investment, retirement and operational decisions.

The Commission will also incorporate, and be informed by, any existing work or recommendations that relate to reliability, including recommendations from the Finkel Panel that are within the scope of the Review, such as:[11]

11 The Commission also notes that one of the other recommendations was a requirement for all large generators to provide at least three years' notice prior to closure. AEMO should also maintain and publish a register of long-term expected closure dates for large generators. The Commission notes

- the recommendation of a Generator Reliability Obligation
- the need for a strategic reserve to act as a safety net in exceptional circumstances as an enhancement or replacement to the existing reliability and emergency reserve trader (RERT) mechanism
- the suitability of a 'day-ahead' market
- a mechanism that facilitates efficient demand response in the wholesale energy market.

The Review will also take into account any relevant AEMO workstreams, including learnings from existing initiatives such as the demand response pilot program[12] being trialled by Australian Renewable Energy Agency (ARENA) and AEMO, and any other trials that ARENA and AEMO may undertake through their MOU that are relevant to reliability.

In addition, AEMO is currently preparing advice for the Commonwealth Government on the adequacy of dispatchable generation in the NEM. This will further inform our assessment of the issues, as well as potential solutions to these issues, and we are working closely with AEMO on this.

## 1.4 Related work

This Review forms part of a broader reliability work program being undertaken by the AEMC.

As mentioned, the Reliability Panel's *Reliability standard and settings review* is considering whether the standard and settings remain suitable to guide efficient investment in the power system to meet consumer demand for energy, while protecting market participants from substantial risks that threaten the overall stability and integrity of the market.

In addition, on 1 August 2017, the AEMC received a rule change request from AEMO related to reliability in the NEM.[13] AEMO considers that the current lack of reserve (LOR) declaration framework, currently based on the concept of credible contingencies, is no longer appropriate for identifying risks in the power system, and so it wishes to replace them with a system triggered by a wider range of risks than those presently allowed for.

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that this recommendation is, in part, related to information requirements about reliability, and so will also consider this recommendation to the extent it has not otherwise been further progressed or implemented in other workstreams.

12 The initiative is a three-year pilot program seeking to provide 160 MW of reserve capacity through demand response. Those successfully enrolled in the program will join AEMO's short notice RERT panel and AEMO would call upon them if operating reserves in the NEM fall to critically low levels. The pilot is essentially a trial of demand response as a reliability mechanism. More information about the pilot program may be found here: https://arena.gov.au/funding/programs/advancing-renewablesprogram/demandresponse/.

The AEMC is expecting further rule changes related to reliability from AEMO shortly.

The Review will be progressed concurrently and in coordination with the assessment of these rule change requests. Any forums, meetings and workshops held as part of the Review may also be used to progress the assessment of the rule change requests, subject to the statutory rule change process requirements being met.

In addition, the Commission is also recently commenced Stage 2 of the *Reporting on drivers of change that impact transmission frameworks* review. This review is considering issues, and options to address those issues, associated with the coordination of generation and investment in the NEM. Potentially, outcomes from that review will contribute towards reliability outcomes in the NEM. That review will also be progressed in coordination with this piece of work.

## 1.5 Consultation process and submissions

The AEMC intends to consult broadly in conducting this Review. Stakeholders will have a range of opportunities to be involved in the Review, as detailed below.

### 1.5.1 Reference group and working group

A Reference Group comprising senior representatives of the AEMC, AEMO, the Reliability Panel, the Australian Energy Regulator (AER), the Senior Committee of Officials (SCO), ARENA, the Clean Energy Regulator (CER) and the Clean Energy Finance Corporation (CEFC) has been established by the AEMC to provide high-level input on related reliability matters. The initial reference group meeting was held in early August, and comments made at that meeting were incorporated into this paper.

In addition, the AEMC is also establishing a technical working group to provide technical advice, and to assist with the development of recommendations for this Review. The AEMC intends for the group to comprise representatives from the market bodies (AEMO and the AER), ARENA, consumer groups, large energy users, conventional generators, renewable generators, retailers, demand response providers, and transmission and distribution network service providers.

### 1.5.2 Submissions to the issues paper

This paper represents the first stage of public consultation. The Commission invites comments from interested parties in response to this issues paper by **19 September 2017**. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

We would also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Sarah-Jane Derby at 02 8296 7823 or sarah.derby@aemc.gov.au.

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13 See: http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions.

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting project reference code "EPR0060".

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

If choosing to make submissions by mail, the submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:[14]

Australian Energy Market Commission

PO Box A2449

Sydney South NSW 1235

## 1.6 Structure of this issues paper

The remainder of this issues paper is structured as follows:

- chapter 2 discusses the current reliability frameworks including how reliability is driven in the NEM
- chapter 3 discusses the drivers of change that have the potential to affect reliability in the long term
- chapter 4 sets out the assessment framework for this Review
- chapter 5 discusses ways to incorporate variable renewable generation into the NEM
- chapter 6 discusses the market-based aspects of the reliability framework
- chapter 7 discusses the intervention aspects of the reliability framework
- appendix A discusses the historical performance of reliability in the NEM
- appendix B discusses the different types of demand response in the NEM.

14 The envelope must be clearly marked with the relevant project reference code, as above. Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter. If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

# 2 Current reliability frameworks

This chapter provides an **overview** of the current reliability frameworks, specifically:

- section 2.1 discusses the operational requirements for a reliable electricity system
- section 2.2 discusses the reliability framework.

## 2.1 Operational requirements for a reliable electricity system

To achieve a reliable electricity system, the potential supply of electricity must be at least sufficient to meet demand, even as both fluctuate over time. From an operational perspective, it is not sufficient to just have supply meet demand, there also needs to be an adequate level of reserve over demand levels at a particular point in time in order to make sure that it is a secure system. This requires two conditions to be met:

- There must be adequate *dispatchable capacity* for supply to both meet demand, and provide some reserves. This can include both generation and demand response.
- There must be systems to make sure capacity is *actually dispatched* when needed.

Both supply and demand have dispatchable and non-dispatchable components.

**Dispatchable** sources are important from a reliability point of view. Dispatchable capacity refers to sources of electricity that can be dispatched at the request of the market operator, AEMO, and have their output forecast with a high degree of certainty. For example, the generating units can be turned on or off, or adjust their output according to an instruction. Such sources include traditional generation sources (coal, gas, hydro), storage facilities (batteries, pumped hydro), as well as dispatchable load, such as large smelters.

In contrast, variable intermittent generation sources, such as wind and solar, are **non-dispatchable.** In other words, the availability of these technologies is largely not at the discretion of the party who controls them. Instead, generation is driven by the time of year, weather conditions and time of day. However, intermittent generation often has a much lower marginal operational cost than dispatchable generation. For example, wind and solar PV have zero fuel costs. In a system which seeks to minimise costs, they will tend to be deployed first with the remaining demand taken up by dispatchable resources.

These concepts are important in electricity markets since the supply and demand for electricity must be instantaneously balanced in order to make sure that there is a safe, secure, reliable supply of electricity for consumers.

It should be noted that the examples above focus on capacity which is actually deployed. Theoretically the cheapest possible system that is physically capable of meeting demand would invest only in this capacity. Of course, this is unrealistic. The amount of capacity available is relatively fixed compared to demand, as new generation cannot be built on a second to second basis. Furthermore, the supply and demand for electricity cannot be forecast with perfect accuracy. The system needs to be prepared for circumstances where there is an unusual spike in demand or withdrawal of capacity - for example, if there is an unusually hot day or a large generator experiences an outage. To achieve reliability under these conditions, somewhat more capacity must be available than is usually actually deployed (that is, reserves).

A greater level of reserve capacity means a lower risk of unmet consumer demand - but higher costs borne by consumers. The framework for reliability seeks to manage this trade-off in a way which reflects how much consumers value reliability as discussed in chapter 4.

## 2.2 The reliability framework

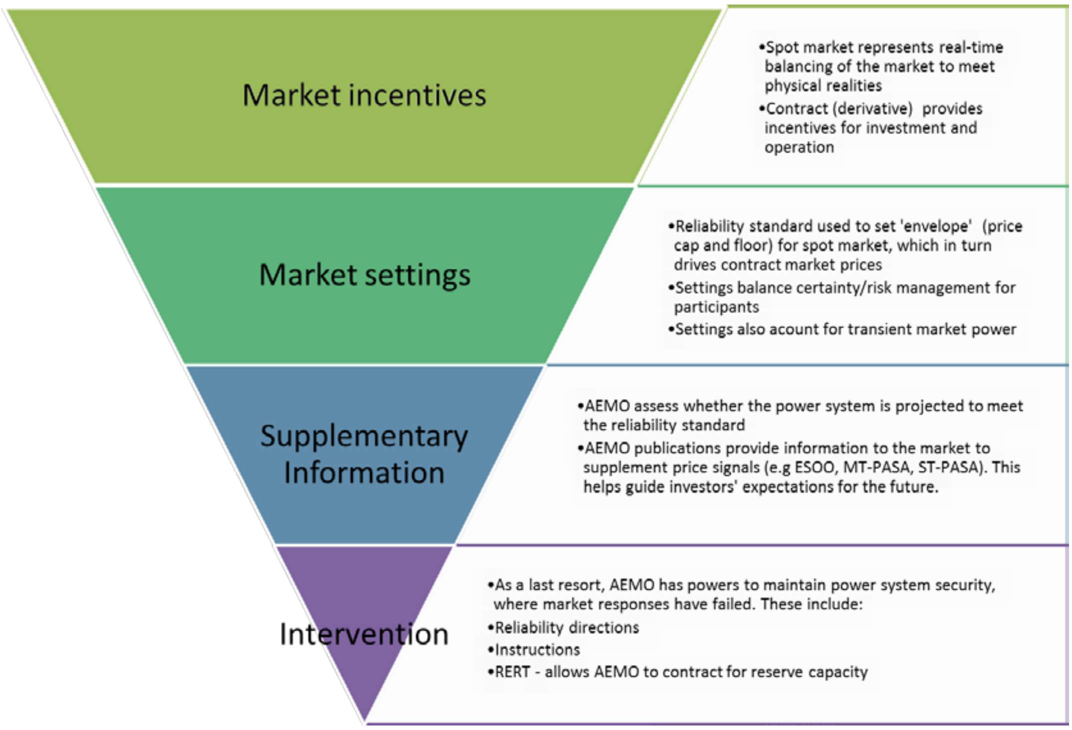
The regulatory framework for reliability in the NEM can be described as market based, but with an escalating series of interventions to account for market limitations. Broadly, market-based solutions are preferred to centrally planned or mandated ones. Markets provide incentives to be innovative, which benefits consumers. This is because competitive pressures are thought to drive more cost-effective and efficient investment, operational and consumption decisions. The iterative process of many participants transacting also allows for greater responsiveness to changing information and circumstances. For a more detailed discussion about how market signals will generally lead to better outcomes than regulation see chapter 4.

For markets to succeed in providing reliability, there needs to be a framework in place to provide the following:

- incentives for efficient investment in, and operation of, both dispatchable and non-dispatchable energy resources
- information to guide investment and operation
- sufficient certainty for investment.

Figure 2.1 provides an overview of the existing reliability framework, including the reliability standards, the price settings that underpin the market settings which themselves underpin reliability in the NEM, and AEMO’s intervention mechanisms. Each of these elements is discussed in detail below.

### Figure 2.1 Markets plus an escalating series of interventions




It is important to note that the NEM in the past decade has experienced high levels of reliability under the above framework. Over this period there have only been two occasions where unserved energy was experienced.[15] These two periods both occurred in years with a greater number of reserve shortages. Appendix A explores the historical performance of reliability in the NEM.

### 2.2.1 Market incentives

The buying and selling of electricity, as well as associated financial products, via contract and spot markets is the main mechanism through which reliability is delivered. Based on these market signals, market participants make investment, retirement and operational decisions. These markets create a financial incentive for adequate generation and demand-side resources to be built and dispatched. Prices in these markets provide information about the balance of supply and demand for electricity at different places and times. In particular, contract markets support investment in capacity, as well as providing incentives to be available when needed in an operational timeframe. In turn, this supports reliability, by providing certainty to investors that the value of their investments can be recouped.

**Spot markets**

Like any market, the NEM was established with a certain pricing framework, in this case, a gross pool design with mandatory participation. Generators sell all of their

15 Unserved energy is discussed later in this chapter. There have been other instances where consumer demand for electricity may not have been met. This could be the result of security related outages, or outages on the network that do not count toward measures of unserved energy.

electricity through the market, which matches supply and demand instantaneously. From the generators' offers the market dispatch engine determines the combination of generation to meet demand in the most cost-efficient way, given the physical limitations of the power system. AEMO then issues dispatch instructions to these generators. The spot market is a way of coordinating the physical dispatch, using AEMO's NEM dispatch engine system, which based on the dispatch offers of generators and the physical limits of the transmission system, makes sure supply is equal to demand in real-time.

Under competitive market conditions, generator offers will usually be based on their short run marginal costs (SRMC) such as fuel and the cost of operating plants. Load offers will usually be based on their value of customer reliability, that is their willingness to pay for the reliable supply of electricity.

Once these offers are received, AEMO then forecasts the customer demand for electricity in each region for each 5-minute interval and, starting from the generator with the lowest bid, dispatches as much generation as necessary to meet the demand. Each generator then receives revenue at the clearing price (known as the "regional reference price") for the electricity delivered – even when that clearing price is above the amount it offers into the market. The NEM’s dispatch process means that all generators earn at least their offer for each unit of electricity delivered. This stream of income is used to cover their fuel cost and variable operating cost expenses. Revenue earned in the spot market, in conjunction with participants' contract positions, supports reliability in the short-term since it provides a financial incentive for generators to supply electricity when there is demand to meet it.

Similarly, to the extent that spot prices are high, retailers or direct-connected customers will receive price signals to potentially engage in demand response, and so reduce their demand. This also assists with reliability.

The reliability settings,[16] developed to meet the reliability standard, form the key price envelope within which the wholesale spot market seeks to balance supply and demand. These are discussed in section 2.2.2 below.

Where a generator receives a clearing price higher than their SRMC, they also earn a margin on the energy they deliver. The gross margin that a generator makes is used to fund its fixed costs and capital costs. New generators enter the market when they expect the gross margin they can earn is sufficient to fund their fixed and capital costs. The entry of new generators in turn, erodes the gross margin that a generator can make in the market by reducing the number of periods in the year where gross margin is earned. However, future spot prices are not observed in the market, and so the contract market (discussed below) is a key part in providing incentives for new generators to enter the market to make up any shortfall between supply and demand in the long-term.

16 Market price cap, market price floor, cumulative price threshold and administered price cap.

### Contract markets

All energy traded through the NEM must be settled through the spot market. The variability of demand and supply conditions results in a spot price that can and does fluctuate significantly on a 30 minute basis. To manage their exposure to the spot market, participants typically seek to enter contracts which convert uncertain future spot prices into more certain wholesale prices. The contract market has been an integral part of the NEM market design since its inception and makes a major contribution to reliability.

As an alternative to entering into hedge contracts, participants can manage risks by entering into 'natural' or physical hedges via vertical integration. For example, a retailer may also hold generating assets, protecting it from fluctuations in the spot price. Such a 'gentailer' with obligations to supply electricity to customers will have a strong incentive to deliver a reliable supply via its own physical plant. Vertical integration between generators and retailers therefore replicates contract market arrangements, just internally within a business. The below discussion can be considered to be equally as relevant to vertically integrated entities as it is to generators entering into hedge contracts with retailers.

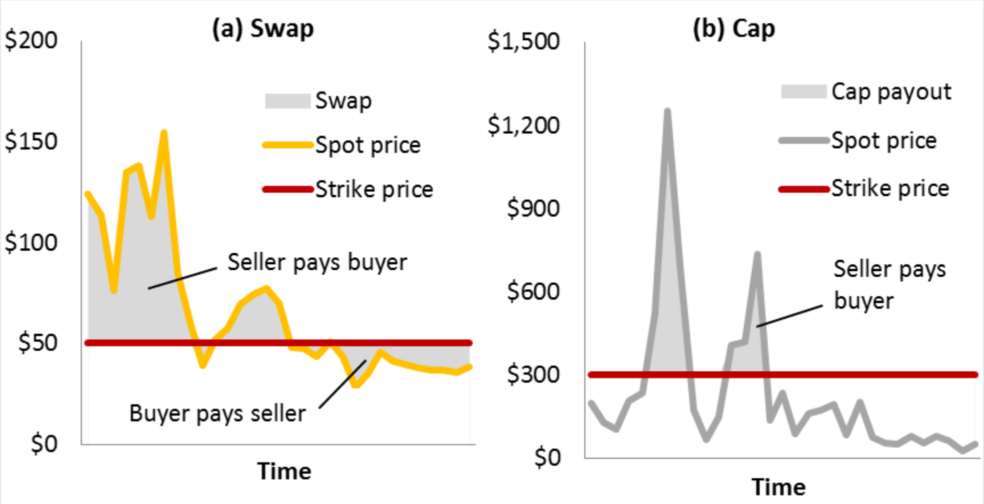
**Box 2.1 Swap and cap contracts**

Contracts in the NEM are currently traded on the ASX (“exchange-traded”) or traded bilaterally (“over the counter” or “OTC”). Two core contract types are “swaps” and “caps”.

- A **swap** contract trades a given volume of energy during a fixed period for a fixed price (the strike price). The variable spot price is, in effect, swapped for the fixed strike price. The contract is settled through payment between the counterparties based on the difference between the spot price and the strike price.

- A **cap** contract trades a fixed volume of energy for a fixed price when the spot price exceeds a specified price. It provides electricity purchasers with insurance against high prices. The standard contract traded in the market is a “$300 cap”. This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period.

**Figure 2.2 Swap and cap contracts**




The price of caps and swaps also reflects a contract premium, or 'cost' of the contract itself, which may in principle be either positive or negative. As expected future spot prices are unobservable, the sign and magnitude of contract premia are also unobservable.

Unlike the spot price, the contract market does not directly drive dispatch. There is a degree of separation between the physical and financial aspects of the market. The Australian contract market is unusual in being a cash settled market. That is, financial contracts traded on the ASX do not involve the physical delivery of electricity.[17]

One outcome of this market design is to promote liquidity by enabling more businesses and individuals to participate. Since participants do not have to physically deliver electricity, some contract market participants are financial intermediaries, for example, Westpac who is a key market maker and liquidity provider in both the exchange traded and over the counter markets.[18] A liquid and functioning market requires many buyers and sellers. Contracts such as caps and swaps become considerably less useful as a risk-management instrument when there is no-one to buy them from or sell them to).

A liquid contract market promotes reliability in two ways. On an operational timescale, contracts provide certainty for participants allowing them to make decisions in the face of risky market conditions. This affects their operational decisions to provide (or not provide) energy, or when to undertake maintenance. For example, a generator that is protected from low prices by a swap is more likely to be operational and fuelled to supply when needed. Consider the following stylised example:

17 See: https://www.asxenergy.com.au/products/overview_of_the_australian_el.

18 See: http://www.aemc.gov.au/getattachment/dd3ccd24-6364-4e88-b531-4d600d77cdb3/Rule-change-request.aspx.

“Ava the generator and Jackson the smelter have entered into a swap for 1 MWh of electricity at time *t* with a strike price of $50 /MWh. Ava takes two hours to turn her plant on. Her cost of fuel and other marginal costs is $30 /MWh.

At *t* - 2 Ava forecasts, based on information from AEMO and her own expectations, that the price at *t* will be between $20 /MWh and $70 / MWh. If Ava chooses not to turn on she will incur neither costs nor revenue. However, she can expect somewhere between a payment of $20 and a loss of $30 as per the terms of the swap. If she keeps her plant running, she will pay $30 in operating costs but earn $50 from selling electricity, for a guaranteed net profit of $20. She chooses to keep running.

If Ava had been uncontracted at *t* - 2, she would have faced an expected profit of between $20 - $30 = -$10 and $70 - $30 = $40 from continuing to run, and of $0 from turning off. Ava is risk averse and doesn't want to run her plant at a loss. Without a contract, she would have chosen not to run.

As it happens, at time *t* the spot price is $50 /MWh. Ava gets a profit of $20 from selling electricity. Jackson is pleased that the reliable supply enables him to continue smelting a consignment of aluminium rings. Everybody is happy.

If there is a general low reserve condition, the spot price is likely to become very high. Under these conditions, Ava will be required to pay out to Jackson the majority of the high spot price and so she needs to be generating at this time to earn the high spot price. This is a very strong incentive for Ava to be available and generating at the time of low reserves just as required. ”

The example above takes place on an hourly timescale. In practice, contracts may also underpin participants' ability to make short- or medium-term decisions with regard to making capacity available which go beyond its offers into the wholesale market. For example, a generator protected through a swap may find it easier to enter a month-to-month contract for fuel.

In the longer term, the contract market supports reliability by facilitating efficient generation investment and retirement decisions. It does this through two mechanisms: by providing information on expected future market prices, and by providing a mechanism through which new generation can be financed.

Contract prices provide information about expected future spot prices, which in turn reflect participants’ views of future wholesale market demand and supply conditions. As expected future spot prices are not directly observable in the NEM participants tend to look to:

- Forward-dated swap contract strike prices – to provide an indication of market expectations of future average spot prices.

- Forward-dated cap contract premia – to provide an indication of market expectations of the future magnitude and duration of spot prices in excess of the cap strike price (typically, $300/MWh).

Taken together, these prices help inform existing and prospective investors about what are likely to be profitable and unprofitable decisions. For example, if spot prices are expected to be elevated for a large proportion of the year, this would translate to swap strike prices being relatively high, which would provide a signal that new capacity is likely to be profitable and efficient.

Similarly, a supermarket chain across the country, seeing electricity contract prices which suggest that spot prices are expected to be high over the next year, might install new equipment so that it can be more easily engage in demand side participation (for example, demand response) in order to better manage its electricity costs.

Furthermore, investors are often unwilling to provide finance to a generator, large load or retailer at all unless the party has used contracts to hedge its anticipated spot market exposure to at least a minimum extent. Hedging provides a means by which generators can reduce their exposures to volatile spot prices and thereby reduce the risk that their plant will face significantly positive or negative profits in any given year. This, in turn, makes investors willing to provide funds to underwrite capacity.

The role of contracts in supporting investment is particularly important when conditions in the market are changing rapidly or otherwise more uncertain than usual. Observed or expected high spot prices cannot translate into new capacity without some degree of confidence that these prices will be sustained long enough for investors to recoup the value of their investment. Contracting can provide this confidence by (for example) enabling investors in new generation capacity to 'lock in' a particular price for their generation.

In this way, the contract market supports reliability by enabling investment in, and operational decisions to provide, capacity to meet future demand.

**Relationship between contract and spot market incentives**

Contract markets provide incentives for efficient investment in future capacity, as well as (in conjunction with the spot market) providing incentives for efficient operational decisions in the short-term by enabling plant and load to operate under conditions of uncertainty.[19] To some extent, these incentives mutually support and reinforce each other, as described in the previous section. Signals for investment in capacity now allow for enough capacity to be built so it can be deployed to meet demand in the future. Generators and load are better able to make decisions about when to operate and not operate when they can control their exposure to risk.

19 This is a simplification. There is clearly overlap between these roles. For instance, a large electricity user may enter a bilateral contract with a generator for the physical delivery of electricity, to make sure it has access to enough pre-existing generation capacity to meet its commercial obligations over a certain period. Furthermore, spot and contract prices tend to be correlated, with wholesale price spikes leading to higher contract premia.

However, there is inevitably some tension between the signals which arise from contract and spot markets. By definition, contracts reduce exposure to the spot market. This means contracted participants will be less responsive to spot prices. Again, consider the following stylised example:

> "Jackson the smelter has bought a cap for 1 MWh of energy at time *t* from Ava the generator with a strike price of $100 /MWh. He has agreed to supply a shipment of aluminium rings to a major customer for a price of $140. It takes him four hours to turn his smelter on and off.
>
> At *t - 4*, Jackson forecasts, based on information from AEMO and his own expectations, that the price at *t* will be between $110 /MWh and $150 / MWh. If Jackson turns off now he will incur no costs nor earn revenue. However, he can expect a payment between $10 and $50 as per the terms of the cap. If he keeps his smelter running, he will pay $100 for power but earn $140 by selling rings for a guaranteed net profit of $40. He chooses to keep running.
>
> If Jackson had been uncontracted at *t - 4*, he would have faced an expected profit of between $140 - $110 = $30 and $140 - $150 = -$10 from continuing to run, and of $0 from turning off. Jackson is risk averse and very much wants to avoid running his smelter at a loss. Without a contract, he would have chosen to turn off.
>
> As it happens, at time *t* there is an unexpected spike in demand due to hot weather. The spot price reaches $200, but it is now too late for Jackson to switch off his smelter in time without causing major damage to the plant. Demand across the state exceeds generation, causing unplanned outages. Everybody gets upset."

The example above relies on some uncertainty in forecasting, and a delay between generators and loads observing forecast spot prices and being able to respond. Both of these aspects are to some degree intrinsic characteristics of how these markets interact, rather than an error or anomaly. But, the example also shows how contracts drive behaviour. Contracts exist to hedge uncertainty. If AEMO and market participants could forecast prices with perfect accuracy, or if generators and loads could respond instantaneously to changes in the spot price, there would be little incentive to enter into such hedges.

### 2.2.2 Market settings

In a perfectly competitive market, the above price signals would be sufficient by themselves to deliver an efficient level of reliability. Consumers and investors could simply decide how much they value reliability - or, conversely, how much harm they experience from outages - and purchase wholesale electricity and/or forward contracts accordingly. Prices would adjust based on how much consumers demand at a particular time, and how much generation there is available to meet this demand. High demand for electricity (for example, on hot days) would lead to rising prices, while high amounts of generation (for example, on windy, sunny days) the opposite, so that the market price would always reflect these underlying conditions.

However, wholesale electricity markets fall short of perfect competition in a number of respects, some of which are listed here:[20]

- The supply and demand for electricity must be instantaneously balanced. The 'balancing' process of supply overshooting demand and vice-versa, then adjusting via prices, cannot simply be allowed to occur as it does with other goods in order to maintain a safe, secure, reliable supply of electricity for consumers. This means that enough generation capacity must be available to meet demand at all times to avoid outages.

- Electricity is an 'on-demand' product. Consumption is difficult to shift from one period to another, particularly for residential consumers.

- Supply is typically through common delivery channels (transmission and distribution networks) which sometimes experience congestion, meaning that multiple generators cannot all deliver their output at the same time.

To avoid this situation, the NER set limits on the extent to which the wholesale price can rise (and fall) - a 'price envelope'. This also provides greater certainty for investors by limiting market participants' exposure to high and low prices. Currently, the price of wholesale electricity is capped at $14,200/MWh with a 'floor' of -$1,000/MWh.[21]

When the NEM was established it was considered that in the absence of such a price envelope, due to the factors above, there will be increased risks:

- Purchasers of energy (as price takers) could be exposed to potentially unlimited energy cost risk in any dispatch interval, without any means to manage this risk (for example, demand response). Such an extreme level of risk could make it unlikely that purchasers would be willing to participate in the market.

- Generators could be unwilling to provide energy on a "firm" basis, that is, they would not be willing to enter into contracts as by doing so, the generator would take on the (limitless) exposure to movements in spot prices. Were the generator to have a technical difficulty limiting generation, or be constrained off at a time of high prices, it would have unlimited financial exposure. In this, admittedly extreme, example a participant could stand to lose its entire business in a matter of hours. Such a level of risk could threaten the integrity of the market.

In setting the cap(s), there is a trade-off between providing incentives for investment and avoiding inefficient expenditure. Consumers could have less unmet demand (greater reliability), but this would mean paying for it. The higher the cap, the greater

20 See: http://www.neca.com.au/Files/RP_VOLL_issues_paper_report_Dec2003.pdf.

21 There is also a cumulative price threshold (CPT) which puts in place an administered price cap when the rolling total of the most recent seven days of prices for a region exceeds a certain level. Historically, the CPT has rarely been used.

the incentive for investors and generators to provide reserves[22] - as well as the cost of providing that reserve. This is because reserves are typically deployed during periods of high prices and are often deployed at the market price cap.

**Box 2.2 Value of customer reliability**

Understanding how customers value reliability is an important consideration when planning new network infrastructure. A reliable supply of electricity is important to everyone: electricity interruptions can be costly, but it can also be disproportionately expensive to try to avoid them completely. The key is to strike a balance between delivering secure and reliable electricity supplies, and maintaining reasonable costs for electricity customers.

A value of customer reliability (VCR) measure, represented in dollars per kilowatt-hour, indicates the average value different types of customers place on having reliable electricity supplies under different conditions. VCR surveys can therefore help guide electricity planning and decisions on investments by energy businesses, governments and regulatory authorities.

In September 2014 AEMO released its *Value of customer reliability review: final report* which provided national level values of customer reliability for the first time.[23] AEMO surveyed a representative sample of consumers. Typically, VCR surveys focus on asking consumers how much they would be willing to pay (or alternatively, accept in compensation) to avoid various outages with various characteristics, or to choose between different scenarios of outages and compensation (‘choice modelling’).

The study estimated the value that all customers place on the reliability of supply from the grid based on a survey of different customer types across all NEM states and an average of the different values they place on reliability. The report produced estimates for valuations of the cost of outages by customer type and outage length. These values were aggregated to calculate a NEM-wide value of customer reliability of $33,460/MWh.

It is worth noting that the VCR values are *estimates* of the value which consumers attach to reliability. Consumers do not directly purchase reliability, and so 'what consumers want' is not directly observable - although they do express some preferences through indirect means such as the political process. Based on uncertainty from the 'choice modelling' alone, AEMO estimates the 'real' VCR values may be 30 per cent higher or lower than the above figure, which is based on the existing reliability standard.[24] Further, customers' assessment of the value

22 The capacity available to the system operator within a short interval of time to meet demand in case a generator goes down, or there is another disruption to supply.

23 AEMO, ‘Value of Customer Reliability Review: Final Report’, September 2014, p. 1.

24 Uncertainty in other inputs to the VCR means that the range of 'plausible estimates' for VCR may be higher than this. These include inputs such as demand and information provided by network businesses through Regulatory Information Notices. It would be mathematically and otherwise

of reliability will depend upon a number of factors, including whether they have recently experienced outages or not, and how significant these outages were.

**The reliability standard and settings**

The reliability standard is measured in terms of maximum expected unserved energy (USE), or the amount of energy that is required by customers but cannot be supplied.. The standard is discussed in more detail in chapter 6.

Currently, the reliability standard is set at 0.002% of the region's annual energy consumption in a financial year. In other words, the standard requires that there be sufficient generation and transmission interconnection such that 99.998% of annual demand for electricity is expected to be supplied. Having the standard set at this level reflects the fact that the most efficient level of reliability is not 0% unserved energy. Such an approach would be inefficient: the cost of the provision of supply of energy at all times would exceed the value placed on it by consumers, given this value is not a constant and varies over time and with the duration and frequency of interruptions.

The standard is underpinned by the four reliability price settings, namely: the market price cap, the cumulative price threshold, the administered price cap, and the market floor price. These parameters are set through consideration of what they would need to be for the reliability standard to be met. As described in the previous section, the role of these price settings is to alleviate potential inefficiencies arising from imperfect competition in short timeframes in the NEM, and to limit market participants' exposure to high and low prices, while delivering capacity to meet consumer demand at least to the level of the reliability standard.

What exactly the reliability standard *is* is not entirely tangible. It is not a test against which the market is formally assessed after the fact. Neither is it a regulatory or performance standard that is 'enforced'. Rather, it is a criterion which bodies such as the Reliability Panel and AEMO use as an input into their decision making. For example, the Reliability Panel uses the 0.002% figure (along with other inputs) to determine what is an appropriate level for the wholesale price cap. It is also the measure which when translated into reserve margins provides operational guidance for AEMO to engage in medium-term intervention. More broadly, AEMO is responsible under the NER for operationalising the reliability standard across the power system in accordance with standards and guidelines (see below).

While AEMO provides information to the market based on, and operates the system with reference to the 0.002% standard, in the short term AEMO pursues a 0% target. That is, in its day-to day-operation of the power system AEMO seeks to 'clear the market' such that no demand goes unserved. The 0.002% of unmet demand is expected to arise from contingencies such as unplanned outages.

complex for AEMO to convert this uncertainty into an upper and lower bound ('confidence interval') for VCR estimates, and AEMO has not sought to do so.

### 2.2.3 AEMO's operationalisation of the reliability standard and information provisions

In relation to planning and operationalising the reliability standard, AEMO performs the following functions:

- assess whether the power system meets, and is projected to meet, the reliability standard
- identify and quantify any projected failure to meet the reliability standard
- publish forecasts regarding reliability and its components to inform market participants, NSPs and potential investors, over different time intervals, including ten-year, two-year and six-day outlooks and for shorter time periods including one day and one hour ahead through pre-dispatch
- monitor demand and generation capacity, and if necessary, initiate action in relation to a relevant AEMO intervention event to maintain the reliability of supply and power system security where practicable. This may include:
  - publishing information about the potential for, or the occurrence of, a situation that could significantly impact, or is significantly impacting, on power system security
  - declaring a low reserve condition when AEMO considers the balance of generation capacity and demand for the assessment period does not meet the reliability standard
  - declaring a lack of reserve level 1, 2 or 3 to advise whenever capacity reserves reduce below the level required to manage credible contingency events
  - following the processes set out in the NER if AEMO declares a lack of reserve or low reserve condition event, including publishing any unforeseeable circumstances that may require AEMO to implement an intervention event (for instance issuing an instruction or direction, or exercising reliability and emergency reserve trader powers).

While most reliability aspects are left to the market, the day-to-day operationalisation of the reliability standard is primarily AEMO's responsibility as system operator of the NEM. AEMO must continuously monitor levels of generation as generators retire from the market and new generators take their place. The NER does not give specific direction to AEMO on how to implement the reliability standard.

As noted above, AEMO issues publications which provide additional information to the market (that is, over and above the information contained in contract and spot market prices). Market information is provided in a number of formats and time frames ranging from long-term projections (more than 10 years) that are published annually, through to the detailed five- and thirty-minute pre-dispatch price and demand projections. This helps guide market participants' expectations of the future, enabling more efficient investment and operation decisions. Some of these publications include:

- Electricity Statement of Opportunities (ESOO) – projects whether there will be adequate supply of electricity over a ten year-period.
- Projected Assessment of System Adequacy (PASA) – projects whether there will be short-term balance of supply and demand for different forward intervals (for example, over the next two years, six days or over the next day).
- Pre-dispatch schedules – forecasts 30-minute pre-dispatch data by region to the end of the next market day and is updated half hourly and also includes a 5-minute pre-dispatch which forecasts one hour ahead.
- Energy Adequacy Assessment Projection (EAAP) – provides information on the impact of potential energy constraints, particularly those relating to inputs to production (for example, water shortages or constraints on fuel supply).

AEMO may also publish notices when it declares a low reserve condition (LRC) and lack of reserve (LOR) to advise participants when reserves are projected to be or are below critical levels. These notices are intended to induce a market response – for example, generators may come online in response to a LOR in anticipation of high spot prices.

### 2.2.4 Intervention

Despite the fact that the framework is based around market-driven investment, retirement and operational decisions, it also provides AEMO with powers to intervene in the market to address potential shortfalls of supply. These mechanisms were designed not to inhibit a market response.

Specifically:

- AEMO has Reliability and Emergency Reserve Trader (RERT) obligations. These allow AEMO to contract for reserves ahead of a period where reserves are projected to be insufficient to meet the reliability shortfall (known as a projected reserve shortfall). AEMO is able to dispatch these reserves to manage power system reliability and, where practicable, security.
- AEMO also has the power under NER clause 4.8.9 to issue directions as a last resort measure to maintain or re-establish the power system to a secure, satisfactory or reliable operating state.
- AEMO can also instruct registered participants (clause 4.8.9 instructions) to maintain or re-establish the power system to a reliable operating state. These instructions include restoring load, in accordance with the sensitive loads and priority load shedding schedule procedure for the affected region.

As a precursor to considering the use of the above reliability intervention mechanisms, AEMO may conduct informal negotiations with market participants.

Furthermore, AEMO can use network support and control ancillary services to the extent that the projected reserve shortfall is affected by a network limitation that can be addressed by such services.

If there continues to be a shortfall in supply, AEMO may require involuntary load shedding as a last resort to avoid the risk of a wider system blackout or damage to generator or networks. Network businesses shed this load following schedules provided by the relevant state government.

These various intervention mechanisms (RERT, instructions and directions) provide a safety net in the event that there is insufficient generation capacity to maintain adequate reserves above demand. They provide the ability for AEMO to attempt to reduce the level of any electricity load shedding of customers.

# 3 Drivers of change

Australia's energy system is undergoing a revolution - driven by changing consumer choices and rapidly evolving technology. This is influencing how the reliability frameworks operate. This chapter discusses these drivers of change:

- section 3.1 discusses the demand-side
- section 3.2 discusses the supply-side.

## 3.1 Demand-side

Consumers are a key factor in driving the transformation of the energy sector through the decisions they make about their household and business energy needs.

**Box 3.1 Power of choice**

Reforms flowing from the AEMC's *Power of choice review* have laid foundations for an energy system where more engaged and better informed energy shoppers have greater access to new products and services like solar, storage, electric vehicles and smarter consumption management. The *Power of Choice review* was all about opportunities for consumers to make informed choices about how they use energy; and incentives for efficient investment so community demand for energy services can be met in the lowest cost combination of demand and supply options.

Efficient markets are characterised by effective participation of both the supply and demand sides. The *Power of choice review* identified issues that prevented maximum consumer participation in energy markets. In order to participate consumers need:

- **Clear price signals and incentives:** consumers need clear signals about the cost of their energy consumption to manage their demand; and supply chain businesses need appropriate incentives to implement and facilitate demand side participation options.
- **Informed choices:** consumers need a range of information so they can identify and implement efficient demand options.
- **Tools:** technologies and skills are needed to support pricing, information and demand management options, and to enable consumers to effectively respond to market signals.

Since the publication of the final report for the *Power of choice* review the AEMC has implemented a number of reforms stemming from these recommendations including: removing networks' effective metering monopoly to enable a 'market-led' rollout of smart meters and services; introducing cost reflective network pricing; improving customer access to information about their energy consumption; making it easier for consumers to switch retailers; and allowing AEMO better access to better demand side participation information.

Technological developments, market and regulatory developments and innovation by demand-side management providers over the past decade has made it easier for consumers across all sectors (industrial, commercial and residential) to adapt their consumption patterns in order to manage and control their energy use, and, in turn, their expenditure:

- Home energy management systems can provide demand response and deliver load reductions in a way that goes largely unnoticed by the customer.
- Price signals, either in the form of cost reflective pricing or direct incentives, can encourage customers to shift energy use away from peak times, avoiding inefficient investments in energy equipment and more drastic load shedding events.
- Given appropriate incentives, voluntary load reductions by commercial and industrial users could serve as an alternative to involuntary load shedding to address lack of reserve conditions.

Of particular relevance is the uptake of new, distributed technologies in Australia's electricity sector. These developments are allowing greater opportunities for the demand-side to participate in the NEM, including contributing towards reliability, as detailed further below.

### 3.1.1 Distributed energy resources

The last decade has seen a rise in the penetration of distributed energy resources.[25] A significant proportion of this has come in the form of small-scale solar PV.[26] From 2010 to March 2017, the installed capacity of small-scale PV systems has risen significantly, from around 100 MW to 4,600 MW.

Solar PV is only one of the many technologies emerging that have the potential to alter the operation of the power system. Demand response and energy storage are two other notable technologies that are increasingly being marketed to end consumers, offering the prospect of reduced energy bills and reduced reliance on the grid. There are a number of examples and new and innovative business models in operation in the NEM as described in Box 3.2. These new business models perform different functions for different customers, and try to unlock value from distributed energy resources in different ways. Given that the deployment of distributed energy resources, such as batteries, is nascent, many of these new business models are still at trial stage or are in receipt of funding or other support to test their business model.

25 An integrated system of energy equipment that is connected to the distribution network.

26 The Clean Energy Council calculates that nationally small-scale solar PV accounts for 16 per cent of renewable generation. See: Clean Energy Council, Clean Energy Australia Report 2016, May 2016, p. 8.

**Box 3.2 New business models**

One such example of how energy services companies are aiming to optimise consumers' energy use is provided by Reposit Power. Reposit Power is an energy services company that provides software to optimise the performance of a home battery system. The software uses machine learning to combine information about the household's energy consumption patterns with expected solar generation based on weather forecasts, in order to maximise self-consumption and minimise bills. At times of high wholesale prices, the Reposit software will sell surplus energy back to the grid, enabling households to maximise the economic return from owning battery storage.

New business models can also aggregate the functionality of a network of household and business-owned battery storage systems, in order to provide services such as peak demand management and frequency control. An example of such business models is the AGL Virtual Power Plant (VPP) trial, partially funded by ARENA.[27] AGL states that the Adelaide-based trial, which uses cloud-connected software developed by the US company Sunverge, has already successfully linked more than 60 batteries, which together have stored and delivered over 10,000 kWh. Ultimately, the aim is to create a total of 7MWh of storage capacity and 5MW peaking capacity. This trial shows that the aggregation of distributed energy resources may have the potential to provide an alternative to large-scale and medium-scale generation.

In the future, there is expected to be a large demand for distributed energy resource technologies, such as solar PV, energy storage and electric vehicles. This expected uptake is driven by a range of factors, including:

- the falling costs of these technologies[28]
- increasing functionality of these technologies[29]
- more sophisticated information and control technologies, and fast, cheap computing platforms[30]

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27 See https://arena.gov.au/project/virtual-power-plant/.

28 For example, Bloomberg New Energy Finance predicts that battery packs are likely to experience cost declines at a rate of 19 per cent for every doubling of production due to productivity and efficiency improvements. Further, that the costs of inverters have halved from 2016 to 2017 due to the entrance of a number of competitive inverter manufacturers that have traditionally made inverters for solar plants. Source: Bloomberg New Energy Finance, Economic for some: Grid-scale batteries in Australia, 3 April 2017.

29 For example, the Tesla Powerwall 2 has double the storage capacity, at close to half the price, compared to the Tesla Powerwall 1, with these two models being released less than two years apart. See: http://www.cleanenergyreviews.info/blog/tesla-powerwall-2-solar-battery-review.

30 SAPN notes that remote monitoring and control technology is evolving rapidly, and quickly expanding the range of cost effective solutions available. Installation of more intelligent devices such as distribution transformer monitors, SCADA enabled remote-controlled switching devices

- changing consumer attitudes to electricity supply.[31]

Forecasts support these conclusions. For example, AEMO expects that:[32]

- investment in rooftop solar PV systems will continue to grow, with nearly 20,000 MW installed by 2037-37 compared to less than 5,000MW in 2017
- residential and commercial battery storage uptake will exceed 5,500 MW by 2036-37
- while electric vehicle sales are forecast to remain low overall in Australia (by comparison with traditional vehicles) in the short term, the rate of uptake will increase from 2020 onward.

Distributed energy resources provide opportunities to manage the power system in new ways, particularly with advanced metering and digital technologies. An increased uptake of distributed energy resource will provide additional supply-side resources to be used for the purposes of reliability, while also increasing the flexibility of the demand-side, provided there are market arrangements to capture these benefits.

Historically, the development of distribution networks and the regulatory arrangements that underpin them, have been focussed on DNSPs providing sufficient network capacity to meet consumer *demand* while maintaining the safe, reliable and secure electricity supply. However, in light of the increasing uptake of distributed energy resources and the range of services these technologies are capable of providing, distribution system operations and associated regulatory arrangements are likely to require greater optimisation of investment in, and operation of, distributed energy resources, as well as better coordination of these resources with the wholesale market.

The Commission has recently concluded a project on creating a future distribution market model.[33] One of its findings is of relevance to this Review: that the AEMC will consider how distributed energy resources could be more effectively co-ordinated with the wholesale market in order to provide more flexible resources (either demand-side or supply-side) to better manage reliability within the NEM. This is discussed further in chapter 5.

Similarly, AEMO has been looking at these issues from a power system security point of view. It considers that if the uptake of distributed energy resources is not holistically managed, the systems, in aggregate, can have a material and unpredictable impact on the power system and its dynamics due to their cumulative size and changing

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and advanced meters will help them to manage risk and network performance. See: SAPN, Distribution Annual Planning Report, p. 23.

31 The Commission's 2017 *Retail energy competition review* found that energy consumers have more choices to manage their energy use and are looking to take up new technology options. For example: 20 per cent of consumers now have solar panels; 21 per cent are likely to adopt battery storage in the next two years; and 18 per cent are likely to take up a home energy management system in the next two years.

32 AEMO, Electricity forecasting for the National Electricity Market, June 2017.

33 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model.

characteristics.[34] AEMO has therefore been looking at ways to improve its visibility of distributed energy resources in respect of its role in maintaining power system security:

- AEMO's demand side participation guidelines, will require registered participants to submit demand side participation data annually at the national metering identifier (NEMI) level from April 2018

- AEMO is also undertaking a range of work in the context of distributed energy resources and power system security, including its *Visibility of distributed energy resources* project.

### 3.1.2 Demand response

A particularly key form of demand-side flexibility that could have significant impacts for reliability is demand response. Demand response involves customers changing their usage of electricity in response to signals or requests to do so (see Box 3.3). Demand response is a form of demand-side participation, which are actions that a consumer can take to alter or shift its electricity consumption in response to changing market conditions. The exact mechanisms as to how this can occur are discussed in chapter 5. Essentially, the supply side of the market provides electricity at a price, and the demand side (that is, consumers) directly or indirectly through a service provider respond to the price or the value of the product or service presented to them based on that price.

**Box 3.3 Demand response**

It is generally accepted that there are four different types of demand response, based on the underlying rationale for why it is being used:

- **Ancillary services demand response** – demand response employed for use in ancillary services markets, for example, to respond quickly to brief, unexpected imbalances in supply and demand to return the grid to frequency utilised in the FCAS markets.

- **Network demand response** – demand response employed to manage peak demand within a particular transmission or distribution network.

- **Wholesale demand response** – market driven demand response used to avoid buying electricity driven by either at times when wholesale spot prices are high, or by participant contract positions.

- **Reliability demand response** – demand response employed as an emergency lever during supply emergencies, centrally dispatched or

34 See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO-FPSS-program----Visibility-of-DER.pdf.

controlled to avoid involuntary load shedding and rolling blackouts.

The Commission considers that there are no regulatory barriers to the use of ancillary services demand response in the NEM, under the current framework. In addition, the Commission is considering through the *Frequency control frameworks review* what market and regulatory arrangements are necessary to support effective control of system frequency in the NEM, such as fast frequency response, including how demand response could provide such services. The review is also considering the potential of distributed energy resources to provide frequency control services and any other specific challenges and opportunities associated with, their participation in system security frameworks.

In addition, the Commission considers that there are no barriers to network demand response being used. Further, the Commission is also currently undertaking work in several areas that will further facilitate the potential use of network demand response in the future, as distributed energy resources become more prevalent.

Therefore, for this Review, the focus of demand response is on **wholesale demand response** and **reliability demand response.** Further background to demand response can be found in appendix B.

A 2016 survey for the AEMC suggested that there is at least 235 MW of demand response under contract to retailers, mostly involving exposure to the wholesale market spot price and 310 MW contracted to specialist demand side-management companies.[35]More recently, preliminary information from ARENA's reliability demand response trial suggests that about 700MW of potential demand response capacity could be made available by 1 December 2017 and almost 2000MW of capacity by the end of 2018. ARENA noted that demand response capacity is evenly spread among industrial, commercial and residential users, with a diversity of technologies, including industrial load curtailment and batteries.[36]

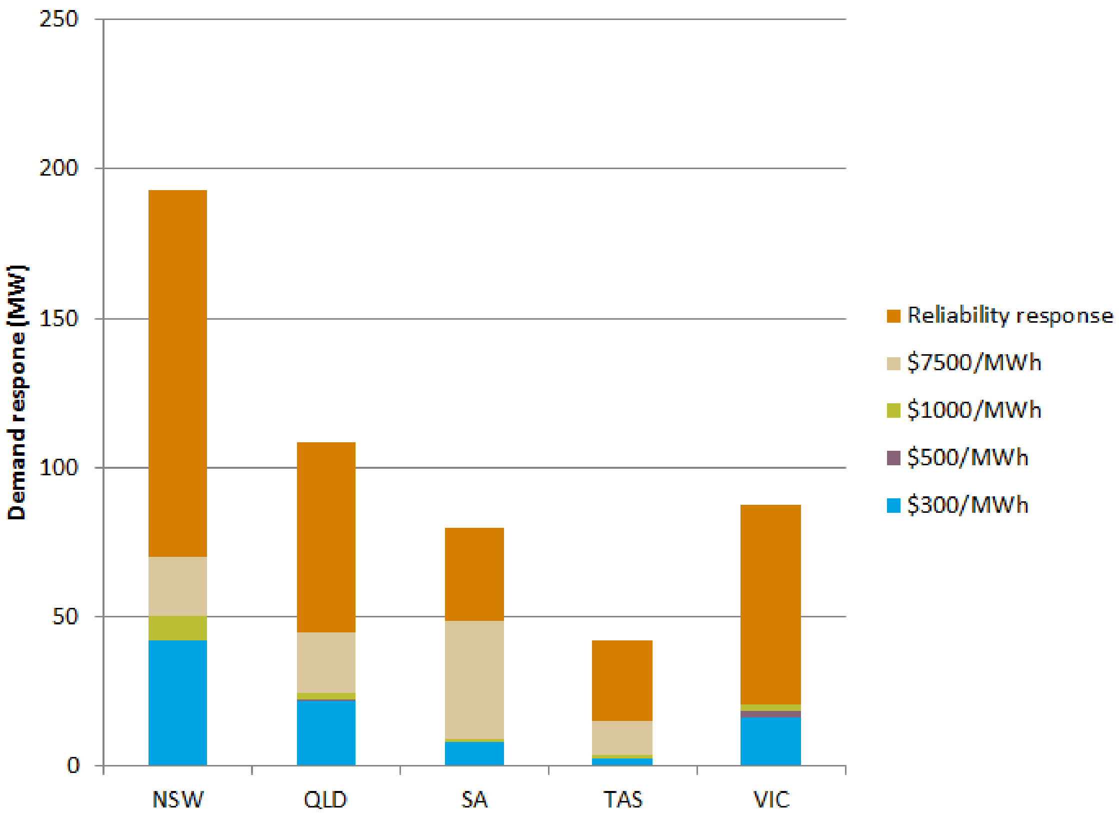
Similarly, Figure 3.1 shows the level of demand side response that AEMO considers to be currently available in the NEM. It considers the amount of demand response that would be expected at certain wholesale prices. For example, AEMO expects there to be approximately 50MW of demand response in NSW when the price reaches $1000/MWh. Further, in the summer of 2017/18, AEMO considers that there is 512MW of demand response across the NEM, which does not include anything that could be

35 See Oakley Greenwood, Current status of DR in the NEM – Interviews with electricity retailers and DR specialist service providers, http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism.

36 This was highlighted in an email to ARENA's stakeholders and has also been reported in the media. See http://www.abc.net.au/news/2017-07-13/household-electricity-trading-app-may-be-funded-by-government/8707010.

procured through the RERT. AEMO also notes that it expects the amount of demand response in the NEM to continue to increase.[37]

**Figure 3.1 Amount of demand response in the NEM, per region**




Note: For the purposes of this data, AEMO defines a reliability response as the expected demand response following the issuing of an LOR2 or LOR3 notice.

Source: AEMO, *Electricity Forecasting Insights*, June 2017.

AEMO and ARENA are also trialling a demand response version of the RERT. This is discussed further in section 7.3.3.

## 3.2 Supply-side

Just like the demand-side, there have been a number of recent trends on the supply-side, specifically:

- the retirement of thermal generation
- the increasing penetration of intermittent, renewable generation
- the coupling of gas and supply prices
- the implications of the above on the operation of the NEM.

37 AEMO, *Energy supply outlook*, June 2017.

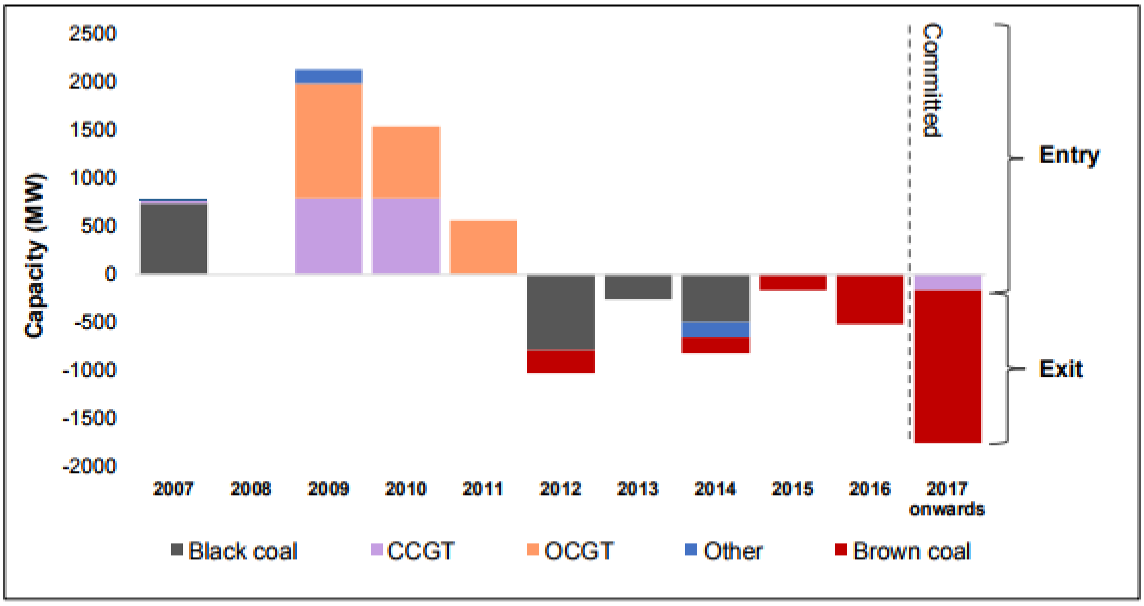
These trends are discussed in more detail below.

### 3.2.1 Continued retirement of thermal generation

Prior to 2009, there was considerable focus from policy makers and participants on the importance of building *new* generation capacity to meet rising demand. But, when demand forecasts failed to meet expectations, it became clear that there was excess capacity in the system. This excess capacity put downward pressure on spot prices, and associated derivatives in the contract market, reducing the profitability of existing generators.

Therefore, instead of seeing additional thermal, synchronous capacity constructed, the NEM saw the *retirement* of existing generators in response to declining demand. Figure 3.2 shows the entry and exit of thermal generation capacity across the NEM by fuel/technology. This shows that no new thermal generation has entered the market since 2011. Indeed, there has been a strong trend of coal-fired generation *exiting* the market.

**Figure 3.2 Changes in thermal generation capacity by fuel type**




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

Retirement decisions by existing generators are now increasingly important to outcomes for the physical system, and the market. Most notably, there have been two recent significant exits from the generation market:

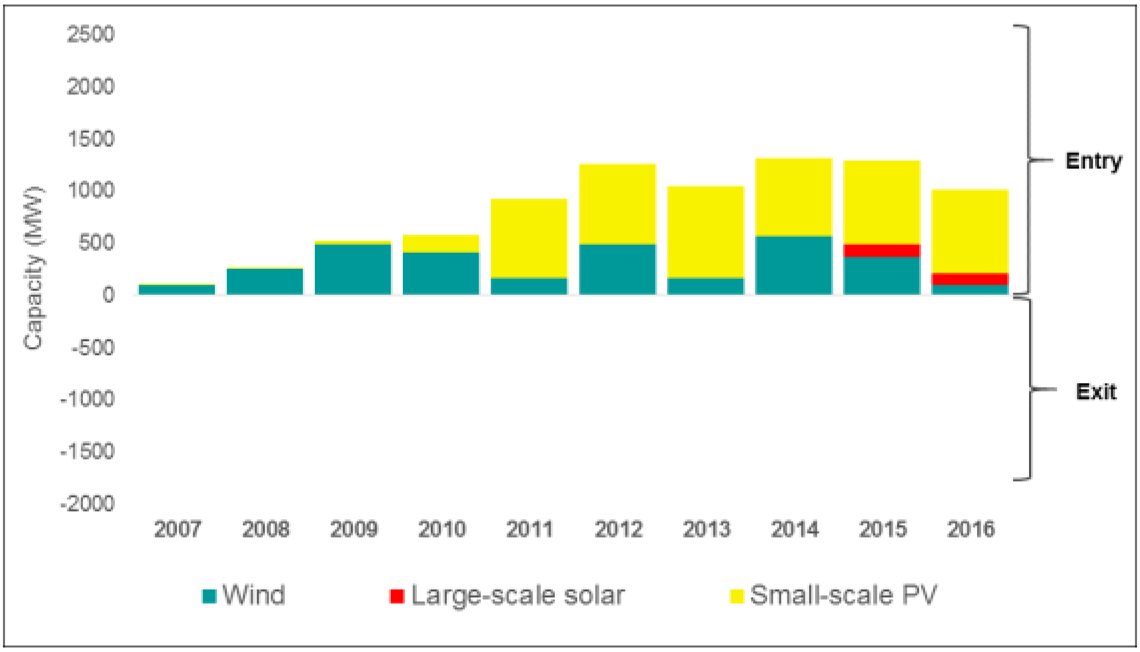
- Northern Power Station in South Australia was withdrawn from the market in May 2016 (520 MW).
- Hazelwood Power Station in the Latrobe Valley, Victoria was closed in March 2017 (1,600 MW).

Both of these closures have, and are likely to have, a significant effect on price outcomes, and potentially the reliability of the system. More closures are expected to occur, for example, AGL has committed to not extending the operating life of Liddell (2000 MW) beyond 2022.

### 3.2.2 Increasing penetration of renewable, intermittent generation

While there has been no new thermal generation constructed in the NEM since 2011, there has been considerable investment in wind farms and small-scale solar over this period, largely driven by the Large Renewable Energy Target (see Box 3.4). Figure 3.3 shows the entry and exit of intermittent plant by technology type. Around 5,000 MW of small-scale PV and 3,700 MW of wind have been constructed since 2007 across the NEM.

**Figure 3.3 Entry and exit of intermittent plant by technology type**




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

The Clean Energy Council recently reported that the proportion of Australia's energy generated by renewables rose significantly from 2015 to 2016 - from 14.6 per cent to 17.3 per cent - representing the "highest proportion of Australia's electricity of any year this century".[38] Wind and solar technologies accounted for approximately 49 per cent of renewable generation nationally in 2016.[39] Renewable projects set to start construction in 2017 are valued at $6.9 billion and represent 3,150 MW of new generation capacity.[40]

38 Clean Energy Council, Clean Energy Australia Report 2016, Melbourne, May 2016, p. 8.

39 Ibid, p. 8.

40 Ibid, p. 6.

**Box 3.4 Large Renewable Energy Target**

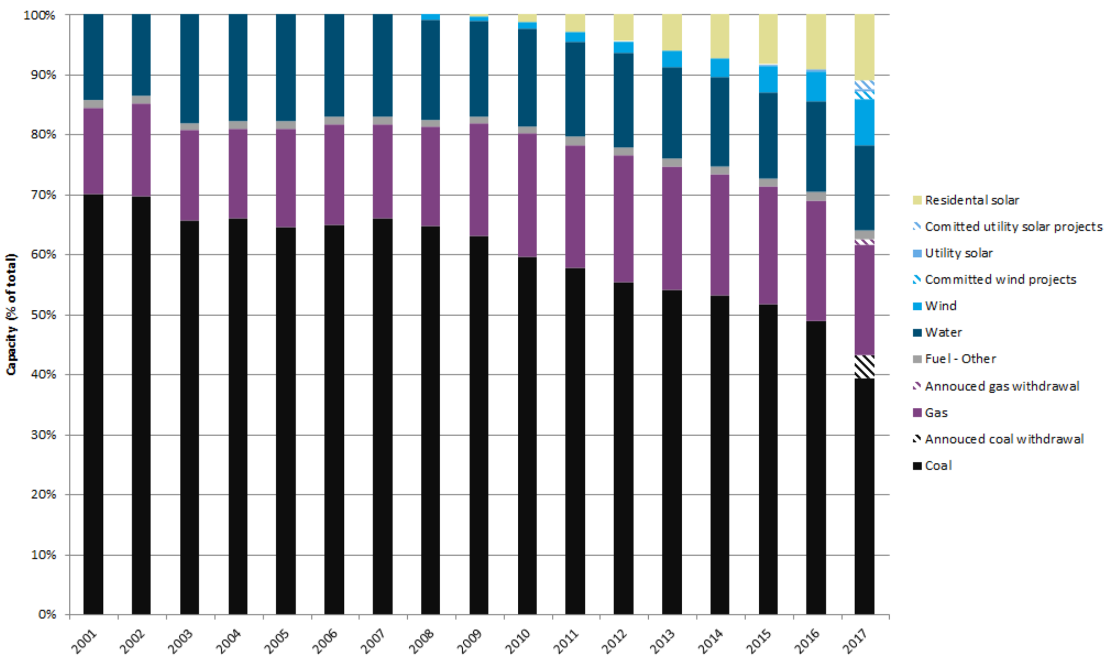
The national Renewable Energy Target (RET) scheme, includes both the Large Renewable Energy Target (LRET) and the small-scale renewable energy scheme (SRES), which aims to encourage the additional generation of electricity from renewable sources, reduce emissions of greenhouse gases in the electricity sector, and make sure that renewable energy sources are ecologically sustainable.[41]

The LRET policy design requires electricity retailers to source a proportion of their electricity from renewable sources. The target is for a fixed 33,000 GWh of energy from eligible large-scale generators in each year from 2020 to 2030. The target is fixed, and therefore the proportion of total generation it represents varies with demand.

### 3.2.3 Overall changes in NEM generation

The combination of thermal generating exiting, and the increased entry of intermittent, renewable generation, has had implications for the overall generation mix in the NEM.

**Figure 3.4 Changes in NEM generation capacity by percentage of total**




Sources: AEMO, *Electricity statement of opportunity reports* from 2001 - 2016. AEMO, *Generation information page*, accessed 25 July 2017. Clean Energy Regulator, *Postcode data for small-scale installations*, accessed 25 July 2017.

In both absolute and relative terms, there has been a decrease in dispatchable generation since 2001. In 2001, approximately 100 per cent of registered generation in

41 Renewable Energy (Electricity) Act 2000 (Cth), s3.

the NEM was dispatchable; however, this is now closer to 80 per cent. Other notable observations include:

- The capacity of coal fired power peaked in 2009 and has declined since. Additionally, the capacity of coal fired power in the NEM is expected to continue to reduce with the announced withdrawal of Liddell power station (2000MW)[42] and no new coal fired power committed to being built.
- The capacity of gas fired generation has significantly increased since 2001, almost doubling in total capacity.
- Intermittent generation in the NEM, including residential solar, has substantially increased since 2001. The capacity of intermittent generation is expected to continue to increase with committed wind and utility solar projects.

### 3.2.4 Characteristics of different forms of electricity generation

The increasing contribution of intermittent technologies to electricity supply is focussing attention on the characteristics of different generation technologies.

Thermal generation and hydro-electric plant are **synchronous**, which provides system security benefits such as provision of inertia and system strength.[43] However, these forms of generation are also ***dispatchable***, which is important from a reliability point of view.

The extent to which these generators can be dispatched does depend on its fuel source as well:

- In the short-term, thermal generation availability is driven by its contract position at a particular point in time, but can be considered to be largely at the discretion of the generating business, as long as fuel is secured and the generating unit is not down for maintenance. In the long-term, these units' availability is determined by fuel supply, the ability to enter into long-term contracts, and the cumulative wear and tear on the units, which influences their outage rates and availability more generally.
- Similarly, in the short-term, hydroelectric plant availability is driven by its contract position at a particular point in time, but can be considered to be largely at the discretion of generating business, provided there is energy in storage and the unit is not down for maintenance.[44] In the long-term, the availability of these units is again driven by their contract positions, as well as inflow patterns and decisions to build-up or run-down storages.

42 AGL has announced the intention to withdraw Liddell Power Station in March 2022.

43 See: http://www.aemc.gov.au/getattachment/f510069a-791b-4e4d-8bc0-9e6a216be7a2/Final-report.aspx.

44 Run-of-river hydro plants are an exception as they exhibit similar characteristics to wind and solar.

**Box 3.5 Coupling of gas and electricity prices**

Over the last five years, there has been considerable structural change in the east-coast gas market, driven by the establishment of a liquefied natural gas (LNG) export industry.

During the 1990s and 2000s, the eastern Australian wholesale gas market was characterised by the use of long-term bilateral contracts between a relatively small number of producers and consumers. The price of gas as a fuel for power generation was relatively low, given that gas-fired generators had to compete with low-cost coal fired power stations.

The discovery of large reserves of coal-seam gas in Queensland created the scale, and so the opportunity, to establish a liquefied natural gas export industry. In 2010, Australian and international energy businesses started to develop export capabilities, with a view to selling into the (then) higher priced Asian market. As of late 2016, all of these projects have been completed and are producing gas for export.

The consequences of the establishment of the liquefied natural gas export facilities are considerable with gas now being more expensive in the domestic market.

Linking of the domestic market to the international liquefied natural gas market has lifted the once low domestic gas price (around $4 per GJ) to the opportunity cost of exporting gas into the international market (in the order of $8-9 per GJ). Moreover, the massive increase in demand for gas together with a constrained supply side through government moratoriums on gas exploration and developments, has placed pressure on domestic supply infrastructure leading to yet further pressure on prices at times of high domestic gas demand (that is, winter).

In addition, the expiry of long-term bilateral contracts and difficulty in renewing on commercially acceptable terms has meant that secondary markets are increasingly relevant. Put another way, prices in the spot market are becoming more and more representative of the marginal cost of gas.

Higher gas prices led to higher electricity prices, with sustained high prices for extended periods in June and July 2016. The high gas price was in part a function of the demand for gas as a fuel for power generation. The closure of Hazelwood power station – and the attendant increase in gas-fired power generation – is likely to strengthen the connection between gas and electricity prices.

In contrast, intermittent generation, such as wind and solar, are **non-synchronous**, which has implications for system security, as well as being ***non-dispatchable.*** The future growth in installations of storage units linked to solar and wind projects have the potential to lessen this availability distinction between solar and wind, and other forms of generation. We are already starting to see some evidence of this: the battery built under the South Australian Government tender will be connected to the Hornsdale wind farm, which is currently under construction.[45]

Wind and solar plants have other availability characteristics that distinguish them from alternative types of generation. In particular, they are unaffected by the availability or the price of gas and other fuels. Similarly, wind and solar technologies are not exposed to drought as hydro-electric plants can be. Hydro-electric plants can also stockpile resources in anticipation of high price events in the future.

Further, the output of wind farms (or solar plants) that are located close to other wind farms (or solar plants) are highly correlated. When wind farms located close to one another are generating, they tend to generate at the same time, and vice versa. Finally, wind and solar plants can also display a relatively high degree of predictability of availability in the short-term.

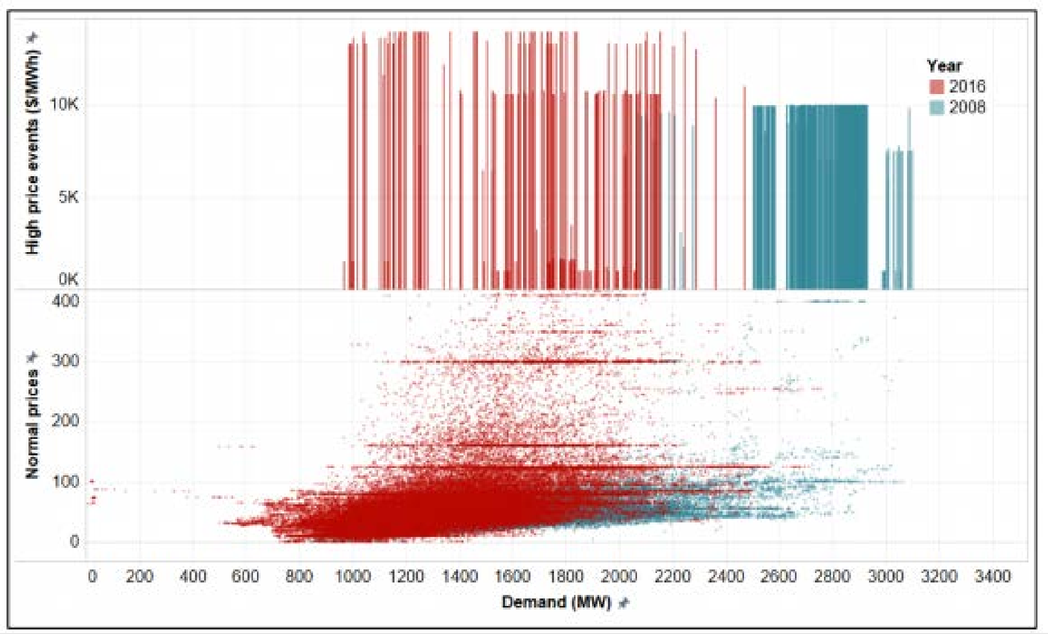
A potential impact of the increasing penetration of solar and wind technologies on the NEM is that large volumes and/or proportions of generation in certain regions may become available (or unavailable) at the same time, and that this is outside the control of the generation business, so unresponsive to price signals in the NEM and so may impact on the reliability of supply.

**Box 3.6 Potential changes in the relationship between high price events and demand**

The Reliability Panel's issues paper for the *Reliability standard and settings review*, demonstrated some evidence of a breakdown in the historical close relationship between high price events and periods of high demand in South Australia. Demand can be considered to be a proxy for reserves. Where there is high demand, there are likely to be low reserves and vice versa. Figure 3.5 demonstrates this. In 2008 there is a clear relationship between demand and price: as demand increases, so does price, with market price cap events associated with levels of demand above 2,500 MW. But, in 2016, the relationship between price and demand is weaker; higher prices regularly occurred at levels of demand as low as 1,000 MW.

45 See: https://www.premier.sa.gov.au/index.php/jay-weatherill-news-releases/7736-tesla-to-pair-world-s-largest-lithium-ion-battery-with-neoen-wind-farm-in-sa.

**Figure 3.5 Connection between price and demand, South Australia 2008 and 2016**




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

Various factors may have contributed to the occurrence of high prices with lower demand in South Australia in 2016. Outages on the Heywood interconnector may have played a role as well as increasing wholesale gas prices and changes in the overall generation mix (the combined outcome of thermal plant withdrawal and increased intermittent generation).

The discussion in Box 3.6 suggests that within certain regions, and at certain times, there may be a disconnect between prices and level of reserves. It may be that high demand is not necessarily a pre-condition for high prices in some regions. Although the growth of intermittent generation in these instances may only be one factor, the patterns of availability of wind and solar farms are likely to be significant to price outcomes in those regions.

### 3.2.5 Government funding for additional dispatchable generation capacity

The South Australian, Victorian, Queensland and Commonwealth governments this year have announced that they will fund, subsidise or study the feasibility of investing in additional dispatchable generation capacity:

- the South Australian Government's "our energy plan", which amongst other things, includes building a state-owned gas power generator, funding a large battery project, incentives for gas development, and new ministerial powers[46] to

46 These new ministerial powers include providing the Energy Minister with the power to give any directions to AEMO, generators and retailers that he or she thinks are reasonably necessary to respond to an electricity supply emergency, and where the maximum period of emergency that

direct AEMO, generators and retailers, where necessary, to respond to an electricity supply emergency[47]

- the Victorian Government's announcement calling for expressions of interest to build Australia's first grid scale battery storage facility[48]
- a feasibility study by ARENA into the Prime Minister's announcement to boost the output of the Snowy Mountains Hydroelectric scheme by 2,000 MW[49]
- the development of an implementation plan with market bodies and industry participants to deliver on gas companies "guarantee that gas is available to meet demand", fast tracking any possible market reforms, and transparency measures[50]
- the Commonwealth and Tasmanian governments announcing they would undertake a feasibility study to expand the Tasmanian hydro system through schemes that could deliver up to 2,500 MW of pumped storage capacity, and through possible expansions of the Tarraleah and Gordon power stations[51]
- the Queensland government announcing that Stanwell Corporation 385 MW Swanbank E gas-fired power station will be restarted to reduce the price volatility in the electricity market.[52]

These announcements have suggested an increasing focus from governments on having a reliable supply of electricity. If all these investments are proceeded with, there will be implications for reliability outcomes in the NEM.

### 3.2.6 Integration of emissions and energy policy

Since July 2015, Australia has committed, under the Paris Agreement, to reduce carbon emissions by 26-28 per cent below 2005 levels by 2030. Despite the new emissions reduction target described above, the policy settings around emissions reduction have not changed since July 2015.

There has been recognition by a wide range of stakeholders that further action will be needed in order to reduce emissions from the electricity sector to meet Australia's

may be declared is longer than that which can be declared by the Governor under the Essential Services Act (14 days rather than seven days).

47 Jay Weatherill (Premier), South Australia is taking charge of its energy future, media release, Parliament House, Adelaide, 14 March 2017.

48 See: http://www.premier.vic.gov.au/australias-largest-battery-to-be-built-in-victoria/.

49 See: https://www.pm.gov.au/media/2017-03-16/securing-australias-energy-future-snowy-mountains-20.

50 See: https://www.pm.gov.au/media/2017-03-15/measures-agreed-cheaper-more-reliable-gas.

51 See: https://www.pm.gov.au/media/2017-04-20/new-tasmanian-pumped-hydro.

52 See: http://statements.qld.gov.au/Statement/2017/6/4/swanbank-e-power-station-fires-up-again.

agreed international commitments. Lack of sustainable policy in this area is creating uncertainty, which in turn is having a negative effect on investor confidence.

Recently, the AEMC has been asked by the governments of South Australia, Queensland, Victoria and the Australian Capital Territory to develop design options for a Clean Energy Target, as recommended in the *Independent Review into the Future Security of the National Electricity Market*.[53] A final report on this advice is due in October 2017.

53 See: http://www.aemc.gov.au/News-Center/What-s-New/Announcements/Modelling-of-a-Clean-Energy-Target-mechanism.

# 4 Assessment framework

This chapter sets out the assessment framework for how the AEMC will conduct this Review, specifically:

- section 4.1 discusses the National Electricity Objective
- section 4.2 discusses the trade-offs inherent in the frameworks for reliability
- section 4.3 discusses the principles we will consider
- section 4.4 discusses our assessment approach.

## 4.1 The National Electricity Objective

The overarching objective guiding the Commission's approach to this Review is the National Electricity Objective (NEO). The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the NEO. Similarly, with any related rule changes, the Commission must consider whether the proposed rules promote the NEO. The NEO is set out in section 7 of the National Electricity Law (NEL), which states:

> “The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.”

Based on a preliminary assessment of the issues raised by the Review, the Commission considers that the relevant aspects of the NEO for further consideration are the efficient investment in, and operation of electricity with respect to the **price** and **reliability** of supply of electricity, as well as the **reliability** of the national electricity system.

## 4.2 Trade-offs inherent in the frameworks for reliability

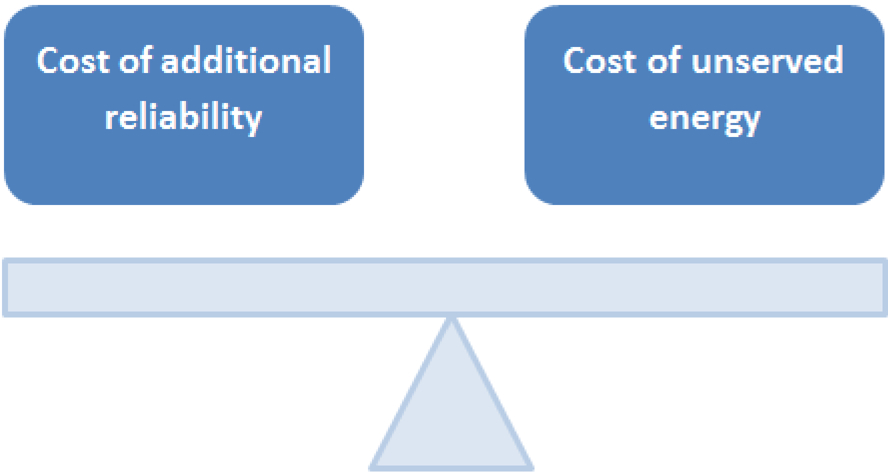
Consistent with the relevant aspects of the NEO identified above, there are two costs that need to be balanced in considering reliability frameworks:

- Cost of additional reliability - higher levels of reliability require more investment in energy capacity, or more stringent operating conditions, and so a higher cost per unit of energy supplied to achieve financial viability. These costs will be reflected in consumer prices.
- Cost of unserved energy - the alternative is not to supply the energy, that is, to allow a higher expected level of supply interruptions to consumers. This too has

costs, which are the costs of not having energy when consumers want it (known as the value of customer reliability).

As the below figure illustrates a reliability framework embodies a trade-off, made on behalf of consumers, between the prices paid for electricity and the cost of not having energy when we need it. The need to balance these costs illustrates that the most efficient level of reliability is not having zero per cent unserved energy. Such an approach would be inefficient: the cost of the provision of a guaranteed supply of energy would exceed the value placed on it by consumers.

**Figure 4.1 The trade-off inherent to a reliability framework**




The key question for this Review is therefore how to create reliability frameworks that efficiently balance the costs set out above, given the uncertainties.

Broadly there are two types of mechanisms to that contribute towards this balance:

- market-based mechanisms
- intervention mechanisms.

The existing reliability framework, as discussed in chapter 2 is largely market-based, but does have some elements of intervention intrinsic in its design (for example, the reliability settings) and allows for other interventions in specific circumstances (for example, the RERT).

The Commission considers that, intervention-based approaches, however well designed are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. Markets put consumers at the heart of decision making. Through markets, technologies and business models that promote value to consumers (as indicated by their individual consumption and investment decisions) will thrive, while those that do not will fail. Markets also provide incentives for companies to innovate, to the benefit of consumers.

By allocating risks to market participants, markets provide financial incentives for market participants to make efficient decisions.

However, not all markets are well functioning. For example, to be effective, the energy market relies on risks external to it being manageable. Poorly functioning markets are unlikely to provide an efficient level of reliability at efficient cost.

Intervention-based approaches, on the other hand, tend to provide higher levels of certainty of reliable supply of energy, but, compared to a well-functioning market, are unlikely to deliver an efficient level of reliability at efficient cost. Agencies making interventions do not have the same financial incentives to make efficient decisions compared to market participants, and the risk of poor decisions is borne by consumers. Interventions also distort the functioning of the market, resulting in unintended consequences, including the perceived or actual need for greater intervention. There may therefore be long-term negative implications from intervention.

Therefore, there are different costs and benefits for market-based or intervention-based approaches. For example, centralised control over reliability provides a high degree of certainty that a reliable supply of electricity will be produced. However, such an approach will likely foreclose the considerable potential benefits of a well-functioning market, imposing costs and risks on consumers. But, in some instances (for example, where reliability concerns are manifesting in operational timescales or where the risk external to the energy market prevents it from being well-functioning), intervention mechanisms are likely to be appropriate in order to maintain the integrity of the electricity system.

## 4.3 Principles

In order to articulate how the Commission will consider balancing the criteria outlined above, the Commission has set out a number of principles to guide the development of recommendations on potential changes to market and regulatory frameworks that affect reliability in the NEM. These principles will be used to guide the Commission's assessment of the existing frameworks, as well as any potential modifications to, or additional, mechanisms that will be considered through this Review:

1. **Appropriate risk allocation:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a reliable supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. High risk to consumers is likely to be borne by consumers through higher prices while risk to market participants will only be passed on to consumers in terms of higher prices where competition permits. Under a centralised planning arrangement, risks are more likely to be borne by consumers.[54] Solutions that are better able to allocate risks to market

54 For example, in Western Australia, which has such an arrangement for reserve capacity, in 2016-17, there was an estimated 23 per cent (1061 MW) of excess capacity, which translates to $116 million. The costs of this are borne by electricity consumers and taxpayers. This translates to being one-fifth

participants, such as commercial businesses, who are better able to manage them are preferred, where practicable.

2. **Efficient investment in, and operation of, energy resources to promote a reliable supply**: Any framework for reliability should result in efficient investment in, and operation of, energy resources to promote a reliable supply of electricity for consumers. However, there are costs associated with provision of energy resources, which should be assessed against the value to consumers of having a reliable supply. Reliability frameworks should also seek to minimise distortions in order to promote the effective functioning of the market.

3. **Technology neutral:** Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

4. **Flexible:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving reliability outcomes over the long-term in a changing market environment. Regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating reliable outcomes where it is needed, while not imposing undue market or compliance costs on other areas.

5. **Transparent, predictable and simple:** Reliability frameworks should promote transparency as well as being predictable, so that market participants are informed about aspects that affect reliability, and so can make efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to implement, administer and participate in.

**Question 1 Assessment principles**

**(a) Do stakeholders agree with the Commission's proposed assessment principles?**

**(b) Are there any other relevant principles that should be included in the assessment framework?**

of the capacity in the WEM. Source: Government of Western Australia, Department of Finance, *Final Report: Reforms to the Reserve Capacity Mechanism*, 7 April 2016, p.3.

## 4.4 Assessment approach

The Commission intends to adopt the following approach to assessing the reliability market and regulatory arrangements, and developing recommendations as part of this Review.

1. **Define the issues**

   The Commission considers that the first step in the assessment framework is to define the problem or issues that have been identified in relation to reliability frameworks in the NEM.

   AEMO's latest *Energy Supply Outlook,* the Reliability Panel's Issues Paper for the *Reliability Standard and Settings review,* as well as the analysis contained in the Finkel Panel's *Independent Review into Future Security of the National Electricity Market* provide a good starting point for articulation of these issues.

   Chapters 5 through 7 of this report seek to articulate the Commission's preliminary views on the issues that may need to be addressed, as well as seeking stakeholder views on the materiality of these issues, and whether there are any additional issues.

   Further, the Reliability Panel is currently considering the existing reliability standard and settings. Detailed modelling of the electricity market will inform the Reliability Panel's review. The modelling involves five principal stages: modelling to determine the market price cap; forecasting of reliability under the status quo reliability settings; assessment of the suitability of the current level of the reliability standard; modelling to review the suitability of the market price floor; and assessment of the effect of a reduction in the market price cap. The outcomes of this modelling will be an important input into the Commission's review, in order to better understand the materiality of issues related to the reliability standard and settings.

   In addition, AEMO is currently preparing advice for the Commonwealth Government on the adequacy of dispatchable generation in the NEM. This will further inform our assessment of the issues, as well as potential solutions to these issues, and we are working closely with AEMO on this.

2. **Determine the options available**

   The AEMC's Review will identify the changes to market and regulatory frameworks that will be required to address the issues identified through the above process. The Review will consider both modifications to existing, as well as potentially new, mechanisms relating to the market- and intervention-based frameworks. It will also consider how these elements could address reliability in both the short- and long-term.

   These options will identify potential changes to the existing reliability frameworks that could better allow for efficient investment, retirement and operational decisions to be made, ultimately resulting in an adequate supply of dispatchable energy.

3. **Assess the range of options against the NEO and guiding principles**

   Any recommendations for potential changes to market and regulatory frameworks developed by the Commission will need to result in net benefits to the market and promote the long-term interests of consumers, consistent with the NEO. The Commission's assessment of the options, and the development of recommendations in this Review will also be guided by the framework principles set out above.

**Question 2 Assessment approach**

**Are there any comments, or suggestions, on the Commission's proposed assessment approach?**

# 5 Incorporating variable renewable energy into the NEM

This chapter discusses other aspects of reliability in the NEM and raises questions on topics on which the Commission would like stakeholder feedback. In particular:

- section 5.1 discusses implications of having a higher penetration of variable renewable energy in the NEM
- section 5.2 discusses the role of credible contingencies in the context of reliability
- section 5.3 discusses transmission frameworks.

## 5.1 Incorporating variable renewable energy in the NEM

Renewable, intermittent generation - be it at large-scale such as wind or solar farms, or at the residential level such as small scale PV systems - has implications for how the NEM operates. Intermittent generation is, by definition, not dispatchable. At low levels of penetration, those challenges may not be significant. However, as the share of intermittent generation continues to rise, it may start to affect the reliability of the system.

For example, in the past it was relatively easy to forecast the supply of dispatchable generation and expected consumer demand. However, unlike traditional generation sources, intermittent generation such as wind and solar is highly dependent on weather patterns, which may be difficult to predict with great accuracy at a particular point in time. Similar shortcomings may be present for hydro generation in periods of drought, also impacting reliability. These shortcomings are exacerbated during extreme weather conditions, which can also affect thermal plants, for example, resulting in a potential reduction of their available capacity at high ambient temperatures.

Similarly, increases in distributed energy resources, particular solar PV which is also intermittent, has occurred without a corresponding increase in the visibility of where these resources are located. This has also increased variances in short-term grid demand.

Further, since these generation sources depend on weather, they have more variable *availability* than traditional sources of generation, which has implications for operation of the power system. For example, increases in solar PV reduces operational demand at times, which leads to increased demand variation within a day.[55]

55 This has implications for frequency control arrangements, which are being considered in the Commission's *Frequency control frameworks* review.

### 5.1.1 Forecasting

**Solar and wind forecasting**

A key component affecting how intermittent generation is factored into power system operations is the forecasting of the availability of this generation.

AEMO currently uses the Australian Solar Energy Forecasting Systems (ASEFS) and the Australian Wind Energy Forecasting Systems (AWEFS) to forecast the potential output of wind and solar generation.

ASEFS is designed to produce solar generation forecasts for large solar power stations and small-scale distributed photovoltaic (PV) systems, covering forecasting timeframes from five minutes to two years.[56] The system has been delivered in two phases:

- ASEFS phase 1 involves the production of solar generation forecasts for large solar power stations, defined as greater than or equal to 30 MW registered capacity. Phase 1 commenced operation on 30 May 2014. It uses a combination of statistical methods and numerical weather prediction-based models, and uses the following inputs to produce solar generation forecasts for large solar power station for the dispatch, five-minute pre-dispatch, pre-dispatch, short-term-PASA and medium-term-PASA timeframes:
    - Real time Supervisory Control and Data Acquisition (SCADA) measurements from the solar power station.
    - Numerical Weather Prediction data from multiple weather data providers.
    - Standing data from the solar power station as defined in the Solar Energy Conversion Model.
    - Additional information provided by the solar power station, including inverters under maintenance and upper MW limit on the solar farm.
- ASEFS phase 2 involves production of solar generation forecasts for small-scale distributed PV systems, defined as less than 100 KW system capacity. Phase 2 commenced operation on 30 March 2016. This uses the same methods as phase 1 but also uses physical methods. It uses the following inputs to produce aggregated regional solar generation forecasts for small-scale PV systems for the pre-dispatch and short-term PASA timeframes:
    - Numerical Weather Prediction data from multiple weather data providers.
    - Output measurements from selected household rooftop PV systems from PvOutput.org.

56 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting.

- Static data from selected systems from PvOutput.org, such as inverter size and model.
- Aggregate kilowatt capacity by installed postcode for small-scale solar systems as recorded by the Clean Energy Regulator.

Both the ASEFS and AWEFS were established in response to the growth in intermittent generation in the NEM, and the increasing impact this growth was having on NEM forecasting processes.[57]

Similar to the ASEFS, the AWEFS aims to provide better forecasts that will drive improved efficiency of overall NEM dispatch and pricing, and permit better network stability and security management.[58]

AWEFS uses a number of inputs to forecast wind generation, on the same timeframes as the ASEFS phase 1, specifically:

- Real time SCADA measurements from the wind farms.
- Numerical Weather Predictions from weather forecasters from around the world.
- Standing data from the wind farms.
- Availability information provided by the wind farms, that includes turbines under maintenance and upper MW limit on the wind farm.

As discussed in AEMO's rule change request on the *Declaration of Lack of Reserve conditions*, it is presently analysing the historical short-term accuracy of the AWEFS and ASEFS and intends for the findings of this analysis to lead directly into AEMO's development of the new LOR guidelines if the rule is made by the Commission.[59] The Commission will use the outputs of this analysis as an input into this Review.

**Distributed energy resources**

The challenges are similar in the case of distributed energy resources. As an increased penetration of distributed energy resources occurs, AEMO considers that it needs more information about where distributed energy resources are in order to help manage the power system in a secure and reliable way. AEMO currently has a lack of visibility of a large number of distributed energy resources, which is impacting on its forecasting.

57 See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting.

58 The Commission is aware that the AWEFS has recently been raised as an issue in relation to how this has been used as an input into the causer pays methodology for recovery of frequency control ancillary services (FCAS). The Commission considers that this issue is out of scope for this review, although obviously, still relevant. While we understand that the forecasting errors in the AWEFS have been resolved, the Commission notes that this change has been implemented relatively recently.

59 See: http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions.

Without proper visibility of distributed energy resources with current forecasting methodologies, AEMO cannot forecast the demand and supply balance as accurately as it could when energy was primarily supplied by thermal generators.[60] This leads to unexpected shortfalls, which are difficult for AEMO to manage through its current processes. Unanticipated shortfalls may not leave enough time for an adequate market response and intervention mechanisms are not as effective when shortfalls are not expected, as discussed in chapter 7. As a result, AEMO's ability to manage reliability of the power system is being affected. Uncertainty of output means that forecasts and processes may need to be more flexibility to account for the lack of visibility of distributed energy resources.

AEMO is currently, or has recently considered, ways to improve its visibility of distributed energy resources:

- AEMO’s demand-side participation guidelines will require registered participants to submit demand-side participation data annually at the national metering identifier (NMI) level from April 2018.
- AEMO is also undertaking a range of work in the context of distributed energy resources and power system security, including its visibility of distributed energy resources project.[61]

In its recent *Distribution market model* project the Commission highlighted that there is a need to improve how distributed energy resources interact with the wholesale market. Stronger coordination relies on all relevant parties having sufficient information available to them and for this information to be reflected in price signals that reflect the value of providing all possible services, so that buyers and sellers of those services can make efficient investment and operational decisions.[62]

It also noted that the dispatchable capacity can be supplied through:

- generation, including large-scale coal, gas and hydro plants, as well as storage (either pumped hydro or batteries)
- demand response and other demand-side mechanisms, for example, when customers are paid to curtail their electricity consumption they respond to price signals or if they have entered into some control arrangements with their retailer.

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60 The recent announcement by the COAG Energy Council to establish a national register for distributed energy resources (solar generation and batteries) to be administered by AEMO will assist with this. See: http://www.coagenergycouncil.gov.au/publications/energy-market-transformation-bulletin-no-05-%E2%80%93-work-program-update.

61 See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO-FPSS-program----Visibility-of-DER.pdf.

62 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model.

In addition to the above, there are also a number of *other* drivers associated with the growth of intermittent generation that have the potential to affect reliability in the NEM in the long term:

- investment and operational incentives and disincentives which could be the result of policy uncertainty or potentially, existing price settings[63]
- the uptake of the demand side, particularly demand response in the NEM.[64]

As noted above, AEMO is already developing forecasting models to more accurately forecast wind and solar. Existing price settings are outside of the scope of this Review at this stage as they are being assessed in the Panel's *Reliability standard and settings* review. If the Reliability Panel's review identifies any issues with the current settings, its findings will inform this Review.

**Question 3 Forecasting**

**(a) What are stakeholders' views on the variances occurring in forecasting? Could these variances be minimised through more sophisticated forecasting techniques?**

**(b) Are forecasting errors impacting on NEM reliability?**

Notwithstanding the above, there are a number of potential options to better incorporate intermittent generation within the context of an reliability framework, some of which are outlined below. These options will need to be carefully considered and their suitability in the context of the existing characteristics of the NEM and the reliability framework will need to be assessed.

### 5.1.2 Outcomes to better accommodate fluctuations in supply

In a world where there is high penetration of intermittent generation there will need to be better accommodation of fluctuations in supply. There are a number of ways to achieve this:

- one option is to consider the need for more dispatchable capacity to be brought forward to the market to complement the increasing proportion of intermittent supply or
- another option (which is not mutually exclusive from the previous option) is to increase the diversity (location or technology) of flexible sources of energy, which can accommodate fluctuations in supply from other intermittent generation.

The Finkel Panel report, *Independent Review into the Future Security of the National Electricity Market*, concluded that if new dispatchable capacity is not brought forward

63 Investment, retirement and operational incentives are discussed further in chapter 6.

64 Discussed below in section 5.1.3.

to the market soon, the reliability of the NEM will be compromised. The Finkel Panel's conclusion was underpinned by a number of submissions which raised concerns around the need for more dispatchable capacity to complement a rising proportion of intermittent generators.[65] In particular, the Finkel Panel recommended adopting a Generator Reliability Obligation, discussed in Box 5.1. Progression of the Generator Reliability Obligation is within scope of this review.

**Box 5.1 Generator Reliability Obligation[66]**

The Finkel Panel recommended the adoption of a new Generator Reliability Obligation, which they envisaged as consisting of new obligations for intermittent (otherwise known as variable renewable energy) generators connecting to the NEM, to ensure reliability is maintained.

The Finkel Panel recommended that as part of this measure, the market bodies[67] should undertake regional reliability assessments to determine the minimum dispatchable capacity required for each region to maintain system security and reliability, and in doing so, should consider a number of factors, including:

- total variable renewable energy generation as a proportion of dispatchable generation
- network strength
- the extent of variation in variable renewable energy generation
- interconnections with other NEM regions
- load profiles
- wholesale and contract market considerations
- expected future trends.

The Finkel Panel recommended that new generation projects should be obliged to also bring forward new dispatchable capacity to regions where dispatchable capacity approaches the determined minimum acceptable level. It proposed that this obligation should be expressed in terms of a percentage of the new intermittent generator's nameplate capacity able to be dispatched for a required time period, and need not be located onsite.

Following the release of the Finkel Panel report and concerns about the continued retirement of thermal generation, the Hon. Josh Frydenberg, Minister for the

65 Finkel Panel, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p. 98.

66 Finkel Panel, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p. 99.

67 The AEMC, the AER and AEMO.

Environment and Energy, tasked AEMO with identifying the existing and potential loss of continuous dispatchable base load generation and to advise the government on how best to make sure that new, continuous dispatchable power is provided.[68]

AEMO's advice is expected to recommend optimal levels of dispatchable capacity required in the NEM and will inform this Review, in particular, in assessing the options for making variable renewable energy more dispatchable. The AEMC is also expecting a rule change from the COAG Energy Council on this matter, following advice from AEMO on what the optimal levels of dispatchable capacity are and the conclusion of the Reliability Panel's *Review of the reliability standard and settings* review.[69]

The Commission is interested in stakeholders' views on what changes to the framework to facilitate additional dispatchable generation, or facilitation of more flexible energy sources, or a combination of both, can achieve the aims of better incorporating intermittent generation into the NEM, without compromising reliability. Views on this will inform considerations of any such Generator Reliability Obligation.

There are already a range of views out there in the market, for example:

- Bloomberg New Energy Finance's (BNEF) New Energy Outlook considers that in the future in Australia the electricity mix will be dominated by the continued rise of consumer driven behind-the-meter PV and storage, which will make up 47 per cent of all new capacity additions over 2016-40. Together with demand response, behind-the-meter assets will make up 45 per cent of total power capacity in Australia by 2040. Despite the loss of coal, BNEF consider that the system will maintain security of supply as pumped hydro, batteries, gas and demand response are all added to support the uptake of variable wind and solar.[70]

- AGL proposed that renewable generators could partner, through direct or indirect means, with complementary 'firm' capacity. In the NEM framework, there is no firm access and care would be needed to consider how to provide firm capacity that was unlikely to be constrained off by transmission.[71]

Some stakeholders have observed that some overseas jurisdictions have recently implemented types of capacity mechanisms to address similar concerns. Capacity mechanisms generally operate where generators receive two forms of payment, one for energy produced and another for the level of generation capacity offered. Capacity mechanisms require a central planning agency to estimate the required capacity needed in order to achieve an efficient outcome. Retailers are then required to purchase from generators the share of the capacity determined by the planning agency related to

68 The press conference transcript may be accessed from https://www.pm.gov.au/media/2017-06-20/press-conference-hon-josh-frydenberg-mp-minister-environment-and-energy-and-senator.

69 COAG Energy Council, 12th Energy Council Meeting Communique, 14 July 2017.

70 BNEF, New Energy Outlook 2017: Asia-Pacific, June 2017, p. 91.

71 See: http://www.environment.gov.au/submissions/nem-review/agl.pdf.

their customer load. Customers bear the risk of decisions by that planner such as too little or too much capacity being purchased.

In both energy-only markets[72] and capacity mechanisms the price that generators receive for energy produced is determined by forces of supply and demand in order to achieve an optimal and efficient outcome. However, in capacity markets the additional price that generators receive for capacity offered is centrally determined. The efficient operation of capacity markets relies on the accuracy of the centrally determined level of capacity payments. Payments must be set at a level that encourages investment sufficient to meet demand growth but not so high as to result in excess profits to generators at the expense of consumers.

**Question 4 Options to accommodate intermittent generation**

**(a) Do stakeholders consider that facilitating additional dispatchable generation, or facilitation of more flexible energy sources, or a combination of both, can more easily achieve the aims of better incorporating intermittent generation into the NEM?**

**(b) What outcomes do stakeholders consider are necessary in order to better incorporate intermittent generation sources into the NEM, from a reliability point of view?**

**(c) What factors should be taken into account when considering a Generator Reliability Obligation?**

### 5.1.3 Wholesale demand response

A key to any flexibility of energy supply is demand response. Increasing the flexibility of the demand-side in the NEM, to make the demand-side more able to readily adapt to changes on the supply-side. For example, if the clouds blocked sun in South Australia and the output from solar PV farms decreased, mechanisms and price signals would exist such that large businesses would reduce their consumption, and so demand and supply would still be balanced. Such a response from the demand side is otherwise known as wholesale demand response.

There are a number of ways that demand-side can respond in the NEM, which would be considered wholesale demand response:

- A participant could become a market customer in the spot market either as a scheduled or a non-scheduled load. This would mean that they would be directly exposed to the spot price through the wholesale market. If spot prices were high, in order to reduce their exposure they could reduce their consumption. If the

72 Energy-only markets like the NEM are based upon spot pricing of electricity in which prices and volumes are determined by equilibrating bids with demand requirements. In pay-as-bid markets, prices are determined transaction by transaction on a continuous, bilateral basis. In electricity pools bids are aggregated and a single price is determined pricing-period by pricing period.

participant was largely covered by a hedge contract then when the spot price is above the value of energy to them, they could make more money by curtailing their consumption and retaining the contract payments.

- A customer could enter into an agreement with its retailer through either accepting a degree of spot price exposure; or allow the retailer to manage the spot price risk while the customer's demand response capability is valued through contracts. This allows retailers to offer a number of products and services that allow customers to participate in the energy market under a variety of different options, specifically:
  - Customers might be willing to accept full or partial exposure to spot market prices through a spot price pass-through contractual arrangement with a retailer. Customers may then undertake measures to manage this exposure. For example, they may engage energy management experts to manage their electricity price exposure through their energy use. However, participating in central dispatch large customers may lose some flexibility over their consumption decisions and may incur come costs to comply with requirements. This often discourages customers from pursuing this demand side participation avenue.
  - Another (weaker) form of demand response participation may include negotiating a time of use tariff with the retailer. Under this option customers are incentivised to shift their load from peak (high price) time periods to off-peak (lower price) periods.

The COAG Energy Communique of July 2017 noted that it will direct the AEMC to recommend a mechanism that facilitates demand response in the wholesale energy market, as recommended by the Finkel Panel.

The Commission notes that in 2016 it considered a specific demand response mechanism – see appendix B for more details. However, the NEM has developed since that time and it is worth considering wholesale demand response in the current context, that is, the need to maintain a reliable supply of energy.

Bloomberg New Energy Finance (BNEF) have recently undertaken some research into demand response in the NEM. It concludes that the key impediments for demand response in the NEM are a lack of access to wholesale markets and conflicting incentives for retailers. BNEF also conclude that the NEM is also missing the two key ingredients for widespread demand response present in other markets: capacity or availability payments[73] and participation by third-party aggregators. Instead, the

73 BNEF consider, based on its research, that the markets with the most demand response tend to have capacity (fixed payments to the participant for maintaining a certain MW capacity available for deployment for the duration of the contract, usually a period of months or years) or availability (payments made to participants for each available megawatt, for each hour that it is made available) payments since they provide revenue certainty.

NEM only currently incentivises non-dispatchable demand side participation, which is less valuable.[74]

This research suggests to the Commission that it is worthwhile exploring whether stakeholders consider there are barriers to demand response in the NEM, in the current environment. The Commission considers that there are potentially two issues that could exist:

- Increased vertical integration. This means that such companies manage their risks internally and may be faced with conflicting incentives. For example, at times of high spot prices retailers would have an incentive to offer customers demand response opportunities, but at the same time, generators have an incentive to offer capacity into the market to earn the high prices. Since vertically integrated retailers have invested in generation (which has a long life) they therefore may favour the revenue that can be earned by the generators, and so not engage in demand response. Since their consumers do not see wholesale price signals, there is limited ability for them to respond. Following the introduction of the competitive metering framework on 1 December 2017, the Commission considers that there will be an increase in advanced meters, thus creating more opportunities for retailers to offer such products, as the technology would be available to support it.

- The value of customer reliability - see Box 2.2 - is higher than the current market price cap. Therefore, although demand-side participants could respond, often their willingness to pay for energy, is higher than the price they are actually paying. This could suggest that raising the market price cap may result in more demand response, although the alternative is that it could increase the level of risk and not result in increased demand response.

The Commission notes that ARENA and AEMO are current trialing demand response (see section 7.3.3). All project proponents that receive funding from ARENA through this trial must share data, lessons learnt, insight and knowledge from their project. The AEMC is staying closely involved in this project. The knowledge and data shared from this project will be used to accelerate the creation of a competitive demand response sector, with an initial focus on reliability demand response. In particular, the knowledge sharing plan states that the trial "will assist the AEMC to understand the merits and design of potential market reforms to enable the expansion of demand response in Australia".[75] In particular, it will reveal understanding about barriers associated with the supply of demand response generally, and the existing RERT mechanism in particular, system changes, assessing the baseline, and the potential costs and benefits to participants (amongst other things).

The Commission will review these findings with interest, and incorporate them into this review. To the extent that stakeholders consider that there is anything additional,

74 BNEF, Demand response in Australia: an untapped response, May 24 2017.

75 See: https://arena.gov.au/assets/2017/06/20170607_DRKS_publicdiscussionpaper_PUBLIC.pdf.

beyond what will be revealed through this study, that may be useful for the Commission to know then we welcome submissions in this regard.

## 5.2 Credible contingencies and reliability

Some elements of the reliability framework are based around the concept of credible contingency events, generally the loss of large conventional generating units.

### 5.2.1 Credible contingency framework

NER clause 4.2.3(b) defines credible contingencies as a contingency event[76] the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances, including the technical envelope. They may be caused by events such as the loss of a single generator, a single load or a single line in the network.

The NER therefore provides guidance to AEMO as to which contingencies should be regarded as credible but leaves AEMO with some discretion. AEMO has the discretion to reclassify contingency events from non-credible[77] to credible when it considers that the presence of abnormal conditions (for example, several weather conditions) means that the non-credible contingency is now more likely to occur.

The concept of a credible contingency is a key concept in the NER, underpinning both the reliability, as well as the security framework. An example of the concept being used for security is that AEMO is required to maintain the power system frequency within the operational frequency tolerance band when credible contingencies occur, and must return the frequency to the normal operating frequency band within a specified time period (discussed further in section 5.2.3 below). Similarly, networks face a number of obligations to plan and operate their networks for credible contingency events.[78]

The concept of credible contingencies is used differently within the context of reliability. For example, definition of lack of reserve conditions as set out in NER clause 4.8.4 uses the term 'credible contingency', and provides further guidance about how this concept is used in this context, presumably to improve its applicability to the reliability framework.

### 5.2.2 Declaration of Lack of Reserve conditions rule change request

AEMO has recently submitted a rule change request to the AEMC relating to *Declaration of Lack of Reserve conditions*. In this rule change request AEMO notes that, in

76 Defined in NER clause 4.2.3(a) as being an event affecting the power system, which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission element.

77 Events which AEMO considers are not reasonably possible in the surrounding circumstances are known as non-credible contingencies. They may include events such as the simultaneous loss of multiple generators, or the loss of interconnection with a neighbouring region as a result of the loss of multiple transmission circuits.

78 For example, see NER clause S5.1.2.1.

relation to the lack of reserve 1 and 2 definitions, the simple criterion of credible contingency events is progressively becoming less relevant in the changing power system.[79] Instead, significant rapid deteriorations in short-term power system conditions now frequently occur due to non-contingency based variations. AEMO considers the key variables to be:[80]

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

The rule change request sets out that AEMO considers it essential to implement a more sophisticated warning and intervention trigger derived from its view of the probability of involuntary load interruptions. This probably would consider the variables listed above as well as traditional large contingencies. The proposed rule change would clarify the purpose of lack of reserve conditions and retain the present NER obligations upon AEMO to assess and declare them. The rule change request also proposes that the detailed definition of each level is moved out of the NER and transferred to an AEMO maintained public document, the "reserve level declaration guidelines". AEMO considers that this would allow them to employ a more sophisticated risk assessment measures and to improve the measures over time.

A consultation paper on this rule change request was published on 22 August 2017. It details that the definition of credible contingencies is outside the scope of that rule change request. Instead, it is being assessed through this Review. However, consideration of this rule change request and this Review will be coordinated.

### 5.2.3 Review of the Frequency Operating Standard

Similar issues have been raised by AEMO in the context of the *Review of the frequency operating standard,* which is currently being undertaken by the Reliability Panel. This review is being undertaken in two stages.

The Panel published an issues paper for this review on 11 August 2017, which set out a number of key issues for consultation. The paper noted that as part of stage one of the review, the Panel will consider the appropriateness of the current definition of the term 'generation event' in the frequency operating standard. This term is relevant to a discussion on credible contingencies. The frequency operating standard sets out how the frequency must be maintained (that is, within a band) under a series of different conditions of the system. One such condition is when a generation event (or load

79 AEMO, Lack of reserve declarations, Electricity rule change proposal, 1 August 2017, p. 4.
80 Ibid.

event) occurs. In other words, one part of the standard states that as a result of a generation event, or a load event, system frequency should not exceed the applicable frequency band for a certain period of time.[81]

Through the Reliability Panel, AEMO has raised a concern relating to the definition of the term "generation event" in the frequency operating standard. AEMO's concern relates both to the consistency of this definition between the frequency operating standard for the mainland and the frequency operating standard for Tasmania and the applicability of this definition to describe the characteristics of the current power system.

The term "generation event" is defined in the mainland frequency operating standard as:

> "a synchronisation of a generating unit of more than 50 MW or a credible contingency, not arising from a network event, a separation event or a part of a multiple contingency event."

And in the frequency operating standard for Tasmania as:

> "a synchronisation of a generating unit of more than 50 MW or a credible contingency event in respect of either a single generating unit or a transmission element solely providing connection to a single generating unit, not arising from a network event, a separation event or a part of a multiple contingency event."

AEMO elaborated on its concerns in its submission to the issues paper. AEMO considers that two aspects of the above definitions need to be addressed:[82]

- the reference to synchronisation, which it considers confusing and limited, and not reflective of the current generation mix
- a credible contingency (for generating units) as defined in the NER (as explained above) does not satisfactorily describe all kinds of rapid, unexpected generation events.

As the generation mix evolves to one of more intermittent generation, large ramps in generation over short periods from plant are possible, for example from solar during intermittently cloudy days. Generation from utility-scale solar plant in the NEM has been observed to change by up to 80-90 per cent of rated capacity in five minutes, or as much as 101 MW in five minutes for a 103 MW plant.[83] In this respect, AEMO considers that a significant reduction in output from a wind or solar farm over a short

81 See, for example: Reliability Panel AEMC, Application of Frequency Operating Standards during periods of supply scarcity, 15 April 2009.

82 AEMO, submission to issues paper for review of the frequency operating standard, 1 August 2017, p. 6.

83 Ibid.

period of time has a similar effect on frequency (and so frequency control) as the trip of a similarly sized synchronous generator, albeit over a slightly longer period of time.[84]

AEMO therefore considers that it is more appropriate to define a generation event as a large rapid unexpected change in generation output from a generator or set of generators resulting from a common event. AEMO identified two immediate options to address this, which are currently being considered by the Panel though its review.

Such issues as in this section (that is, the definition of a generation event) are out of scope for this review, but provide further examples of how the concept of credible contingencies is a fundamental term in the current NER framework for both security and reliability.

### 5.2.4 Potential issues

As noted above, AEMO has recently raised concerns that the concept of credible contingency may no longer be appropriate in the context of reliability and security outcomes in the current environment, where variances from demand and intermittent supply may be greater than the loss of a largest generator.

The Commission considers that the credible contingency definition is a fundamental concept throughout the NER, and underpins security and reliability frameworks. Therefore, the Commission recognises that significant additional analysis will be required when considering any changes: to assess the potential impacts, any unforeseen consequences, and any flow-on effects relating to costs.

The Commission understands that AEMO is currently in the process of scoping a larger work program to consider technical issues related to frequency control, and whether or not the current market frameworks are meeting the technical requirements as the energy market transitions.[85] This will be an important input into any progression of this issue.

The Commission also considers that there are likely to be different considerations for these definitions, depending whether or not they are being considered in the context of reliability or security. For example, the Commission understands the accuracy of forecasting for wind and solar is relatively accurate, and so these issues may not be so acute for reliability, where there is likely to be a bit more variance accommodated in the forecasts. In contrast, security outcomes, which require responses in seconds, any variances may be more severe in terms of outcomes.

The Commission is interested in any preliminary stakeholder views on these matters.

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84 The implications of the need for increased ramping requirements are being considered in the *Frequency control frameworks review.*

85 1. AEMO, Market Ancillary Service Specification, Issues Paper, 25 January 2017, p. 1.

**Question 5 Credible contingences**

(a) **Do stakeholders have any views on whether the existing credible contingency definitions may, or may not, be appropriate given the changing generation mix?**

(b) **What are the differences in the impact of the changes in the generation mix on these definitions? Do these differ depending on whether they are thought of as relating to 'reliability' or 'security'?**

(c) **In reviewing the appropriateness of these definitions, are there any particular principles or considerations that the AEMC should take into account?**

## 5.3 Transmission frameworks

The interconnected transmission network in the national electricity market (NEM) is important for facilitating a reliable supply of electricity to consumers and to support the NEM wholesale market by allowing electricity to be bought and sold across regions. Particularly relevant to reliability, interconnection between jurisdictions allows lower cost generation in one region to supply demand in other regions, and enables reserve sharing between regions, lowering the overall cost of meeting electricity demand.

### 5.3.1 Current transmission frameworks

#### Planning arrangements

Planning concerns the investment needs of the transmission network in general terms, rather than specific investment decisions. However, specific investment decisions by networks will be made as a result of planning.

Transmission network planning takes a number of different forms and covers a number of time horizons. Long-term planning takes a strategic view and focuses on long-term investment needs. Short-term planning has a focus on the near term and specific investment needs. Project specific planning relates to a particular investment need and culminates in an investment decision. As there are numerous planning horizons, each with a different focus, there are a number of outputs produced as part of the transmission network planning process. Responsibility for different elements of the planning process rests with different parties, depending on the form of planning undertaken. Planning also takes place at a national and jurisdictional level with this determining which body undertakes the planning work.

AEMO, as national transmission planner (NTP) and jurisdictional planning bodies therefore share responsibility for transmission network planning. Jurisdictional planning bodies are, in most cases, the local transmission network service provider (TNSP) except in Victoria.[86]

AEMO as NTP conducts long-term strategic planning across the NEM. This planning process results in the publication of the National Transmission Network Development Plan (NTNDP), covering a horizon of 20 years. The NTNDP uses a range of scenarios to examine the efficient development of the national transmission grid, with a particular focus on major transmission flowpaths including interconnectors.

Short-term planning is undertaken by the jurisdictional planning bodies. In particular, Part B of Chapter 5 of the NER sets out planning and reporting requirements for network service providers. Under these requirements, a TNSP is to undertake an annual planning review to identify emerging network constraints expected to arise over a ten-year planning horizon. The results of a review are then published in an annual planning report, which must (amongst other things) set out what the TNSP is doing to meet its reliability standards.

TNSPs also undertake project specific planning through a cost-benefit test, which considers the benefits to market participants and consumers of a particular investment. The most recent version of the cost-benefit test, the regulatory investment test for transmission (RIT-T), was implemented in August 2010. Under the RIT-T, TNSPs are required to assess the efficiency of proposed augmentation[87] investment options (that exceed $6 million) by estimating the benefits that would result for market participants and consumers, and comparing these to the associated costs. The purpose of the RIT-T is to identify the transmission investment option which maximises net economic benefits and, where applicable, meets the relevant reliability standards. If a proposed investment passes the criteria governing the RIT-T, the TNSP is able to proceed with the investment, and this will be funded by market customers through transmission use of system (TUOS) charges.

The primary purpose of the current framework of annual planning reports and RIT-Ts is to support the planning of, and decisions on investment in, a network by:

- creating incentives for, and a framework within which, TNSPs can consider potential non-network solutions to network constraints or limitations
- establishing clearly defined planning and decision making processes to assist TNSPs in identifying the solutions to network problems in a timely manner

86 In Queensland the jurisdictional planning body is Powerlink; in NSW and the ACT it is TransGrid; in Victoria it is AEMO as part of its declared network functions under the National Electricity Law; South Australia it is ElectraNet; and Tasmania it is TasNetworks.

87 The AEMC in the *Replacement expenditure planning arrangements* rule change has made a rule that will require that a RIT-T for replacement expenditure from 18 September 2017. Replacement projects that have reached a "committed" stage before 30 January 2018 will not be subject to the RIT-T requirement. For more information see http://www.aemc.gov.au/Rule-Changes/Replacement-Expenditure-Planning-Arrangements.

- providing transparency on network planning activities to enable stakeholder engagement with those activities in order to support the efficient investment in the network.

Historically, most intra-regional transmission investments have been to meet the relevant jurisdictional reliability standards, while interconnector upgrades (that is, the construction of transmission infrastructure connecting two regions) has been justified on providing a net market benefit, which could include the sharing of reserves.

### Open access system

The current transmission framework in the NEM can be summarised as an **open access system.** The focus of TNSPs, including their operation and investment decisions, is to deliver a reliable supply to consumers and to make offers to connect to generators and loads that wish to connect to their network. TNSPs must make investments or procure services to meet the relevant jurisdictional reliability standard.[88] The development of transmission infrastructure to enable the export of energy from generators will therefore only occur to the extent that is necessary to ensure consumers receive a reliable supply of electricity.

Under this open access system, a generator has a right to connect to the transmission network but there is no guarantee they will be able to sell their output. A generator's right to use the transmission network, and so earn revenue, is based solely on whether or not it is dispatched by AEMO in the wholesale market. Dispatch of electricity is determined by dispatch offers of generators and the level of network congestion, as explained in chapter 2.

Therefore, because there is an obligation on transmission businesses to reliably supply their customers, it is customers who fund investments in the transmission network that enable export of energy from generators, and relieve congestion where necessary. The costs of the assets necessary to provide a reliable supply are recovered solely from load (that is, customers).[89]

As generators have no access right to the transmission network, that is, there is no guarantee they will be able to sell their output, they only pay charges relating to the cost of their immediate connection to the shared transmission network, the charging regime for generation can be characterised as a "shallow" connection charging approach.

88 Network reliability standards relate to how transmission and distribution networks can withstand risks without consequences for consumers and guide the level of investment that networks undertake. These standards are set by state and territory governments. These standards generally make sure there is a level of redundancy on the system implying that the supply of power to total load (that is, customers) will be robust in the event of a certain level of risk, or contingency.

89 Generators pay a shallow connection charge covering the equipment required to connect them to the network, including for those assets that are part of the shared transmission network.

### 5.3.2 Coordination of transmission and generation investment

The Commission is currently considering issues associated with the coordination of transmission and generation investment (namely, transmission planning, transmission charging and access arrangements) through Stage 2 of the *Reporting on drivers of change that impact transmission frameworks* project.[90]

An approach paper for this review was published on 22 August 2017. It provides detail on the issues that will be examined in the second stage of this Review, as well as identifying potential options to address these issues. An options paper will be published in November 2017, which will narrow down the various options under consideration and provide more detail on each chosen option.

Therefore, the Commission considers that transmission planning, transmission charging and access arrangements are out of scope of this Review, since they are being considered through this other project. These topics do influence generation investment and operational decisions, and so can be considered to tangentially relate to reliability. Therefore, the Commission will coordinate consideration of these two projects. However, interconnector investment, which allows sharing of reserves, is within scope of this Review as discussed below.

### 5.3.3 Implications for interconnection

The growing share of electricity generation coming from renewable energy sources, as discussed in section 3.2.2, may increase the potential benefits for interconnection. This is because:

- sources of renewable energy are often further removed from centres of demand than conventional generation
- the potential for price separation between regions is likely to increase as a result of lower-cost renewable energy in some regions
- the intermittency of renewable energy sources such as wind and solar requires sufficient complementary generation from other power sources in order to secure a reliable supply. This complementary generation may be provided by a generator in another region.

So, interconnectors can be considered a partial (but not perfect) substitute for dispatchable capacity in relation to reliability. Instead of investing in generation capacity in a particular region, it may be cheaper to upgrade an interconnector in order to allow sharing of reserves.[91]

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90 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi.

91 AEMO and ElectraNet, South Australia - Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Assessment Conclusions Report, p. 100.

The current regulatory framework does allow for benefits associated with sharing of reserves to be taken into account in the RIT-T, specifically modelling done under the RIT-T must be undertaken meeting minimum reserve levels.[92] Further, interconnectors are considered in various studies associated with the reliability standard. For example, the Reliability Panel considers interconnectors when assessing the reliability standards and settings.

The Commission is interested in stakeholder views on what role interconnectors can play in relation to reliability.

**Question 6 Interconnector**

**(a) What role can interconnectors play in relation to reliability?**

**(b) What factors should the Commission consider in this regard?**

92 AER, Regulatory investment test for transmission, p. June 2010, clause 21.

# 6 Market aspects of the reliability framework

This chapter discusses the market aspects of the reliability frameworks in the NEM and raises questions associated with this part of the framework that the Commission would welcome stakeholder feedback on. In particular:

- section 6.1 discusses the wholesale market, including the role of the reliability settings
- section 6.2 discusses the contract market
- section 6.3 discusses external factors influencing investment and operation
- section 6.4 discusses the mechanisms available for informing the market of future reliability considerations

## 6.1 Wholesale spot market framework

Underpinning the wholesale spot market framework is the economic principle that the most efficient investment decisions are made if market participants can make their own decisions on whether to start up or shut down and the amount of generation to dispatch in response to price signals. A market price provides the signals needed for investors to make their own, informed investment and retirement decisions.

Since the NEM was established in 1998 the pricing framework has included a maximum limit (cap) and minimum floor on wholesale prices. Collectively, this cap and floor establish an envelope within which prices can vary.

**Box 6.1 Reliability Panel's *Reliability Standard and Settings* review**

The Reliability Panel is currently conducting a review of the reliability standard and reliability settings that will apply on and from 1 July 2020.[93] Under the NER this review must carried out every four years. This regular review allows the Panel to consider whether the current levels of the reliability standard and reliability settings remain suitable for expected market conditions, or whether changes should be made to make sure these mechanisms continue to meet the requirements of the market, market participants and consumers. The market environment and market arrangements are constantly evolving. Periodic review of the reliability standard and settings allows the potential impacts of changes to be assessed.

The current reliability standard sets out that there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of annual demand for electricity is expected to be supplied. The standard in fact specifies the maximum expected unserved energy or the amount of electricity

93 Clause 3.9.3A(d)

demanded by consumers which is at risk of not being supplied. It is currently set at 0.002 per cent of each region's annual energy consumption in a financial year.

The reliability standard is an expression of the maximum allowable level of electricity at risk of not being supplied to consumers in any NEM region. It is also consumer-focussed; the level of maximum expected USE is based on comparing the benefits of a more reliable power system to consumers against the costs incurred by consumers in providing that level of reliability.

The Commission recognises that while setting the reliability standard and the reliability settings at an appropriate level, through forecasts and expectations of future unserved energy, can *influence* investment in the market, they alone may not sufficient to make sure that investment to achieve the desired level of reliability actually occurs. As noted above, there are many other factors that have an equally significant impact on participant investment decisions, which are discussed elsewhere in this section.

The scope of the Panel's review is to:

- consider whether the level of the existing reliability standard remains appropriate for the market conditions expected from 1 July 2020
- if the Panel considers that the level of existing reliability standard is not appropriate for the expected market conditions from 1 July 2020, recommend a revised reliability standard that should apply from 1 July 2020
- consider whether the existing reliability settings remain appropriate for the market conditions expected from 1 July 2020
- if the Panel considers that the level of an existing reliability setting is not appropriate for expected market conditions from 1 July 2020, recommend the level appropriate to that reliability setting that should apply from 1 July 2020 and
- propose changes to the NER to implement any recommended changes arising from the review.

A key part of the Panel's analysis is to undertake detailed modelling that will inform the review. This modelling, and analysis will be used as an input into this review. If the Panel's analysis suggests that it is necessary to do so, then this Review will consider whether there are any other additional structures or fundamental changes that could be made to the reliability settings that would provide better price signals of when there are shortfalls of reserves to try and better incentivise investment, retirement and operation decisions.

It is important to note that while retailers and some large industrial consumers are exposed to variable prices of electricity in the wholesale market, most consumers - for example, small businesses and residential consumers - are not directly exposed to spot market prices. Rather, retailers participate on behalf of consumers, that is, retailers purchase electricity on the spot market and manage price risk through participation in the parallel financial contracts market.

As discussed in chapter 2, markets rely on the presence of willing participants, both buyers *and* sellers. A principal consideration for the participants is the risk that they are exposed to through the wholesale spot market, which in the NEM is determined by the reliability settings. Placing limits on participants' exposure to very high and very low prices to protect the integrity of the market is a feature of markets in many sectors. This is particularly important given the physics of electricity supply systems that require the instantaneous matching of demand and supply.

However, as we move to a market where there is significantly more flexibility and responsiveness, both on the demand-side, as well as the supply-side it will be important to consider whether or not these price limits remain appropriate. This is the focus of the Reliability Panel.

Given the above, it is worth noting that the higher the market price cap, the riskier it is for generators to contract for a large portion of their plant. In the case of network constraints or outages, it will still have to pay out the high price difference. Similarly for retailers the higher the market price cap, the higher the level of contract cover sought. A higher market price cap could create an incentive for more physical generation plant to be installed, or available to cover a greater level of sought after contract positions. This may increase the level of plant in excess of consumer demand (i.e. reserve) which is a key factor in delivering a reliable supply.

Finally, there may be concerns about uncertainty relating to the prices that participants receive from the spot market. These concerns should be managed by such participants entering into contracts in order to hedge these risks. However, for generator participants that have relatively long start-up times, more volatile prices may be concerning. Such concerns were part of the driver for the Finkel Panel recommending AEMO and the AEMC consider the suitability of a day-ahead market. Such considerations will also be considered through this Review.

In particular, it is worth noting that there are numerous design options for a day-ahead market.[94] The Commission considers that it is particularly important to be clear on what the objective is that is trying to be met, prior to thinking about what the best mechanism is to address it. Typically, the objective is set around making sure that there is sufficient thermal units present in the wholesale market, in order to have enough generation to meet demand.

This objective could be met in a number of ways, and through a number of mechanisms, all of which could be considered to be 'day-ahead markets'. Some of these increase the incentives to participants to offer into such a market, while others give more powers to the market operator in order to make sure that they can ‘schedule’ on

94 This was recognised by the Finkel Panel who noted that any further consideration of a day-ahead market would require detailed cost-benefit analysis, including in relation to the nature of changes to the existing real-time and contract markets.

such plants. For example, possible solutions could comprise variations of a number of the below mechanisms:

- Forecasting – refinements to the forecasting process undertaken by the market operator in order to get more inputs into demand forecasting, which would have the effect of improving pre-dispatch (that is, forecast) outcomes.
- Limits on rebidding, such as implementing gate closure, or a transaction fee for rebids. Such mechanisms could encourage more efficient or accurate bids to be made into the wholesale market earlier.
- Multi-part bidding, into a multi-settlement spot market – generators bid in multi-part bids (for example, start-up and then energy costs), which could then be optimised across a number of periods.
- Short-term (ranging from hours-ahead to days-ahead) markets (either capacity or financially based contract markets), which range in design from being compulsory or voluntary, selling standardised or varying products.

The Commission plans to consider a range of these options throughout the course of this Review, and will draw upon work being done, and issues raised, in the *Five minute settlement* rule change request that relates to this. Box 6.2 describes an example of a day-ahead market, Electric Reliability Council of Texas (ERCOT) in Texas. While ERCOT can be considered to be an energy-only market, there are many differences between it and the NEM. As a result, comparisons should be approached with caution.

**Box 6.2 Day-ahead markets in Texas**

ERCOT has a voluntary, financially-binding forward electricity day-ahead market.

However, ERCOT also has a separate mechanism: Reliability Unit Commitment (RUC) process. ERCOT uses the output of the day-ahead market to assess whether there will be sufficient committed generation, and this process then seems to continually iterate until real time. Generators have the ability to either self-commit (and just make energy offers) or to make a three-part offer (start-up costs, an offer associated with running at minimum load and offers for output in excess of minimum load).

In this way, ERCOT makes commitment decisions so that there will always be sufficient plant committed in real time to meet its forecast of demand. It also procures spinning and non-spinning reserves (which it describes an ancillary services) – to give it some margin over and above its demand forecast.

Participation in the day-ahead market is voluntary in that it’s possible to contract outside the day-ahead market. It’s also possible to go into the real time market completely uncontracted. Contracted generation is expected to self-commit. To the extent that ERCOT incurs costs in committing uncontracted generation, these are recovered from uncontracted load. Any costs associated with ERCOT unnecessarily committing plant as a result of getting the demand forecast wrong are recovered from all customers through an uplift charge.

Source: ERCOT's website, accessed from http://www.ercot.com/services/training.

Importantly, any outcomes in the spot market are reflected in the contracts market, since this is a derivative of these prices. This is a key driver of investment, retirement and operational decisions.

## 6.2 Contract market

As discussed in chapter 2, the contract market is the key underpinning driver of investment in the NEM. The contract market has been an integral part of the NEM market design since its inception, contributing to reliability in a number of ways. A liquid contract market provides longer-term price signals for market participants to make efficient investment, retirement and operational decisions by providing information on expected future market prices as well as providing a mechanism through which new generation can be financed. As noted in chapter 2, vertically integrated businesses effectively 'contract' internally.

The contract market also provides a mechanism for retailers and other market participants to manage exposure to wholesale price volatility and uncertainty associated with the wholesale spot market options. By providing options for greater certainty for retailers, generators, major industry and some consumers of electricity, the contract market provides a market-based mechanism to support efficient investment and operation over time.

Generators, through long-term off-take contracts (known as power purchase agreements), can obtain a degree of revenue certainty and secure project finance, but these provide weaker investment and operational incentives to deliver a reliable supply than firm hedge contracts. On the other hand, retailers use hedge contracts to deliver price stability for consumers and secure financing for their own operations.

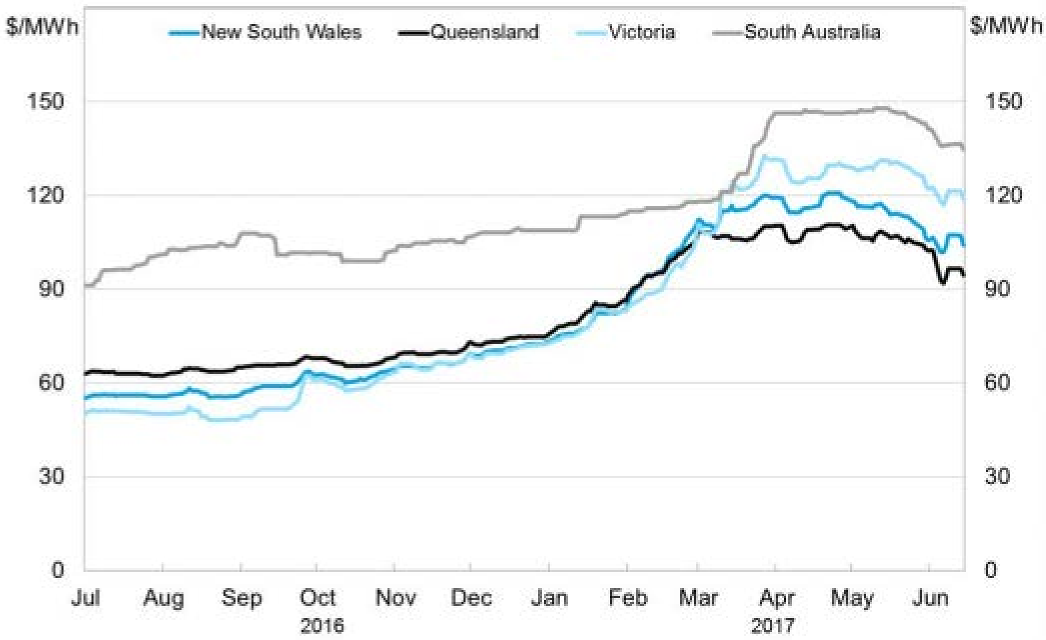
Contract market liquidity is important for the effective functioning of the NEM, with many factors impacting on its liquidity.

In the *2017 Retail Competition Review* the Commission discussed the effect that thelarge-scale Renewable Energy Target (LRET) is having on the contract market. New, intermittent generation is adding to the physical capacity in the system, but is not resulting in a corresponding increase in the supply of firm-capacity hedge contacts. Further, the new generation incentivised by the LRET has contributed to the retirement of older generation plants that were supplying firm-capacity hedge contracts. Consequently, the supply of hedge contracts is diminished, increasing the cost of electricity wholesale contract prices, as shown below.

Figure 6.1 shows that if a contract was purchased to fix the wholesale price for the 2018 financial year (that is, 2017-18) at the start of October 2016, prior to the announced closure of Hazelwood, it would cost just over $60/MWh in NSW, Victoria and

Queensland, and around $100/MWh in South Australia. However, by the start of May 2017, after Hazelwood was retired, the same contract cost over $100/MWh in NSW, Victoria, Queensland (an increase of over 60 per cent), and just under $150/MWh in South Australia (an increase of around 50 per cent).

**Figure 6.1 Prices of baseload swap electricity futures contracts**




Source: ASX Energy

With increasing levels of intermittent generation in the NEM, the contracting needs of participants buying the electrical output from these intermittent sources is also adapting and changing to reflect and manage the risks associated with the uncertain nature of this generation - see Box 6.3.

**Box 6.3 Case study: wind generation and contracting**

The merits of wind generation can be considered through the expected energy price it would receive. This can be expressed as the average spot price and premium / discount on that price. The former is associated with the market outlook as influenced by issues such as gas costs, and the latter with the profile of generation compared to demand.

The profile and nature of output from intermittent renewable generation means that wind generation has, and can be expected to have, dispatch weighted prices that are less than the average spot price at its point of connection.[95] This 'dispatch weighted price'[96] for wind generation as a percentage of the average spot price for 2015/16 varies across the NEM. For example, this discount is

95 Regional spot price x marginal loss factor.

96 The DWP is defined as generation revenue divided by generation quantity.

expected to be around 25 per cent in South Australia over the next 20 years.

The output from the same intermittent generation can vary greatly on all time horizons (from one five minute period, hourly, daily, monthly and yearly). This variability means that wind generators do not typically enter into firm hedge contracts, and instead sell discounted contracts. There are a number of ways that wind generation could firm up its output in order to provide a firm or relatively firm product that has more value and less compared to the alternative:

- Intermittent generation firming hedge products, generally premium cap type revenue structures where volumes can change as wind output alters.
- Caps, typically obtained through the over the counter market or electricity futures markets, can provide risk protection associated with the intermittent output not being there at times of high pool prices.[97]
- Weather insurance products, which can be low wind and/or high temperature, are typically related to the specific weather risks facing a participant.
- Use of physical generating assets such as hydro, open-cycle gas turbine (OCGT), diesel, that is, vertical integration. As a direct response to opportunities and market volatility most, if not all, of the major participants in the NEM either own or control output from physical generation assets.

Out of all the firming options previously identified, with energy and cap prices at current levels and the challenge of finding alternative competitive longer term firming products, the lowest cost for firming intermittent generation is through the operation of peaking generation assets generally by those with large vertically-integrated generation portfolios. These organisations have larger, geographically diverse and technologically different generators that provide for diversity benefits for larger portfolios. Single site intermittent generators have no diversity benefit or generally much small portfolios around which to absorb output fluctuations so they need to consider purchasing high levels of hedging products (or taking on more risk if they take the same level of hedging cover as a portfolio generator) in order to firm up the output from their single intermittent generation site.

Accordingly the simplest and less risky transaction for the intermittent generator at this stage of the market is to sell non-firm intermittent energy rather than taking out additional hedge for a period that is unlikely to match either the financing arrangements or off take agreement in order to firm up the output and sell that firm product into the wholesale market.

Source: Marsden Jacob analysis for the AEMC.

97 So, if wind buys a cap and sells a hedge that results in a lower return than for a dispatchable plant that does not need to buy the cap.

The Commission is interested in stakeholder views on how the contracting needs of participants (both those selling contracts, as well as those buying contracts) are adapting and changing in the NEM. Similar matters are being considered by the Commission in the *Five minute settlement* rule change request. Analysis undertaken for that rule change request will feed into this Review, particular those considerations in relation to operational and transitional matters. For example, in the *Five minute settlement* directions paper, the Commission set out some potential alternative risk management options in a world where there was five minute settlement. Some of the alternative options were: existing fast start generators changing the way in which they operate so that they can respond faster; fast generators and AEMO investing in more sophisticated forecasting methodologies and relying on these forecasts when making unit commitment decisions; new financial products could be developed that better match the physical capability of existing fast start generators.

Another source of contracts could be from new investments for example, energy storage and thermal plant technologies. For example, the Commission understands that the EnergyAustralia pumped hydro project in South Australia will consider innovative contracting, specifically for the purpose of firming up intermittent generation sources in that state.

In addition, there is a need to consider the *demand* for contracts. As more vertical integration is occurring, this could potentially be resulting in fewer contracts being demanded by participants, which could also contribute towards a lower amount of contracts being offered, and so higher prices.

Alternatively, large energy users may not feel that they have enough bargaining power in order to enter into contracts at efficient prices. A group of South Australia's biggest electricity users have recently banded together in a bid to negotiate favourable long-term electricity retail contracts. The "buying group" includes Whyalla steelworks owner Arrium, Hillgrove Resources, Rex Minerals, Seeley, SMR Automative, Thomas Foods and Central Irrigation Trust, which collectively use about 10 per cent of the state's electricity consumption.[98] This group recently received authorisation from theAustralian Competition and Consumer Commission (ACCC) to negotiate with generators.

**Question 7 Contract market**

**(a) Is generation and load becoming more capable of varying production and output in shorter timeframes, and if so, what will be the role of contracts? If generation and load could respond instantaneously to spot market signals, how would this change the contract market?**

**(b) The proportion of intermittent generation in the market is increasing. Caps and swaps have traditionally been sold by dispatchable generators**

98 See: http://www.abc.net.au/news/2017-02-21/sa-companies-push-for-long-term-electricity-contracts/8288710.

**which can turn on or off at will to 'back' their contractual obligations. How will the volume and type of contracts traded change as the generation mix evolves? Will this have implications for reliability?**

**(c) How significant is the demand-side in driving behaviour in the contract market?**

**(d) Over time, spot prices may become increasingly decoupled from domestic demand (as discussed in Box 6.3). More and more, spot prices may come to be driven by relatively unpredictable natural forces (like wind and sunshine), as well as by movements in international markets (like the demand for gas).[99] How will this affect the role of prices in supporting reliability through domestic investment and operation?**

It is important to recognise that many factors bear on the investment environment in the energy sector, and so affect investment decisions and so reliability in the NEM. Some of these factors are internal to the energy sector (for example, the contract market, which is a derivative market from wholesale spot prices), while others are external (for example, the existence or not of a certain, durable emissions policy). The efficacy of the contract market as an investment signal may be muted, or not effective if there are other external factors interfering with the market signals provided. These external factors, which could distort market signals, are discussed below.

## 6.3 Investment environment

### 6.3.1 Emissions policies

A particularly large external factor impacting on investment signals at the moment is market uncertainty created by the absence of an effective emissions policy, which is integrated with energy policy. As noted in chapter 3, in recent years numerous changes to government environmental policies has led to uncertainty, which in turn is having a detrimental impact on potential investment in new generation.

Market participants have noted that a lack of certainty regarding emissions policy is creating uncertainty in generation investment. Indeed, submissions to the Panel's *Reliability standard and settings review* noted that the lack of integration of climate change policies with energy policies has led to distortions to investment signals.[100] Stakeholders therefore advocate a national and integrated approach to climate change policy.

Any emission reduction policy mechanism that is introduced should consider the more enduring effects it may have on the energy market. In particular, how it affects not only the level of investment in physical capacity, but also how that investment in

99 **Although coal plants have historically been affected by international steaming black coal prices.**

100 Submissions to issues paper for *Reliability standards and settings review:* EnergyAustralia, p. 2; Snowy Hydro, p. 1.

generation is financed. Emission reduction policy mechanisms that incentivise investment in generation capacity without also incentivising the ongoing supply of firm-capacity hedge contracts, risk adversely distorting wholesale and retail market outcomes. They will inadvertently lessen the emerging competition from innovative new retail energy businesses, and place upward pressure on consumer prices.

Conversely, where an emissions reduction policy mechanism is effectively integrated and aligned with the design of the NEM, it is likely to lead to a higher degree of investment certainty in the energy market and more availability of firm-capacity contracts. This will likely reduce pressure on the wholesale electricity market, and can result in lower retail prices for consumers.

### 6.3.2 Government interventions

As noted in chapter 3, there have been an increasing number of government announcements for dispatchable generation capacity over the past year. This may also be creating uncertainty in the market, which was recognised by stakeholders in submissions to the Panel's *Reliability standard and settings review.* In particular, ENGIE noted that "the market and reliability settings cannot continue to deliver reliable system in the face of government interference at the state and federal level".[101]

### 6.3.3 Fuel prices

Another key input into investment decisions for generators is expectations of fuel prices. Recently, the large demand for gas from liquefied natural gas (LNG) facilities to meet their export commitments, combined with government-imposed moratoria and restrictions on the exploration and production of gas, are placing upward pressure on gas prices.

While gas-fired generation has lower upfront capital costs than some renewable developments, the higher (and expected to be increasing) gas prices are discouraging investment in gas plants.

In contrast, for investors wishing to invest in renewable sources, while the upfront capital costs may be higher, the marginal cost of their fuel (solar or wind) can be considered to be zero. Additionally, investors can also obtain revenue from certain policies that seek to incentivise investment in renewable energy. For example, under the LRET parties can finance their investment via revenue derived from generating certificates. This provides an additional source of revenue for these generators, compared with others.

Factors such as these may be further encouraging intermittent generation into the market, instead of dispatchable generation.

101 Engie, Submission to the Panel's *Reliability Standard and Settings Review*, 12 July 2017, accessed from http://www.aemc.gov.au/getattachment/b3bfbb82-fcf2-4422-8ed1-fb3a795e54c3/Engie.aspx.

### 6.3.4 Conclusion

The Commission is interesting in stakeholder views on how these external factors are influencing investment, retirement and operational decisions, and so reliability in the NEM.

> **Question 8 External factors**
>
> **What external factors (that is, not the contract, or spot price) are influencing investment, retirement and operational decisions in the NEM?**

## 6.4 Market information

While the investment side of reliability is left to the market, a key part of the operationalising the reliability standard is for AEMO to provide information to the market, as discussed in chapter 2. AEMO must continuously monitor levels of generation as generators retire from the market, and new generators take their place.

AEMO's ESOO assesses supply adequacy across the NEM over the next ten years, taking into account any significant developments. In the short- and medium- term, AEMO assesses supply adequacy through its Projected Assessments of System Adequacy (PASA) process. This involves collecting information and analysing if electricity supply can meet the reliability standard in the short-term (covering the period six days into the future, starting from the end of the trading day covered by the pre-dispatch schedule) and medium-term (a two-year outlook), and the very short-term, that is one day ahead via the pre-dispatch schedule. The focus of this section is on these mechanisms.

AEMO informs the market through these reports, as well as market notices, about the current and projected levels of available reserves. The purpose of these processes is to *inform* market participants of periods of low reserves, in order to elicit a market response. And, if a market response does not materialise, then as a consistent, transparent tool to determine whether intervention is required in an operational timescale to increase the available reserves when intervention is allowed under the NER. Longer-term forecasts are purely that (that is, forecasts) and should not be taken to represent actual outcomes.

There are then intervention mechanisms that can be used, enabling AEMO to take action if it believes the balance of electricity supply and demand will not meet the reliability standard. These are discussed in the next chapter.

Until 2016, AEMO also published the National Electricity Forecasting Report (NEFR), which has now been renamed the Electricity Forecasting Insights (EFI).[102] The Electricity Forecasting Insights provides electricity consumption and maximum and

102 A full list of all of AEMO's forecasting and planning information may be found here: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights.

minimum demand forecasts over a 20-year outlook period (to 2036–37) for the NEM regions. However, it is not a requirement under the NER itself.

### 6.4.1 Energy Adequacy Assessment Projection (EAAP)

The Energy Adequacy Assessment Projection is an information mechanism that provides the market with a two-year outlook on the effect of energy constraints in the NEM. Energy constraints refer to fuel shortages or constraints that limit the ability to use a generator, such as access to water for cooling or for hydro generation. The energy constraints are based on information provided by scheduled generators and include information regarding planned outages, power transfer capability of the NEM, and demand forecasts that are provided by jurisdictional planning bodies for the purposes of the ESOO.

Under rule 3.7C of the NER, AEMO is required to produce the Energy Adequacy Assessment Projection annually. The Energy Adequacy Assessment Projection Guidelines sets out trigger events for when additional Energy Adequacy Assessment Projection reporting would need to occur. NER clause 3.7C(k) states that AEMO must define variable parameters that are likely to have a material impact on the Energy Adequacy Assessment Projection, including:

- hydro storage including pump storage
- thermal generation fuel
- cooling water availability
- gas supply limitations.

Energy constraints are provided by scheduled generators via the Generator Energy Limitation Framework.[103] The Energy Adequacy Assessment Projection Guidelines state that limitations could be due to a number of causes including, but not limited to:[104]

- limitations on a primary energy source (that is, coal, gas or availability/allocation of water for hydro power generation)
- limitations on power station services (that is, cooling water, high cooling water temperatures, boiler feed water, etc.)
- environmental issues, such as emission limits, operation allowed only at specific times of the day/week, etc.

103 In accordance with NER Clause 3.7C(g).

104 See AEMO's EAAP Guidelines https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2016/EAAP/EAAP_Guidelines.pdf.

The Energy Adequacy Assessment Projection provides information to market participants on potential energy constraints. This information can lead to market responses that improve the use of constrained generation inputs, therefore contributing to the reliability of the national electricity system and potentially leading to more efficient prices.

### 6.4.2 Electricity Statement of Opportunities

The Electricity Statement of Opportunities is prepared annually by AEMO and provides a ten-year projection of the electricity demand and supply for both summer and winter maximum demand conditions. As mentioned above, it is a requirement under the NER.

The purpose of the Electricity Statement of Opportunities is to inform the market of forecast supply and demand conditions, and the likely timing of anticipated shortfalls of capacity to meet demand and, therefore, opportunities for investing in new generation or network capability. In particular, periods of low projected reserves in the report indicate likely periods of high prices and, therefore, are expected to encourage investment in additional capacity in the associated regions.

In June 2017, AEMO published the Energy Supply Outlook, an integrated assessment of gas and electricity supply adequacy for eastern and south-eastern Australia. In releasing the Energy Supply Outlook, AEMO noted that it looks specifically at the next two years and identifies what is required to maintain power system security in extreme summer conditions.[105] The June 2017 Energy Supply Outlook underpins AEMO's forecasts of whether each NEM region will meet the reliability standard over the next two years, based on the generation and storage expected to be available.[106]

AEMO also noted that it published the Energy Supply Outlook after reflecting on both the government and market response following the March release of the Gas Statement of Opportunities.[107] The Commission understands that AEMO intends to keep publishing the Electricity Statement of Opportunities by the end of August each year as required under the NER.

### 6.4.3 Projected assessment of system adequacy reports

AEMO publishes projected assessment of system adequacy (PASA) reports, namely, a short-term; and a medium-term, discussed below. AEMO also generates a pre-dispatch PASA, which provides forecasts for up to 40 hours ahead but this is not generally published. Instead, forecasts relating to one day ahead are published via the pre-dispatch schedule.

105 See: AEMO's media release https://www.aemo.com.au/Media-Centre/AEMO-Energy-Supply-Outlook.

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

107 Ibid.

### Short-term PASA

The short-term PASA is published every two hours, and provides detailed disclosure of short-term power system supply/demand balance prospects for six days following the next trading day. The information is provided for each half-hour within the report period.

### Medium-term PASA

The medium-term PASA is one of the main tools AEMO uses to assess expected electricity supply and demand in the next two years. The medium term PASA assesses the adequacy of expected electricity supply to meet demand across a two-year horizon through regular assessment of any projected failure to meet the reliability standard.

The medium-term PASA incorporates two separate functions:

- A high frequency three-hourly information service that gives a regional breakdown of the supply situation, including demand forecasts, network capacities and aggregate generating unit availabilities, over the two-year horizon, taking into account participant submissions on availability (not a NER requirement).
- A weekly assessment of system reliability, including provision of information on demand, supply and network conditions (NER clause 3.7.2).

In 2016, AEMO commenced a project to review the medium-term PASA. It noted that the previous medium-term PASA methodology was designed when there was negligible intermittent generation in the NEM, and the proportion of wind and solar generation was small. However, as detailed in chapter 3, over the years the NEM has evolved, and more intermittent generation has been installed. Therefore, AEMO considered there was an urgent need to reassess the medium-term PASA methodology to make sure that AEMO's projection of power system adequacy two years ahead remains accurate and relevant. Otherwise, there is a risk that stakeholders, or AEMO, may adversely react to, or make decisions about whether or not to intervene in the market, based on incorrect information.

In particular, AEMO engaged Ernst & Young to recommend improvements to the methodology. EY recommended that:[108]

- AEMO should implement the medium-term PASA reliability assessment using a probabilistic modelling approach to better capture the impact of stochastic inputs such as demand, generation outages or availability of intermittent generation. The reliability standard is probabilistic, and therefore it is appropriate to capture

108 EY's report is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Data/MMS/2016/EY-MTPASA-Final-Report-2016-11-23C.pdf.

the distribution of outcomes under a range of possible supply and demand conditions when determining the expected level of unserved energy.

- The modelling should be done at a half-hourly resolution.
- At least five reference traces for demand, solar and wind should be sampled for each demand scenario (10% Probability of Exceedance (POE) and 50% POE) to capture historically observed variations in intermittent generation availability and coincidence of demand between regions.
- 200 iterations[109] should be run for each reference year and demand case combination to capture the expected impact of unplanned generation outages. This equates to a total of 2,000 simulations per year.
- There should be a change from weekly to at least quarterly frequency for reliability assessment due to the intense computational requirements of the probabilistic modelling.
- The three-hourly supply-demand run should continue as it provides valuable information to help participants optimise their operations. Reporting aggregate medium-term PASA bids at a more granular level, would improve the service.

AEMO has recently completed the rules consultation procedure to amend the *Reliability Standard Implementation Guidelines,* to incorporate the recommended changes to the medium-term PASA. AEMO incorporated most, but not all, of the changes recommended by Ernst & Young following consultation.[110]

### Use of the PASAs

Market participants use this information to make decisions about what capacity to offer into the wholesale market, when to consume electricity,[111] as well as the scheduling of planned outages (generation, load and transmission) in the NEM. AEMO uses this information as a trigger to intervene in the market to address forecast reserve shortfalls (see chapter 7).[112]

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109 While called iterations these are not actually 'iterations' as they do not iterate to a solution. Rather they are different simulations that are averaged to give an expected outcome.

110 For example, AEMO noted in its final determination that will continue to run medium-term PASA on a weekly basis. It also noted that it will seek a rule change to remove consideration of network constraints when reporting energy constrained and unconstrained capacity due to analytical challenges. See AEMO, *Reliability Standard Implementation Guidelines, Final report and determination*, 15 August 2017, accessed from https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2017/MTPASA/RSIG-Final-Report.pdf.

111 Although most end consumers do not take this into consideration.

112 The identification of low reserves in the short-term PASA will be one of the variables used by AEMO within the *Peak Electricity Demand – Gas Supply Guarantee* to trigger an assessment conference to decide on an industry-facilitated response.

With regards to planned generation outages, i.e. those typically due to generation maintenance, the Commission is interested in stakeholder views on whether the current level of reporting associated with this is sufficiently transparent, particularly in terms of providing signals to the market. The published information of planned generation outages is not as detailed as what is provided to AEMO, due to commercial and confidentiality reasons.

### 6.4.4 Pre-dispatch schedule

The pre-dispatch process calculates projected market outcomes on a trading interval basis from the next trading interval to the final trading interval of the day for which all dispatch bids and offers have been received. The objective of the pre-dispatch process is to provide market participants with projections of spot prices and expected dispatch schedules to assist them to determine when to commit their generating units. As generators are required to self-commit, pre-dispatch forecasts are essential for generators to determine whether to be online.

NEM customers also rely on pre-dispatch forecasts to manage their pricing risk. Pre-dispatch forecasts assist customers to determine whether they need to consider forward contracting or to prepare for demand-side response. Therefore, reliable and accurate information is key to determining meaningful pre-dispatch forecasts and allowing competitive demand and supply side responses. The outcomes of the pre-dispatch process are published in the pre-dispatch schedule.

Outcomes include 30-minute pre-dispatch (forecast) data by region to the end of the next market day, which is updated half hourly and 5-minute pre-dispatch (forecast) data by region, showing short-term price and demand forecasts looking out one hour ahead.[113]

### 6.4.5 Low reserve conditions

AEMO uses the various PASA mechanisms, described above, to assess when a low reserve condition (LRC) occurs. A low reserve condition (LRC) is defined under clause 4.8.4(a) of the NER as being "when AEMO considers that the balance of generation capacity and demand for the period being assessed does not meet the reliability standard as assessed in accordance with the *Reliability Standard Implementation Guidelines*."

Until recently, AEMO declared a LRC if the medium-term PASA capacity reserves are projected to be inadequate on any given day. AEMO could also apply probabilistic studies such as the EAAP to confirm the medium-term PASA results.[114]However,

113 See for more information https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Pre-dispatch.

114 AEMO, *Reliability Standard Implementation Guidelines*, October 2016, accessed from https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2016/EAAP/Reliability-Standard-Implementation-Guidelines.pdf.

under the new *Reliability Standard Implementation Guidelines,* to apply from 26 October 2017, the medium-term PASA will use a probabilistic methodology to assess LRCs. An LRC will be identified if the expected annual unserved energy exceeds the maximum level specified by the reliability standard.[115]

AEMO's responses to a LRC include notifications to the market via reports, or by direct action in the form of directions, instructions or use of the RERT (discussed in chapter 7).

### 6.4.6 Lack of reserve

One of the outcomes of the short-term PASA, as mentioned above, is a quantification of the ability of a region to meet its demand following a credible contingency. There are three lack of reserve (LOR) levels that relate to the severity of the system conditions in terms of the number of contingencies that can occur before involuntary load shedding occurs, defined under clause 4.8.4 of the NER:

- Lack of reserve level 1 (LOR1) - this is considered to apply if there is insufficient reserves to cover two successive credible contingencies, such as the loss of the two largest generating units.

- Lack of reserve level 2 (LOR2) - this is considered to apply if there is insufficient reserves to cover a credible contingency, such as the loss of the largest generating unit.

- Lack of reserve level 3 (LOR3) - this is considered to apply when there is insufficient supply to meet demand. An LOR3 condition would represent load shedding.

AEMO uses LOR declarations to communicate short-term risk to the industry, government and consumers. LOR declarations are notified to the market under clause 4.8.5 of the NER. The effect of issuing a market notice is to encourage any spare supply to be bid into the market. If an LOR is not resolved by a market response, AEMO can then trigger intervention mechanisms (discussed in chapter 7).[116]

Similar to the medium-term PASA, AEMO considers that the existing LOR framework is progressively becoming less relevant in the changing power system, where significant rapid deteriorations in short-term power system conditions now frequently occur due to non-contingency based variations. Accordingly, on 1 August 2017, AEMO submitted a rule change request to the Commission seeking to modify this framework

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115 AEMO, *Reliability Standard Implementation Guidelines - Effective 26 October 2017*, 15 August 2017, accessed from https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2017/MTPASA/Reliability-Standard-Implementation-Guidelines---MT-PASA-Final.pdf.

116 Operationally, AEMO uses the LOR2 condition as a short-term intervention trigger, in particular, to trigger the short-notice RERT.

to make it fit-for-purpose in the changing environment, which was discussed in section 5.2.[117]

The Commission is considering issues associated with the LOR framework through a separate rule change request process.[118] A consultation paper for this rule change request was published alongside this Issues Paper on 22 August 2017. While this rule change request is being considered through a separate process, it is worth noting that to the extent this Review considers broader, more holistic changes to the reliability frameworks, the LOR framework will also need to be considered in that context.

### 6.4.7 Conclusion

There are a number of different reports and tools that AEMO uses to notify market participants in relation to reliability. The Commission is interested in stakeholder views on the effectiveness of these reports given the drivers of change. For example, there has been a recognition that the increasing penetration of intermittent generation, along with the continued retirement of thermal generation, is likely to be having an impact on the accuracy of AEMO's forecasts. AEMO has already been assessing ways to improve its forecasts for example, introducing a new medium-term PASA process. However, a more holistic review of these reports may be warranted.

In addition, the various reports all interact with other in terms of the provision of forecasts and information to the market. As summarised in Table 6.1, AEMO often uses the same underlying assumptions and variables in each report. For example, National Electricity Forecasting Report (now Electricity Forecasting Insights) serves as an input to demand forecasts in more than one report. Practically, this means that when one report is updated, another may become out of date. As a result, the June 2017 Electricity Supply Outlook publication effectively updated the November 2016 EAAP due to new information and data that became available between the two updates.

117 See: http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions.

118 See: http://www.aemc.gov.au/Rule-Changes/Declaration-of-lack-of-reserve-conditions.

**Table 6.1 Assumptions and variables used in market information reports**

| | Electricity Statement of Opportunities | Energy Adequacy Assessment Projection | Medium-term PASA | Short-term-PASA |
|---|---|---|---|---|
| Time frame/frequency of publication | 10-year/annually | Two-year/ annually | Two-year/ weekly | Six-day/two hourly |
| Assumption for potential breach of reliability standard | Directly assess USE expectations based on probabilistic modelling | Directly assess USE expectations based on probabilistic modelling | Directly assess USE expectations based on probabilistic modelling | Is any region in LOR2 or LOR3? |
| Forecast demand | Based on National Electricity Forecasting Report (now Electricity Forecasting Insights) and historical weather patterns | Based on National Electricity Forecasting Report (now Electricity Forecasting Insights) and historical weather patterns | Based on National Electricity Forecasting Report (now Electricity Forecasting Insights) and historical weather patterns | 50% POE half-hour demand based on expected weather patterns |
| Intermittent generation | Based on historic weather patterns | Based on historic weather patterns | Based on historic weather patterns | Based on AWEFS and ASEFS [119] |
| Scheduled generation capacity and outages | Annual survey | Medium-term PASA offers | Medium-term PASA offers | Available capacity – PASA availability |
| Energy constraints | Based on historical observations | Provided through Generator Energy Limitation Framework (GELF) | Weekly energy constraints submitted by participants. Monthly inflow of water assumed for hydro plants based on historical observations. GELF may also be used. | Daily energy constraints considered. |

Source: adapted from AEMO's *Reliability Standard Implementation Guidelines*. The information in the table reflects the recent changes to the guidelines which will come into effect in October 2017.

119 Australian Wind Energy Forecasting Systems and Australian Solar Energy Forecasting Systems respectively.

Steps have been taken to harmonise the information used in the three reports. For example, in proposing changes to the medium-term PASA process, AEMO has noted that a probabilistic approach to medium-term PASA modelling approach would provide more consistency of information between medium-term PASA, Energy Adequacy Assessment Projection and Electricity Statement of Opportunities.[120] As an example, generator energy limitation framework which is used to provide energy constraints information in the Energy Adequacy Assessment Projection may also be used for the medium-term PASA process from November 2017.

**Question 9 Efficacy and efficiency of information provision**

**(a) What is the potential for the reports (Energy Adequacy Assessment Projection, Electricity Statement of Opportunities and PASA) to be streamlined or made more efficient given existing interactions?**

**(b) Is the information provided by the reports adequate given that it has the purpose of information provision to the market for reliability and investment purposes?**

**(c) In particular, is the information around planned generation maintenance and outages adequate?**

**(d) What other information do stakeholders rely on?**

120 AEMO, *Reliability Standard Implementation Guidelines - Effective 26 October 2017*, 15 August 2017, accessed from https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2017/MTPASA/Reliability-Standard-Implementation-Guidelines---MT-PASA-Final.pdf.

# 7 Intervention aspects of the reliability framework

This chapter discusses the intervention aspects of the reliability frameworks in the NEM and raises questions associated with this part of the framework that the Commission would welcome feedback on from stakeholders. In particular:

- section 7.1 discusses the role of reliability interventions in the NEM in the context of a market-based approach to achieve reliability
- section 7.2 discusses the processes and tools that AEMO uses to trigger interventions
- section 7.3 discusses the RERT and reliability demand response in the NEM
- section 7.4 discusses directions and clause 4.8.9 instructions.

## 7.1 Role of AEMO's reliability interventions

Section 49 of the National Electricity Law sets out AEMO's statutory functions, including (amongst others) "to maintain and improve power system security. Section 49A then states that AEMO has the power to do all things necessary or convenient for or in connection with its conferred responsibilities. Therefore, AEMO will manage the power system to maintain it in a secure operating state. A reliable power system is one which is also in a secure operating state and AEMO manages the power system as such.

As discussed in chapter 2, the current reliability framework is largely market-based, but does have some elements of intervention intrinsic in it.[121] There are intervention mechanisms in the NER, which enable AEMO to take action if it believes that operationally, the balance of electricity supply and demand will not meet the reliability standard, or there will not be sufficient reserves:

- AEMO can activate the RERT mechanism, which allows AEMO to contract for (or ‘lock in’) electricity reserves ahead of a period where it projects a shortage[122]
- in addition, if there is a lack of response from the market in relation to the price and information signals discussed in chapter 6, and there is a risk to the secure or reliable operation of the power system, AEMO can use directions or instructions under NER clause 4.8.9 to:
  - Direct a generator to increase its output, but only if this is possible and can be done safely. To be effective, the generator must have enough time to

121 for example, the reliability settings as discussed in chapter 6.

122 Currently under clause 3.20.3(d) of the NER, AEMO must not enter into, or renegotiate, a contract more than 9 months prior to the date that it reasonably expects the reserve under that contract to be required.

'ramp up'. If the generating unit is not already generating, it can take time for it to connect to the network and begin to ramp up.

— Direct a large energy user, such as an aluminium smelter, to temporarily disconnect its load or reduce demand.[123] This only applies to large users who are registered participants.

If there continues to be a shortfall in supply, AEMO may use involuntary load shedding as a last resort to avoid the risk of a wider system blackout or damage to generator or networks. Network businesses shed this load on instruction from AEMO following schedules provided by the relevant state government.

These various intervention mechanisms (RERT, instructions and directions) provide a "safety net" in the event that there is insufficient generation capacity to meet demand. They provide the ability for AEMO to attempt to reduce the level of any electricity load shedding of customers.

Intervention mechanisms help to address the potential impact of market uncertainty on power system reliability, in the event that market responses to an uncertainty-induced projected reserve shortfall may not fully address that projected shortfall. Therefore, in times where there is a high degree of uncertainty that will impact on the effectiveness of price signals in markets, intervention mechanisms can help deal with these market failures, by providing a certain or guaranteed amount of capacity in order to provide a reliable supply of generation.

However, intervention mechanisms may also have distortionary impacts. The existing intervention mechanisms were designed to minimise distortions, but the presence of such mechanisms can in and of themselves, deter market responses. For example, the RERT could be considered to be a parallel market for reserves, potentially constraining the ability of market-based reserve contracts such as demand response. In addition, intervention mechanisms are typically more costly for consumers, since there are costs associated with certainty, as noted in chapter 4.

While the Commission has examined the existing intervention mechanisms on an individual basis in the past (mainly to determine the extent of their sunset clauses), it is now considering these mechanisms in the context of the broader reliability framework and drivers of change within the NEM.

123 Where this a sensitive load, this requires coordination with the jurisdictional system security coordinator.

**Question 10 Role of interventions**

**(a) What is the role of intervention mechanisms in the reliability frameworks? Does this role change in times of uncertainty?**

**(b) To what extent do stakeholders consider that intervention mechanisms inhibit market-based responses, and create distortions within the framework?**

**(c) To what extent are interventions preferable to load shedding?**

## 7.2 Triggers for intervention

As discussed in chapter 6, AEMO undertakes a number of planning and forecasting processes that seek to assess whether the power system meets, and is projected to meet, the reliability standard.

If a shortfall of reserves is projected, AEMO uses a variety of ways to inform the market to try and elicit a market response, for example, through market information reports and by issuing low reserve and lack of reserve condition notices. AEMO may also use informal methods such as phoning generators to get a response. If these fail to elicit a market response, then AEMO can exercise its intervention powers, at its discretion.

The NER specify high-level conditions under which AEMO can intervene for reliability purposes: if there has been a failure of the market to deliver sufficient reserves or if the secure and safe operation of the system is under threat. However, operationally, the NER provides AEMO with discretion when triggering interventions. In doing so, however, AEMO typically follows two principles:

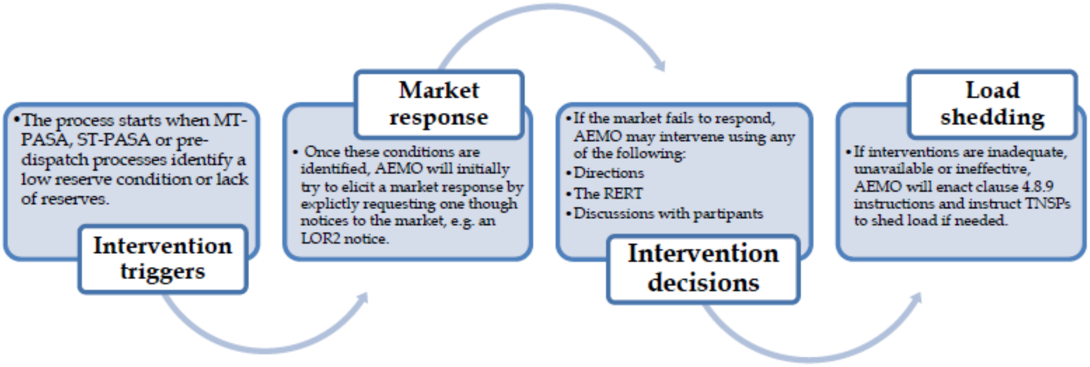
- actions taken by AEMO should have the least distortionary effect on the operation of the market
- actions taken should aim to maximise the effectiveness of reserve contracts at the least cost to consumers.

The NER also require AEMO to minimise the market impact of its intervention in terms of the number of affected participants and changes to interconnector flows,[124] which it also considers when deciding which mechanism to use.

Figure 7.1 summarises the chain of events that AEMO would typically go through when triggering an intervention. However, as each intervention is different; the intervention method that it uses and the decisions made vary depending on the expected effectiveness of the possible methods under the circumstances of the day, for example, AEMO may use a direction and then use the RERT in one instance. In another, it may use the RERT first then a direction, or it may only use one of the mechanisms available to it.

124 NER clause 3.8.1(b)(11).

**Figure 7.1 AEMO's reliability intervention process**




| Question 11 Triggers for intervention |
| --- |
| **Do stakeholders consider that there is sufficient transparency about the existing triggers for intervention?** |

## 7.3 The RERT

### 7.3.1 History of the RERT

The RERT, or some form of mechanism for the market operator to contract for reserves, has been a feature of the NEM since its commencement in December 1998. At the time, such a mechanism were deemed to be necessary due to uncertainty around how the market would respond to price signals, but the intention was that it would be removed after a period of time.

Over time, periodic reviews of the reserve trader provisions have led to various amendments, including postponing its expiry date, as well as changes to its scope and operation. The RERT was developed as part of the Panel's 2007 *Comprehensive Reliability Review*. The RERT was incorporated into the NER in June 2008, and replaced the reserve trader provisions. As discussed, while the RERT was originally designed with a sunset clause, in June 2016, the Commission extended it indefinitely.[125] In its decision, the Commission noted that ongoing uncertainty raised the likelihood that future electricity demand may not be adequately met, and also raised the likelihood that the ensuing market responses to address these projected shortfalls may be insufficient.

In particular, the Commission noted that recent uncertainty has been associated with:

- the extent and impact of changes in the generation mix associated with an increasing penetration of renewables in the NEM. The change in the generation

125 AEMC, *Extension of the Reliability and Emergency Reserve Trader*, Final Determination, 23 June 2016.

mix, in particular the exit of conventional generation has occurred at a rapid pace, especially in South Australia

- uncertainty associated with the implementation, uptake, and impact of demand-side policies in the NEM
- the mechanisms needed to achieve Australia's post-2020 carbon reduction targets, and the impact of these targets and mechanisms on generation capacity.

The Commission was of the view that the RERT, along with the other reliability intervention mechanisms, could help AEMO's management of power system reliability in light of this uncertainty. As noted in chapter 2, while the reliability standard is expected to be met over the next two years based on current forecasts of generation and storage, AEMO has noted that there is still a risk of electricity supply falling short of demand, especially in extreme conditions.[126]

When the Commission extended the use of the RERT indefinitely it noted that it considered that the RERT is a more efficient intervention mechanism than reliability directions or clause 4.8.9 instructions. Load curtailment under the RERT is on a contractual basis, unlike the other two mechanisms, and so it can be considered more efficient since it will take into account a particular supplier's value of energy.

The Commission also noted that the while the RERT may create potential for market distortions, these distortions appear minimal. It also noted that making the RERT a permanent feature of the market will provide AEMO and other market participants the opportunity to consider changes that may improve the operation of the RERT. This Review provides the perfect opportunity for market participants to consider such changes.

### 7.3.2 Operation of the RERT

The RERT is a mechanism that allows AEMO to contract for additional capacity (reserves) not otherwise available in the market for a period ahead of when AEMO projects there to be reserve shortfalls. A projected reserve shortfall is where the amount of generation capacity is projected to be below the level consistent with the reliability standard. This means that there is an increased probability of a shortfall of generation causing some consumer load to be shed.

Under the current NER, AEMO can contract for reserves up to nine months ahead of a projected shortfall in reserves. However, from 1 November 2017, this will reduce to ten weeks, following the recent Commission determination, which made this change to allow greater opportunity for a market response to address that shortfall.[127] AEMO is also able to dispatch these additional reserves to manage power system reliability and, where practicable, security.

126 AEMO, *Energy Supply Outlook*, June 2017, p. 3.

127 AEMC, *Extension of the Reliability and Emergency Reserve Trader*, Final Determination, 23 June 2016.

The NER require the Reliability Panel to develop and publish guidelines (the RERT guidelines),[128] which provide guidance for AEMO in its operation of the RERT. As set out in the NER, the RERT guidelines include, amongst other things, the process AEMO should follow when contracting for reserves under the RERT, as well as the scope and principles to be employed by AEMO when procuring reserve capacity.[129] Specifically, NER clause 8.8.1(4) states that while AEMO has power to enter into contracts for the provision of reserves, one of the functions of the Reliability Panel is to determine policies and guidelines governing AEMO's exercise of that power.

The NER also require AEMO to develop procedures (the RERT procedures)[130] that detail how AEMO intends to exercise the RERT, including the process for selecting participants for the RERT panel. In exercising the RERT, AEMO must take into account the RERT principles, and in doing so, must also have regard to the RERT guidelines. The RERT principles are set out in NER clause 3.20.2(b) and state that when exercising the RERT:

- actions taken should be those which AEMO reasonably expects, acting reasonably, to have the least distortionary effect on the operation of the market
- actions taken should aim to maximise the effectiveness of reserve contracts at the least cost to end-use consumers of electricity.

There are three types of RERT based on how much time AEMO has prior to the shortfalls occurring as specified in the Panel's guidelines:

- long-notice RERT - at least ten weeks' (up to nine months' notice) notice of a projected reserve shortfall (after 1 November 2017 the long-notice RERT will cease to exist)
- medium-notice RERT - between ten and one week's notice of a projected reserve shortfall
- short-notice RERT - between seven days' and three hours' notice of a projected reserve shortfall.

Under the RERT guidelines, AEMO may establish a panel of entities, a RERT panel, that can tender for, and enter into, reserve contracts for medium-notice and short-notice situations. Once reserve providers are members of the RERT panel, reserve contracts can be finalised more quickly than through a full tender process.

AEMO procures additional capacity that may not otherwise be available to the market according to the following processes:

128 NER clause 3.20.8.

129 The Reliability and Emergency Reserve Trade (RERT) Guidelines may be accessed here http://www.aemc.gov.au/getattachment/98a21db3-9e02-4e7e-9626-8973f0f45e5c/Reliability-and-Emergency-Reserve-Trader-(RERT)-Gu.aspx.

130 NER clause 3.20.7.

- parties who have non-market generation capacity make themselves known to AEMO and declare what price those parties wish to be paid to use that capacity
- individuals or groups of consumers declare what remuneration they would seek to reduce their demand in excess of the saving in energy cost.

RERT contracts are highly bespoke and the compensation structure varies depending on each individual contract. However, they generally contain the following types of payments:[131]

- a pre-activation payment (for unscheduled reserves only)
- a usage payment ($/MWh) when instructed to dispatch
- an availability payment under the medium-notice RERT once the contract is enacted (that is, for a maximum of 10 weeks)[132]
- an optional early termination payment for the medium-notice and long-notice RERT in case AEMO cancels the contract, for example, if forecast shortfalls are revised.

The costs of the RERT are incurred by market customers in the region where reserves are required.

**Question 12 Efficiency of the RERT**

**Do stakeholders consider that the RERT is still a relevant mechanism to ensure a reliable supply of energy in the NEM?**

### 7.3.3 Preliminary views on ways to improve the operation of the RERT

As noted, AEMO and ARENA are currently piloting a demand response initiative this summer to manage electricity supply during extreme peaks, as an extension of the existing RERT. Through this process the Commission understands that AEMO has identified a number of shortcomings with the current RERT framework, namely:

- Procurement trigger: RERT cannot be triggered unless a specific, quantified reserve shortfall is forecast. RERT is unable to be accessed for unanticipated shortfalls.
- Lead time for procurement: AEMO can only enter into reserve contracts up to nine months prior to the reserve being required (and only up 10 weeks from 1

131 Based on information provided at a RERT information session on 20 June 2017 and AEMO, *RERT: Reliability and Emergency Reserve Trader*, June 2017, accessed from https://www.aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/2017/RERT-Information.pdf.

132 There is no payment for being on the panel.

November 2017). The very short lead times limits the scope of RERT providers and potentially leads to higher prices.

- Efficient outcomes and price discovery: The RERT involves direct contracting, with a range of bespoke products driven by bilateral negotiations results in limited price discovery. To date, the RERT has incentivised little demand-side participation according to AEMO.

**Procurement trigger**

AEMO uses the short-notice RERT to minimise unserved energy in near real time. The medium-notice and long-notice RERT is to be used to manage power system reliability in the event that market responses (as described in chapter 6) to projected reserve shortfalls are, or are likely to be, insufficient to meet the reliability standard. When this was designed it was considered to be consistent with a market-driven framework for reliability, since, the existence of a standing reserve mechanism would lead to distortions. In other words, participants may not respond to price signals, even if that would be efficient for them to do so, because they are awaiting an even higher pay off under a separate reserve mechanism. Further, restricting the use of the RERT to anticipated shortfalls minimises the costs associated with the use of the RERT for consumers.

The RERT guidelines specify what AEMO may take into account when it is determining whether to enter into contracts for the RERT (procurement triggers) and when it is considering whether to dispatch reserves (dispatch triggers):

- To procure the long-notice and medium-notice RERT, AEMO may take into account the outcomes of medium-term PASA, Energy Adequacy Assessment Projections and any other information it thinks is necessary ,for example, confidential information received from a generator warning of a potential reduction in capacity.

- For the short-notice RERT, AEMO may take into account the outcomes of the short-term PASA and pre-dispatch process and any other information it thinks is necessary.[133]

- Operationally, AEMO will seek to procure the RERT once one of these processes has identified a potential shortfall.

- Once RERT has been procured, the dispatch or activation trigger is generally an LOR2 forecast within the short-term PASA or pre-dispatch process, although AEMO may wait until an LOR3 occurs in the case of fast activation reserves.[134]

Since the RERT is procured only when a potential shortfall has been identified through one of the processes mentioned above, it cannot be used for unexpected shortfalls,

133 RERT can also be triggered for system security.

134 Although there would have been a pre-activation notice given to reserve providers once an LOR2 is identified.

which AEMO considers to potentially be problematic. Unanticipated shortfalls, particularly a rapid deterioration in reserves, have become more frequent.[135] The Commission understands that this view has also been reinforced by some stakeholders, who also consider that the RERT may no longer be fit for purpose in an era of unpredictable shortfalls.

It is worth noting that AEMO has submitted a rule change request to the AEMC that would change its declaration of LORs to a more probabilistic process. Since the LOR2 declaration is a trigger for the use of the RERT, this may, to some extent, address these concerns.

**Question 13 RERT procurement trigger**

**(a) To what extent do stakeholders consider that the fact that AEMO can only trigger the RERT for anticipated shortfalls is still appropriate?**

**(b) Is the procurement trigger still appropriate in a world where shortfalls are less predictable, and there is increased demand-side participation?**

**Lead time for procurement**

The short lead times, raised as an issue by AEMO, are also by design as they mitigate the market distortions created by the RERT - procuring reserves too far in advance of a projected shortfall may result in market distortions on both the supply side and demand side. This was one of the justifications of the Commission when removing the long-notice RERT. Reducing the timeframes in which AEMO may contract for reserves will minimise potential market distortions of the RERT and have the following benefits:[136]

- market participants will have greater time and opportunity to respond to a projected shortfall before AEMO enters into a RERT contract
- the likelihood that AEMO may crowd out potential market based arrangements would be reduced, for example, retailers could engage with their customers to reduce load
- AEMO's decisions on their potential use of the RERT could be made closer to real time, using more up-to-date information. This would reduce the likelihood that reserve contracts are entered into, but not dispatched.

In assessing market distortions in particular, the Commission noted that, these distortions relate to constraining the ability of market-based reserve contracts, for example, in demand response. The Commission understands that retailers typically approach their customers for the purposes of reserve procurement, a few weeks prior to a projected reserve shortfall. There is a risk that, by this stage, the customer’s reserve is already contracted to AEMO via the RERT. Consequently, the RERT could create a

135 See AEMO's rule change request discussed in Chapter 6.

136 AEMC, *Extension of the Reliability and Emergency Reserve Trader*, Final Determination, 23 June 2016.

parallel market for reserves, and represent a barrier to market responses (including demand response) to projected reserve shortfalls. Reducing the lead time would go some way in addressing that.

There was broad support for the Commission to reduce the RERT procurement lead time and AEMO did not object to the shortening of the lead time for procurement during that rule change process.[137] However, the Commission understands that in given the current environment, stakeholder views on reliability and, in particular, the long-notice RERT may have changed since the rule was made and that there may be interest in retaining the long-notice RERT.

**Question 14 RERT lead time**

**(a) To what extent do stakeholders consider that the lead times for the RERT constrain the ability of market-based reserve contracts being realised?**

**(b) What are stakeholders' views on the need for the long-notice RERT?**

**(c) Does the long-notice RERT have the potential to limit a market response?**

**Price discovery**

Each type of RERT is procured differently:

- For the long-notice RERT, it is an open tender process.
- With the medium-notice RERT, AEMO can either tender openly or seek offers from the RERT panel.
- For the short-notice RERT, AEMO seeks quotes from the RERT panel.

The RERT panel consists of entities that have negotiated and agreed certain technical and legal requirements in advance with AEMO, therefore reducing the length of time that might otherwise occur in negotiating reserve contracts under a full tender process. Once reserve providers are members of the RERT panel, reserve contracts can therefore be finalised more quickly than through a full tender process.

Despite the efforts made to address some of these concerns by the introduction of the RERT panel, the Commission understands that AEMO considers that the RERT is still bespoke in nature and tends to be driven and procured through complex and lengthy bilateral negotiations. As a result of the customised nature of the RERT, price discovery of reserve products is limited. As discussed below, there is currently a pilot program being trialled which offers two reliability reserve products only, rather than bespoke

137 AEMO, Submission to the AEMC's *Extension of the Reliability and Emergency Reserve Trader* rule change, http://www.aemc.gov.au/getattachment/204c3739-ea45-4ea5-a871-86572cf42fc9/Australian-Energy-Market-Operator.aspx.

products.[138] ARENA has stated that one of the aims of the program is to allow better price discovery. The outcomes of the trial are yet to be available.

**Question 15 Price discovery**

**To what extent do stakeholders consider that the price discovery process of the RERT could be improved?**

**Reliability demand response**

AEMO can currently enter into contracts under the RERT with both demand-side and supply-side participants. Therefore, the Commission does not consider that there are any regulatory barriers to demand response being used for reserves in the NEM, as discussed further in appendix B. However, to date, there has been little interest from demand respond providers in participating in the RERT.

Indeed, this is the purpose of the ARENA-AEMO trial, as detailed in Box 7.1 below. This trial supplements the existing RERT and seeks to make this a more attractive mechanism for demand response providers. The Commission is particularly interested in this trial, and has been working closely with AEMO and ARENA on its development.

**Box 7.1 ARENA-AEMO demand response trial**

In May 2017, ARENA and AEMO announced they were partnering to run a pilot program to incentivise demand response for reliability purposes. The three-year pilot program aims to provide 160 MW of reserve capacity which AEMO can call upon when reserves are low to prevent load shedding.

Under the program, energy users or their service providers (for example, aggregators and energy retailers) who are successful with their funding application will receive a grant from ARENA as an incentive, or availability payment, to provide standby capacity during emergency or reserve shortfall events.

The compensation structure of ARENA's incentive has the following features: an up-front payment, a payment when the contract is signed, a payment on completion of initial testing, a performance amount linked to testing results and activation performance and a knowledge sharing amount. The last two components have penalties associated if performance is not achieved.

Successful participants will also sit on the short-notice RERT panel and will receive payment from AEMO via the panel if they are called upon to dispatch

138 See https://arena.gov.au/funding/programs/advancing-renewables-program/demandresponse/.

reserves, at a fixed, pre-agreed $/MWh rate. The pilot will be trialled in Victoria, South Australia and New South Wales,[139] with demand response capacity expected to be made available from 1 December 2017.

For demand response to qualify for the trial, it must meet the following criteria:[140]

- aggregation of one or more customer loads across multiple sites within a NEM region
- distribution system-connected, unscheduled customer load
- metered by a type 1-4 meter or a Victorian AMI meter.

The funding round closed on 17 July 2017 and preliminary information suggests that about 700MW of potential demand response capacity could be made available by 1 December 2017 and almost 2000MW of capacity by the end of 2018. ARENA noted that demand response capacity is evenly spread among industrial, commercial and residential users, with a diversity of technologies, including industrial load curtailment and batteries.[141]

The program features two products, one offering a 60-minute notification period and a faster product, a 10-minute notification period until load has to be curtailed via demand response. Successful participants will need to be available for a four-hour window between 10am and 10pm on business days.

The program is aimed at "reliability demand response", that is demand response to provide for reserves for reliability purposes and is intended to serve as a proof of concept that AEMO will then progress as a RERT rule change to the Commission in 2018. ARENA also intends for this project to be a stepping stone for innovation in demand-side participation in the NEM beyond reliability.

Source: https://arena.gov.au/funding/programs/advancing-renewables-program/demandresponse/

In addition to the 160MW of reserves being procured via the short-notice RERT through the ARENA trial, AEMO is also seeking about 600 MW of reserves for the 2017-18 summer via the long-notice RERT. This will be the last time that the long-notice RERT is available under the current NER.

139 The trial was initially limited to Victoria and South Australia. However, following an additional funding announcement from the NSW Government, ARENA and AEMO extended the trial to New South Wales.

140 ARENA, *Demand response competitive round - information session*, accessed from https://arena.gov.au/assets/2017/06/ARENA-DR-Funding-Round_Info-session_PUBLIC.pdf.

141 This was highlighted in an email to ARENA's stakeholders and has also been reported in the media. See for example http://www.abc.net.au/news/2017-07-13/household-electricity-trading-app-may-be-funded-by-government/8707010.

The Commission is interested in any findings from the trial on why demand response has historically not been interested in participating in the RERT. One such reason may be the fact that the current RERT does not pay interested participants an availability payment (that is, being paid for capacity to be available even when the RERT is not being used).[142] Or, some participants may not have had the right equipment in order to meet the technical standards associated with the RERT, for example, appropriate metering. The ARENA funding could help to enable more participants to be "RERT-ready", so increasing the potential for demand response providers to participate in this process in the future.

**Question 16 Demand response for reliability purpose**

**(a) What are the reasons why most demand response providers have not participated in the RERT to date?**

**(b) What findings can be taken from the ARENA-AEMO trial in terms of how demand response could be better incorporated into the RERT?**

The Commission understands that following the use of the mechanism for the 2017-18 summer, it is likely that AEMO will submit a rule change request to the Commission in order to incorporate the findings of this into the NER. It is worth noting, as AEMO and the Finkel Panel have, that similar demand response programs are commonly used in other countries to address reserve issues. One such example is the emergency response service in the United States at the Electricity Reliability Council of Texas (ERCOT), which is discussed in Box 7.2. The Commission notes that caution should be taken in drawing comparisons to other markets. There is not one particular approach that can be considered as 'standard'. Regulatory frameworks are rooted in local circumstances and regulatory traditions.

**Box 7.2 ERCOT's emergency response service**

ERCOT introduced an emergency product called the Emergency Interruptible Load Service (EILS), which could be deployed in an emergency prior to shedding firm load, following an event in 2006 where it was forced to shed load for the first time since the market opened.

Under the EILS, in the event of an emergency, demand response resources could be called upon by ERCOT to curtail within 10 minutes. Participants could choose to be available during one of three business day time periods or during non-business days.

In 2012, the program was expanded to allow participation by distributed energy resources (DER) and the program was renamed the Emergency Response Service (ERS). ERCOT has made several changes to the program since, including

142 Bloomberg New Energy Finance study, *Demand Response in Australia: An Untapped Resource*, 24 May 2017.

introducing a 30-minute curtailment product.

The ERS's procurement mechanism involves generating a demand curve based on an annual expenditure limit of US $50 million. The total available funds are distributed across three annual auctions according to an assessment of the relative risk of an emergency event occurring in each of these three periods.

Participants of the EILS program, and its successor, the ERS, program are paid for their availability to be curtailed in the event of an emergency. This availability payment is similar to the payment received by loads participating in capacity market demand response programs. The ERS includes several availability periods (not just in summer) in which participants can register. In each one, resources can be activated in response to generation and transmission outages or extreme weather events.

ERCOT's ERS introduces a type of capacity mechanism for demand response reliability reserves in an energy-only market through an availability payment. The ARENA-AEMO trial follows a similar framework. For example, the ARENA-AEMO trial also features an availability payment and a 10-minute curtailment product. However, participants of the ERS do not receive further payments when load is curtailed while under the demand response trial, they would through the short-notice RERT panel usage payment.[143]

Source: Brattle Group, *International review of demand response mechanisms report* and ERCOT.

One of the Finkel Panel's recommendations was the assessment of the need for a "strategic reserve"[144] to act as a safety net in exceptional circumstances as an enhancement or replacement to the existing reliability and emergency reserve trader (RERT) mechanism. The Commission intends to assess this as part of the RERT assessment in this Review, including by assessing what is a strategic reserve and whether there is a need for a strategic reserve in the context of the NEM's reliability frameworks.

## 7.4 Directions and clause 4.8.9 instructions

Under clause 4.8.9 of the NER, AEMO may issue directions or clause 4.8.9 instructions to registered participants where it is necessary to do so to maintain or return the power system to a secure or reliable operating state. These are most likely to be:

- a direction to a scheduled generator to increase its output to the extent that this is physically possible and safe to do so[145]

143 Brattle Group, *International review of demand response mechanisms report*, accessed here http://www.aemc.gov.au/getattachment/9207cd67-c244-46eb-9af4-9885822cefbe/•The-Brattle-Group's-International-Review-of-Dema.aspx.

144 A standing reserve is a generic term to describe an ongoing obligation, for example, on the market operator to buy a set amount of capacity.

145 Directions only apply to scheduled plants or a market generating unit.

- a clause 4.8.9 instruction to a network service provider to disconnect load.

### 7.4.1 History of directions and clause 4.8.9 instructions

Similar to the RERT, directions and 4.8.9 instructions were initially conceived as transitional mechanisms with sunset clauses. However, in 2008, the Commission extended these provisions without sunset. In making its decision, it concluded that reliability directions were necessary as a last resort mechanism to maintain reliability of supply, particularly in light of a projected tightening in the supply-demand balance, and to provide the market with long-term confidence and certainty that AEMO is able to intervene to avoid load shedding.[146]

### 7.4.2 Operation of directions and instructions

Reliability directions that involve directing generation on may have distortionary effects on the market. Generators' capacity offers are driven by wholesale prices; however, a direction is not a price signal and could lead to sub-optimal generation outcomes, for example, additional capacity that may not be economic.

Generators must comply with directions regardless of the financial implications and they could suffer losses as a result.[147] Where a direction affects a whole region, intervention or 'what if' pricing would be required. Under 'what if' pricing, the spot price is determined as if the direction had not occurred. Directions also have a direct cost for consumers since both directed participants as well as other participants affected by a direction, may be eligible to seek compensation, the costs of which are ultimately recovered from consumers.

The efficacy of reliability directions is influenced by the physical and technical limits of plants. This is a known limitation. For example, the effectiveness of directions to wind generators to increase generation may be limited by the intermittent nature of that plant and the effectiveness of directions to thermal generators may be limited by the time it takes for offline thermal generating units to come online.

Participants issued with clause 4.8.9 instructions by AEMO are not entitled to compensation.

The Commission considers that directions and clause 4.8.9 instructions are not as efficient as the RERT. There are inefficiencies associated with involuntary load shedding under instructions since this mechanism does not differentiate between customers who place a very high value on continuing supply and customers who place a lower value on continuing supply. While involuntary load shedding does not have a direct cost to AEMO and to market participants as no compensation is involved, it can

146 AEMC, *NEM Reliability Settings: Information, Safety Net and Directions*, Final Determination, 26 June 2008.

147 However, a generator does not have to comply with a direction or clause 4.8.9 instruction if to do so would be a hazard to public safety, materially risk damaging equipment, or contravene any other law.

impose significant costs on end-customers, particularly when customers whose loads are being shed place a high value on reliability.[148]

Compare this to the RERT, whereby demand-side participants can curtail load voluntarily via demand response, albeit at a cost to the market. In the case of demand response via the RERT, customers will nominate to shed load by choice based on the value they place on reliability whereas load shedding through clause 4.8.9 instruction involves AEMO, in coordination with the relevant transmission network service providers (TNSPs), to shed load almost without discrimination regardless of the value customers attach to reliability.[149]

At the same time, emerging trends and drivers of change may also be having an impact on AEMO's ability to manage reliability. For example, unanticipated rapid changes in reserves may not leave AEMO will enough time to issue a direction or instructions. The availability of gas as an input may also affect whether or not a generator can increase its output.

Box 7.3 discusses the chain of events that occurred on 8 February and 9 February 2017. It provides context for how directions and instructions are used to manage reliability in the NEM and how the known limitations of directions and other drivers can affect outcomes.

**Box 7.3 South Australian 8 and 9 February events**

On 8 February 2017, amid a heatwave and running low on reserves, AEMO issued an LOR2 notice in South Australia in an attempt to get a market response from participants. Shortly after, the power system entered an insecure operating state.[150] At that point, AEMO conducted studies to determine appropriate actions to alleviate the insecure operating state of the power system including off-market options such as non-scheduled generation or load reductions and direction of capacity not available within the PASA 24-hour availability.

AEMO sought advice from Engie, owner of the Pelican Point combined-cycle gas power station, about the possibility of making one of its offline generating units available. Engie advised AEMO that this was not possible due to a lack of gas supply to run the unit. Furthermore, even if they did have enough fuel to run the unit, it would take at least four hours for the generating unit to be ready to supply electricity to the grid.

While Engie later revised its estimate, stating that it could be available for synchronisation within an hour and at full output within two hours if directed, on the day, this was still too long to return the power system into a secure

148 Noting that the market price cap applies when rotational load shedding occurs.

149 Rotational load shedding also occurs in consultation with the relevantjurisdictional system security coordinator (JSSC). They maintain a list of sensitive and priorities for load shedding.

150 For the power system to be reliable, it must not only have enough capacity to generate and transport electricity and reliable networks, but it must also be in a secure operating state.

operating state. After concluding that Engie would not be available in time, AEMO declared an LOR3 condition in SA and instructed ElectraNet to shed load. The power system returned to a secure operating state following load shedding.

At 21:30 that night, pre-dispatch PASA forecast an LOR2 for the following day, at which point AEMO contacted all scheduled thermal generators to confirm availability and enquire about start-up times and capacity for direction. On 9 February 2017, AEMO forecast and issued LOR2 notices in South Australia seeking a market response and advising the market that AEMO would intervene if one was not provided. No market response occurred and AEMO subsequently issued a direction to Pelican Point to increase generation. Pelican Point complied.

The difference between the two directions was the lead time. The 8 February event arose after a rapid deterioration in forecasts and AEMO declared an 'actual' LOR2 notice as the condition was happening. As a result, there was not enough notice given to the market to elicit a response. On 9 February, AEMO had already contacted generators about the LOR2 and, as a result, they would have been expecting a potential direction.

Source: AEMO, *System event report South Australia*, 8 February 2017 and AEMO, *NEM event - direction to South Australia generator*, 9 February 2017.

According to AEMO's operating procedures, when AEMO considers that it might have to intervene in the market by issuing a direction or clause 4.8.9 instruction, it will:[151]

- publish a market notice of the possibility that AEMO might have to issue a direction or clause 4.8.9 instruction so that there is an opportunity for a market response to alleviate that need
- determine and publish the latest time for intervention
- determine which registered participant should be the subject of a direction or clause 4.8.9 instruction
- issue a direction or clause 4.8.9 instruction verbally to the relevant registered participant, confirming whether it is a direction or clause 4.8.9 instruction.

During the 28 September 2016 black system event in South Australia, some participants noted that there was confusion as to whether or not they were being directed by AEMO under clause 4.8.9 (albeit for security purposes at the time) or whether they were being asked by AEMO to follow dispatch instructions.[152] AEMO has since

151 AEMO, SO_OP_3707, accessed from https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3707---Intervention-Direction-and-Clause-4-8-9-Instructions.pdf.

152 This was discussed at AEMO's *Market Suspension Technical Working Group* meetings in April-July 2017 and in AEMO, *Black System South Australia 28 September 2016*, March 2017, Accessed from https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

clarified the way it communicates directions by developing a standard script to be used when it issues a clause 4.8.9 direction.

Beyond the confusion experienced on 28 September, the question remains as to whether or not the current process remains fit for purpose, given, the discussed limitations of directions, that is, the physical and technical limits of plants (including intermittency of variable, renewable energy). Or, were there external factors to the NEM that were driving decisions as to whether to become 'available' or not. Importantly, AEMO can also use the RERT for such scenarios, under which it is trialling a product that will provide a 10-minute response time. These interactions and the associated costs and benefits of each mechanism will need to be assessed.

**Question 17 Efficacy of directions and clause 4.8.9 instructions**

**(a) Are reliability directions fit-for-purpose given existing trends such as the start-up time of generating units and other trends such as higher penetration of variable, renewable energy in the NEM?**

**(b) Are reliability directions and clause 4.8.9 instructions needed given the existence of the RERT?**

**(c) Is the notification process for directions - amount of notice given and clarity - adequate?**

## Abbreviations

| | |
|---|---|
| ACCC | Australian Competition and Consumer Commission |
| AEMC or Commission | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| ARENA | Australian Renewable Energy Agency |
| ASEFS | Australian Solar Energy Forecasting Systems |
| AWEFS | Australian Wind Energy Forecasting Systems |
| BNEF | Bloomberg New Energy Finance |
| CEFC | Clean Energy Finance Corporation |
| CER | Clean Energy Regulator |
| EAAP | Energy Adequacy Assessment Projection |
| EFI | Electricity Forecasting Insights |
| ERCOT | Electric Reliability Council of Texas |
| ESOO | Electricity Statement of Opportunities |
| JSSC | Jurisdictional system security coordinator |
| LNG | Liquefied natural gas |
| LOR | Lack of reserve |
| LRC | Low reserve condition |
| LRET | Large-scale Renewable Energy Target |
| NEFR | National Electricity Forecasting Report |
| NEM | National Electricity Market |
| NEO | National Electricity Objective |
| NER | National Electricity Rules |
| NMI | National metering identifier |

| | |
|---|---|
| NTNDP | National Transmission Network Development Plan |
| NTP | National transmission planner |
| PASA | Projected Assessment of System Adequacy |
| POE | Probability of Exceedance |
| PV | Photovoltaic |
| RERT | Reliability and Emergency Reserve Trader |
| RIT-T | Regulatory investment test for transmission |
| SCO | Senior Committee of Officials |
| SRMC | Short run marginal costs |
| TNSP | Transmission network service provider |
| TUOS | Transmission use of system |
| USE | Unserved energy |

# A Historical reliability performance of the NEM

This appendix explores the historical performance of reliability in the NEM. A number of measures are considered, including:

- changing frequency of reserve shortfall conditions
- use of reliability interventions
- projections of the ability of supply to meet demand in the NEM.

It is important to note that the NEM has experienced high levels of reliability. In the past decade, there have only been two periods where unserved energy was experienced.[153] These two periods both occurred in years with a greater number of reserve shortages, and are further discussed below.

## A.1 Unserved energy

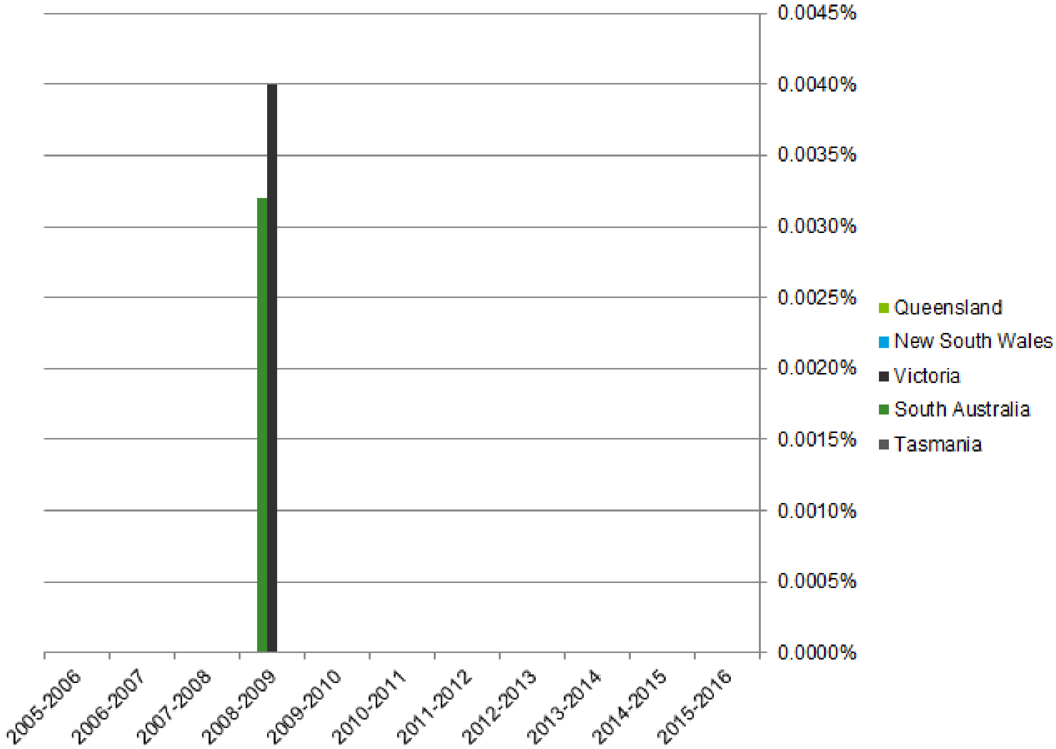
Unserved energy is a measure that has been used to assess the reliability performance of the NEM. Traditionally, there has been very little unserved energy in the NEM.[154] In the previous decade, there has only been two periods where unserved energy was experienced. Historical levels of unserved energy for each of the NEM regions up until 2016-17 are shown in Figure A.1. In all other years in the past decade, all regions have had no unserved energy. This indicates that with the exception a few small periods, there has been always been sufficient supply of energy available to meet consumer demand.

The Commission notes that there will be observed unserved energy in during 2016-17. However, this is not reflected in the figure below since the exact amount of this unserved energy is still being calculated by AEMO.

153 There have been other instances where consumer demand for electricity may not have been met. This could be the result of security related outages, or outages on the network that do not count toward measures of unserved energy.

154 Unserved energy excludes power system security events, network outages not associated with inter-regional flows and industrial action or acts of God. It also does not include interruptions to supply that are caused by failures of the intra-regional transmission network and outages on the distribution network.

## Figure A.1 Unserved energy in the NEM




Source: AEMO.

### Box A.1 Unserved energy in January 2009

There were two days in January 2009 where there was unserved energy: January 29 and 30. Unserved energy was experienced in South Australia and Victoria on both days.

On 29 and 30 January, Victoria and South Australia experienced elevated temperatures and demand. Indeed, there were record temperatures across Australia during this period:

- 28 to 30 January was the first time Melbourne had experienced three consecutive days of temperatures above 43C
- Adelaide had its third highest temperature ever (45.7C) on 28 January 2009
- Northern Tasmania recorded the highest temperatures ever, with Launceston Airport reaching 40.4C.

During this period, both South Australia and Victoria experienced record levels of demand:

- maximum demands on 29 January 2009 were the highest ever recorded in the Victoria and South Australia regions (at the time), reaching 10,494 MW and 3,383 MW, respectively

- maximum demands on 30 January 2009 were only slightly lower.

The weather during this period was considered to be close to a one in a one hundred year event.

Leading into 29 January 2009, NEMMCO (the predecessor to AEMO), forecast reserves were significantly higher than what was observed on the day. Actual reserves were much lower predominantly because of short notice reduced output from Victorian generators and Basslink. This occurred on both days and required NEMMCO to instruct load shedding.

- On 29 January 2009, 390MW of load was shed in Victoria and 140MW of load was shed in South Australia.
- On 30 January 2009, 390MW of load was shed in Victoria and 90MW of load was shed in South Australia.

As noted, there have been two more recent instances of unserved energy. These incidents occurred in February 2017 and are summarised in Box A.2.

**Box A.2 Unserved energy in February 2017**

There were two events in February 2017 that resulted in unserved energy:

- on 8 February 2017 there was unserved energy in South Australia
- on 10 February 2017 there was unserved energy in New South Wales.

**8 February 2017**[155]

At 3.00pm on 8 February 2017, AEMO projected there would be a shortage of reserves in South Australia for that evening. At 5.25pm a constraint equation managing flows on Murraylink[156] was violated. The violated constraint protects against voltage collapse in western Victoria. Following the violation of this constraint, the power system was in an insecure state.[157]

In order to return the power system to a secure operating state, AEMO sought advice from Engie on the availability of the offline Pelican Point unit. Engie advised AEMO that there was insufficient fuel to start the unit. Further, Engie advised AEMO that if gas could be sourced, it would be an additional four hours

155 AEMO, *System event report South Australia*, February 2017.

156 A DC interconnection between South Australia and Victoria

157 That is, the power system was not in a secure state. To be in a secure operating state, the power system must: be in a satisfactory operating state (that is, equipment must be operated within voltage and current limits and the frequency of the power system must be within defined frequency bands); and return to a satisfactory operating state following the occurrence of any credible contingency event in accordance with the power system security standards.

before the unit could ramp up and come online.

AEMO was also advised by AGL that a Torrens Island A unit was unavailable and a Torrens Island B unit was operating at reduced output due to high ambient temperatures.

At 6.00pm, the constraint equation on Murraylink was still binding, resulting in the power system having been in an insecure operating state for 35 minutes. AEMO concluded that it had no available supply-side options (that is, additional generation or controllable demand) to return the power system to a secure operating state.

Consequently, AEMO directed ElectraNet (the South Australian TNSP) to reduce load by 100MW. ElectraNet then instructed SA Power Networks (the South Australian DNSP) to shed 100MW of load.

By 6.20pm, AEMO became aware of 300MW of demand being shed,[158] which returned the power system to a secure operating state. At 6.40pm, AEMO instructed ElectraNet to restore all load, which ElectraNet confirmed occurred by 7.08pm.

The contributing factors that lead to the unserved energy were:

- demand was higher than had been forecast
- wind generation was lower than had been forecast
- thermal generation capacity was lower than forecast due to outages.

**10 February 2017**[159]

Leading into 10 February, AEMO had forecast that there would likely be insufficient reserves due to high temperatures driving high demand in New South Wales. By the morning of 9 February, AEMO was forecasting that the reserve level may reach negatives (that is, there would be the need to shed load). The NSW Energy Minister publicly encouraged consumers to reduce electricity consumption where possible to assist in relieving the reserve shortfall.

Coincident with peak demand of 14,181MW at 4.30pm on 10 February, the following incidents occurred:

- Tallawarra power station (408MW) suffered a forced outage due to a fault in its gas turbine.
- Colongra power station (650MW) was unable to start due to reduced gas

158 SA Power Networks have acknowledged that following the direction to shed load, an additional 200MW was shed due to an error in load shedding software. SA Power Networks, *Statement re load shedding event (8 February 2017)*, February 2017.

159 AEMO, *System event report New South Wales*, February 2017.

pressure in the fuel supply lines. Colongra had been operating at close to full output earlier in the day.

- A number of other thermal generators reduced output, mostly due to high temperatures reducing capacity and environmental restrictions.
- PV and wind generation reduced approximately 300MW, in line with AEMO's forecasts, between 5.00pm and 6.00pm.

At 4.30pm, constraint equations managing flows on both interconnectors between New South Wales and Queensland (that is, QLD-NSW interconnector (QNI) and the Terranorra interconnector[160]) started violating. As a result, the power system was not in a secure operating state.

After Colongra was unable to restart, AEMO determined that load shedding was required to return the power system to a secure operating state. At 4.58pm, AEMO directed TransGrid to reduce load which resulted in Tomago aluminium smelter reducing its load by 290MW.[161] Tomago's load was completely restored by 6.01pm.

## A.2 Levels of reserve

Reserve levels is a concept defined in the NER and refers to the amount of spare capacity available giving consideration to amounts of generation, forecast load and load response and scheduled network service provider capability. It indicates the difference between available resources to meet demand for energy, and the level of energy demanded.

There are currently three different lack of reserve conditions in the NEM, each corresponding to the extent of the availability of reserve. These levels are:

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

AEMO declares lack of reserve conditions through market notices. Figure A.2 shows the number of lack of reserve market notices that have been issued by AEMO over the past 10 years.

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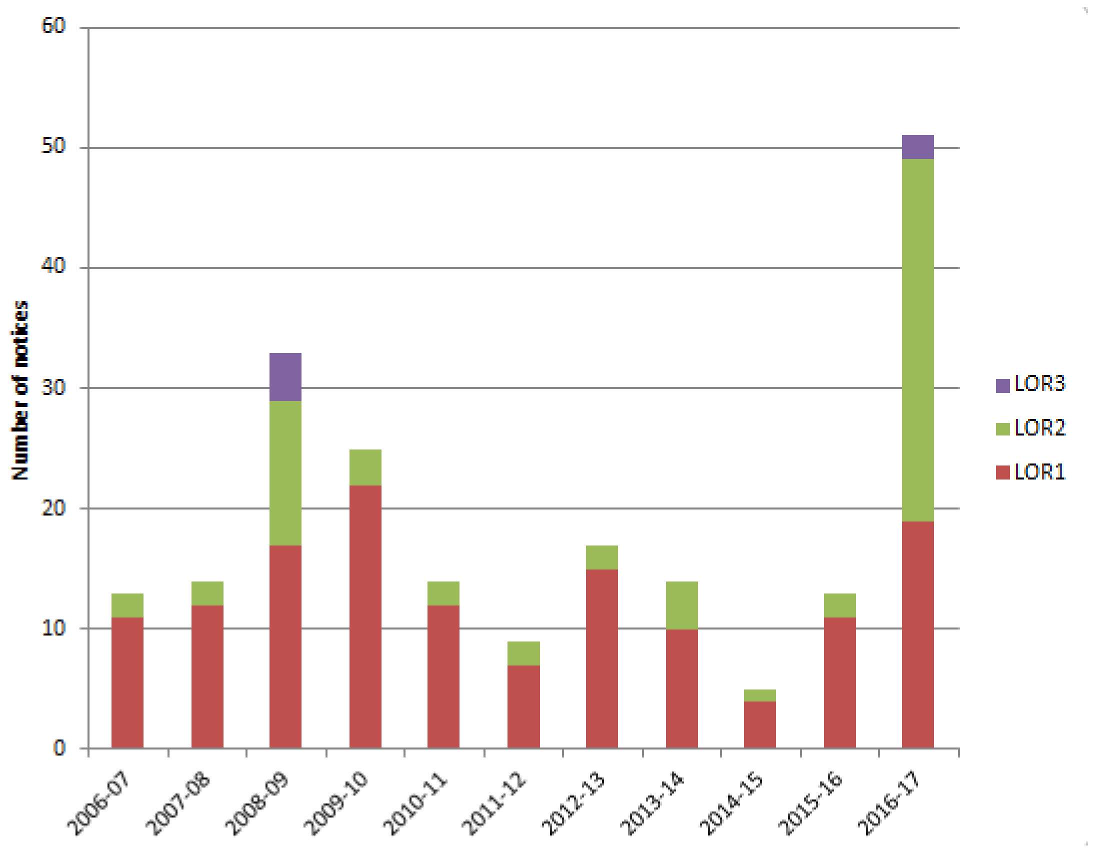
160 The Terranorra interconnector was formerly known as Directlink.

161 Prior to AEMO directing the Tomago smelter to shed load, AGL Macquarie had been operating the Tomago smelter at reduced load. This consisted of Tomago have one of three potlines offline.

**Figure A.2 Lack of reserve conditions by number of LOR1, LOR2 and LOR3 notices issued**



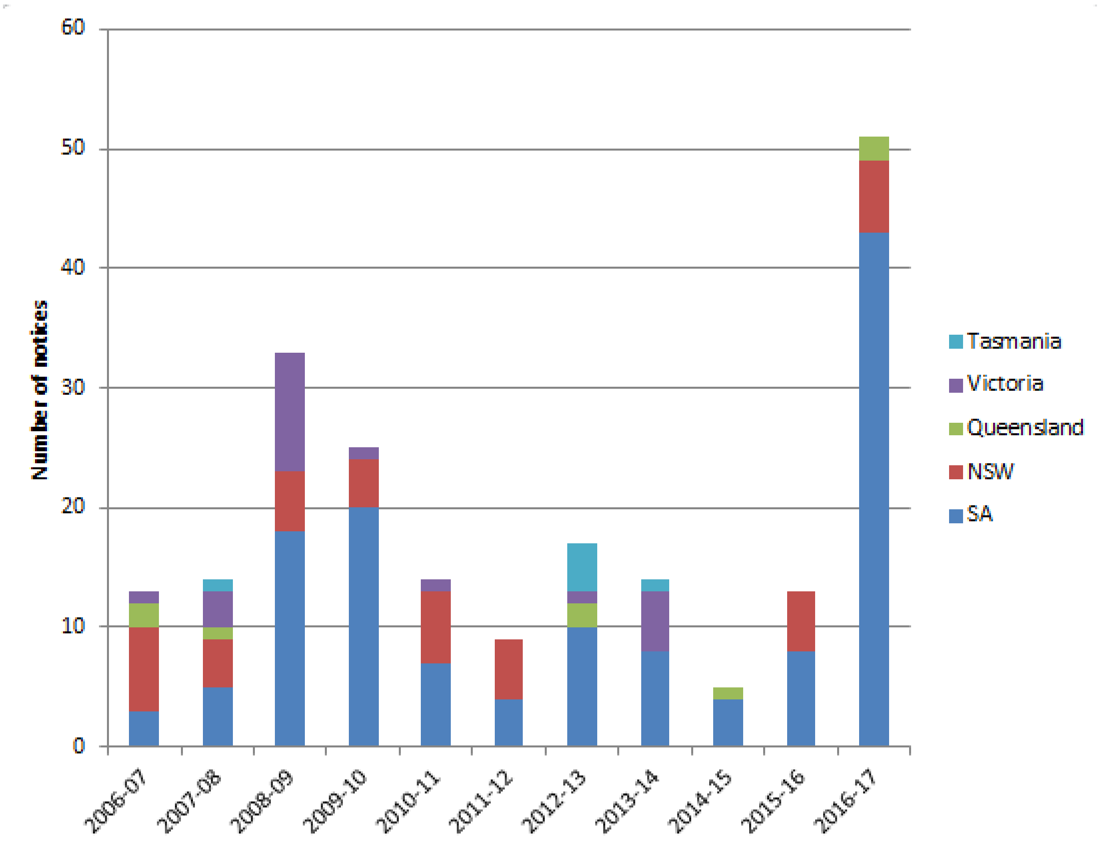

Source: AEMO, *Market notices*.

Figure A.2 shows that following 2008/09, there had been a general decline in the number of lack of reserve notices issued by AEMO. However, this trend was reversed in 2016/17 which experienced the highest number of lack of reserve notices in the past ten years. Other observations include:

- 2016/17 was the second 12 month period in the past decade where an LOR3 was declared.
- 2016/17 had more LOR2 notices than LOR1 notices. Normally, one would expect the number of LOR1 notices to exceed the number of LOR2 notices. This because the amount of reserve available would typically reduce in an incremental manner, leading to an LOR1 notice being issues prior to an LOR2 notice. This was not the case in 2016/17, predominantly because when the loss of the Heywood became credible and LOR2 condition was declared for South Australia without first having declared an LOR1 condition.

A breakdown of the regional allocation of lack of reserve notices is shown in Figure A.3.

**Figure A.3 Lack of reserve conditions by total number of notices issued by AEMO, by region**




Source: AEMO, *Market notices*.

Figure A.3 shows that over the past decade, lack of reserve notices have predominantly been issued for South Australia. This is most clearly demonstrated in 2016/17.

## A.3 Use of Reliability and Emergency Reserve Trader

### A.3.1 Historical use of the RERT

AEMO (and its predecessor NEMMCO) has entered into reserve contracts three times since the commencement of the NEM. In all three occasions, the contracted reserves were not dispatched, that is, not called upon.

The three times that the market operator has entered into reserve contracts are:

1. From 31 January 2005 to 4 March 2005 (33 days), 84MW of reserve capacity was contracted. These reserves were contracted to address a reserve shortfall that did not eventuate due to lower than expected temperatures reducing demand.[162]

162 AEMC Reliability Panel, *Review of the Reliability and Emergency Trader - Final report*, April 2011, p. 6.

2. From 16 January 2006 to 10 March 2006 (54 days), 375MW of reserve capacity was contracted. The forecast shortfall reflected the impact of delays in the commissioning of Basslink and Laverton North power station.[163]

3. From 15 January 2014 to 17 January 2014, 650MW of reserve capacity contracted on each of these three days. AEMO contracted for reserves under the short-notice RERT, to address an LOR2 condition.[164]

In all three cases where reserve contracts were entered into, the reserves were not dispatched as the forecast reserve shortfalls did not eventuate. However, costs were still incurred as in some instances, the contracts included an availability-type payment which was paid to reserve providers to be made available for the duration of the contract. The Commission understands that the availability payments in each of the three instances where reserve contracts were entered into were:[165]

- $1.035m ($12,321 per MW) for the 31 January 2005 – 4 March 2005 period
- $4.352m ($11,605 per MW) for the 16 January 2006 to 10 March 2006 period
- zero for the 15-17 January 2014 period.

AEMO has issued an expression of interest for the provision of reserves under the long-notice RERT for summer 2017/18 in Victoria and South Australia. The expression of interest closed on 7 July 2017. Following this, AEMO is now issuing an invitation to tender for this provision.[166]

In addition, AEMO also issued an internal expression of interest for RERT panel seeking expressions of interest from entities in Victoria, South Australia, Tasmania, Queensland, NSW and the ACT who may be able to provide energy on short- and medium-notice as part of a RERT panel. This expression of interest closed on 7 July 2017, although the Commission understands that the deadline was extended to 21 August 2017 for South Australia and Victoria.

## A.4 Projections of unserved energy

In its 2017 Energy Supply Outlook, AEMO published projections of expected unserved energy under a range of scenarios. Figure A.4 shows AEMO's projected unserved energy in the base case scenario.[167]

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163 Ibid.

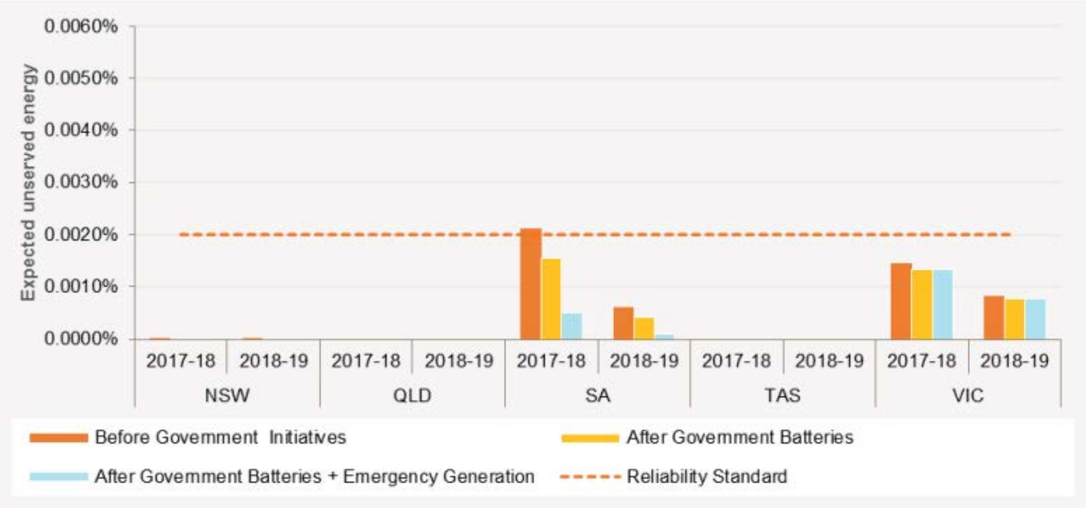
164 AEMC, *Extension of the Reliability and Emergency Reserve Trader - Consultation paper*, 14 June 2016, p. 16.

165 Ibid.

166 The amount of reserve sought by AEMO is up to 670MW; however, AEMO has noted that this number is subject to revision. AEMO, *Energy Supply Outlook*, June 2017.

167 The base case assumes Generation (including Pelican Point, Swanbank E and Tamar Valley power stations) operating at capacity, with no planned outages over critical periods. Government battery initiatives operating as planned for next two summers. AEMO, *Energy supply outlook*, June 2017.

**Figure A.4 Projected unserved energy**




Source: AEMO, *Energy Supply Outlook*, June 2017, p. 12.

Under AEMO's probabilistic projections, unserved energy is not expected to exceed 0.002% in 2017/18 or 2018/19. This assessment assumes:

- various government energy storage initiatives are in place by the summer of 2017/18[168]
- there are no planned outages of generators during critical periods
- Pelican Point power station,[169] Swanbank E power station[170] and Tamar Valley power station[171] return to service.

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168 The South Australian Government aims to deliver 100MW of battery storage and the Victorian Government aims to deliver 40MW of battery storage. AEMO, *Energy Supply Outlook*, June 2017, p. 4.

169 Pelican point has returned to full service and now provides 478MW capacity in South Australia.

170 The Queensland government has committed to the return of Swanbank E power station to service from early 2018. This will provide an additional 385MW capacity in Queensland.

171 AEMO has been advised by Hydro Tasmania, the owner of Tamar Valley power station, that this plant will be withdrawn from the NEM following May 2017 but it available for recall with less than three months' notice.

# B Demand response

Demand response involves customers changing their usage of electricity in response to signals to do so. Demand response is a form of demand side participation, which are actions that a consumer can take to alter or shift its electricity consumption in response to changing market conditions. In the NEM, the supply side of the market provides electricity at a price, and the demand side (that is, consumers) directly or indirectly through a service provider respond to the price or the value of the product or service presented to them based on that price.

Technological developments, market and regulatory developments[172] and innovation by demand side management providers over the past decade has made it easier for consumers across all sectors (industrial, commercial and residential) to adapt their consumption patterns in order to manage their electricity consumption, and, in turn, their expenditure:

- Home energy management systems can provide demand response and deliver load reductions in a way that goes largely unnoticed by the customer.
- Price signals, either in the form of cost reflective pricing or direct incentives, can encourage customers to shift energy use away from peak times, avoiding inefficient investments in energy equipment and more drastic load shedding events.
- Given appropriate incentives, voluntary load reductions by commercial and industrial users could serve as an alternative to involuntary load shedding to address lack of reserve conditions.

By actively participating in the market through such options, demand for electricity services is effectively met through the lowest cost combinations of demand and supply options. Other demand side participation options provider opportunities for, typically larger consumers, to use their load in a way that maximises its value.

A 2016 survey for the AEMC suggested that there is at least 235 MW of demand response under contract to retailers, mostly involving exposure to the wholesale market spot price and 310 MW contracted to specialist demand side-management companies.[173] . More recently, preliminary information from ARENA's reliability demand response trial suggests that about 700MW of potential demand response capacity could be made available by 1 December 2017 and almost 2000MW of capacity by the end of 2018. ARENA noted that demand response capacity is evenly spread

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172 Reforms flowing the AEMC's Power of choice review have laid foundations for an energy system where more engaged and better informed energy shoppers have greater access to new products and services like solar, storage, electric vehicles and smarter consumption management. Key reforms include new rules to support competition in metering and cost-reflective prices.

173 See Oakley Greenwood, Current status of DR in the NEM – Interviews with electricity retailers and DR specialist service providers, http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism.

among industrial, commercial and residential users, with a diversity of technologies, including industrial load curtailment and batteries.[174]

It is generally accepted that there are four different types of demand response, based on the underlying rationale for why it is being used:

- Ancillary services demand response – demand response employed for use in ancillary services markets, for example, to respond quickly to brief, unexpected imbalances in supply and demand to return the grid to frequency utilised in the FCAS markets.
- Network demand response – demand response employed to manage peak demand within a particular transmission or distribution network.
- Wholesale demand response - market driven demand response used to avoid buying electricity driven by either at times when wholesale spot prices are high, or by participant contract positions.
- Reliability demand response – demand response employed as an emergency lever during supply emergencies, centrally dispatched or controlled to avoid involuntary load shedding and rolling blackouts.

We discuss each of these in turn below.

## B.1 Ancillary services demand response

Demand response is one source (in addition to generation) that could be used to provide the Frequency Control Ancillary Services (FCAS) that AEMO uses for maintaining system frequency within the bounds specified by the frequency operating standards, both under normal operating conditions and/or to restore frequency following a contingency event such as loss of a major generating unit or transmission line. This was recognised by the Commission, back in 2012, when the final report for the *Power of choice* review recommended (amongst other things) that a new category of market participant should be created to unbundle the sale and supply of electricity from non-energy services, such as ancillary services.[175]

Following from this recommendation, in 2015, the COAG Energy Council submitted the *Demand response mechanism and ancillary service unbundling* rule change request to the Commission. While the Commission decided not to implement the proposed demand response mechanism (see below), the ancillary services unbundling component of the rule was implemented, with the rule coming into effect on 1 July 2017. This effectively results in ancillary service unbundling by creating a new type of market participant – a market ancillary service provider – to offer customers' loads into

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174 This was highlighted in an email to ARENA's stakeholders and has also been reported in the media. See http://www.abc.net.au/news/2017-07-13/household-electricity-trading-app-may-be-funded-by-government/8707010.

175 AEMC, Power of Choice – Stage 3 DSP Review Final Report, 30 November 2017, p. ii.

the FCAS markets. In implementing this rule change request, AEMO identified a potential issue that is likely to reduce the benefits arising from the unbundling. This rule change request was recently considered by the Commission through an expedited process, with a final rule being made that allowed all loads to be eligible to be used for ancillary services in the NEM.

Therefore, there are no regulatory barriers to ancillary services demand response in the NEM. Further, it is likely that demand response will have a greater role in ancillary services in the NEM following the conclusion of recent rule changes by the AEMC.

In addition, the NEM is currently experiencing a significant shift away from conventional synchronous generators and towards new, non-synchronous technologies, such as wind farms and solar panels. The impact of non-synchronous generation on how the system is maintained in a secure state is an important focus. AEMO has identified that power system security in a future system with low levels of synchronous inertia may require resources that can be activated in milliseconds, rather than seconds as is currently the case.[176] Switchable loads and storage could provide a fast FCAS response in this regard. Such issues, including how demand response could provide such services, are being considered through the Commission's *Frequency control frameworks review*, which is considering what market and regulatory arrangements are necessary to support effective control of system frequency in the NEM, including fast frequency response.

## B.2 Network demand response

Technology surrounding the grid is changing. In recent years, more and more consumers have been adopting decentralised energy resources. New forms of generation, including solar PV and battery storage, are becoming cheaper and better – and as a consequence, more widespread and viable at a small scale. At the same time technology innovation is allowing for resources to be deployed and coordinated in unprecedented ways, giving rise to new forms of monetisation, trade and ownership. The technological innovation also means that NSPs now have a much more diverse range of solutions (commonly referred to as non-network solutions) compared to the traditional network options.

Network demand response is where, instead of network businesses augmenting or replacing the network (that is, making investments in poles and wires) to meet the peak demand, consumers reduce their demand at certain times so that the resulting (lower) peak demand can be accommodated within the existing network capacity. There is a geographic element to network demand response, in order for network demand response to be successful at managing peak demand it needs to be located in the right part of the network.

The key principle of network regulation in the NEM is that it is based on incentivising NSPs to provide services as efficiently as possible. It does so by locking in NSPs' revenue allowances prior to each regulatory control period. With revenue locked in,

176 AEMC, System Security Market Frameworks Review, Consultation Paper, 8 September 2016, p. 24.

NSPs are incentivised to provide services at the lowest possible cost because their returns are determined by their actual costs of providing services. If NSPs reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods. Since NSPs are incentivised to provide services efficiently, they are provided with discretion to choose how they provide network services.

Under incentive regulation, it is not the role of the regulatory framework to determine what the ideal or efficient level of uptake of non-network solutions should be. Rather, the current framework provides a number of incentives and obligations for non-network options to be adopted where it is efficient to do so. For example:

- *Regulatory investment tests for distribution and transmission* require distribution network service providers (DNSPs) and TNSPs to assess the costs and benefits of each credible investment option (that is, traditional network build or use of non-network options) to address a specific network problem to identify the option, which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).
- *Demand management incentive scheme and demand management innovation allowance*: The DMIS provides DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme will reward DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers. The DMIA provides DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs. The allowance will be used to fund innovation projects that have the potential to deliver ongoing reductions in demand or peak demand.

Therefore, the Commission considers that there are no regulatory barriers to network demand response being used. As uptake of distributed energy resources further increases due to such devices becoming cheaper and better, we expect to see more innovative solutions being used by networks in order to deliver a safe, reliable, secure supply of energy to consumers. Indeed, the Commission considers that there are a number of examples under the current regulatory framework where demand response is being used for network demand response, most notably Reposit's energy management software, as well as the deX platform for the trading of decentralised energy resources.

The Commission is also currently undertaking work in several areas that will further facilitate the potential use of network demand response in the future, as distributed energy resources become more prevalent:

- We are currently considering two rule changes on the contestability of energy services from the COAG Energy Council and the Australian Energy Council. These rule change requests are related to which services should be economically regulated. In particular, it seeks (amongst other goals) to promote contestable provision of a range of energy services.

- Further, in the Commission's 2018 *electricity network economic regulatory framework review* we will review the financial incentives that network businesses face in delivering economically regulated services under the existing regulatory framework. This analysis will be particularly focussed on the financial incentives network businesses face to deliver their regulated services using distributed energy resource based solutions relative to traditional network solutions.

Such reforms are important since these will make sure that there is efficient take-up and facilitation of distributed energy resources (and so, potentially, demand response) where it is efficient to do so.

## B.3 Reliability demand response

Demand response can be a resource at times when forecast demand for electricity exceeds forecast supply. It is worth noting that the current NER already allows for reliability demand response: demand response providers can participate in the RERT, and AEMO is able to direct Registered Participants (including load) in the event of a lack of reserves.

However, it is worthwhile exploring whether reliability demand response could be better incorporated into the NEM framework. Even small amounts of demand response can avoid involuntary load shedding. For example, in South Australia on 8 February 2017, AEMO requested 100 MW of load shedding to address a demand/supply imbalance during a heatwave. And, in NSW on 10 February 2017, AEMO requested 290 MW from the Tomago aluminium smelter. This load shedding represented 3.2 per cent and 2 per cent of peak demand in those states on those days respectively. An alternative to these AEMO interventions would be to use demand response or voluntary load reduction, which would shift the costs and benefits of addressing reliability constraints in the NEM. Demand response would allow consumers to assess the value of consumer electricity versus compensation for reducing consumption, rather than centrally coordinated decisions about how to reduce consumption.

Such issues of how we could better incorporate reliability demand response into the NEM are being considered through this Review, which is also being informed by the current AEMO and ARENA pilot of a demand response initiative this summer to manage electricity supply during extreme peaks and grid emergencies.

The trial is a three year program is to be piloted in South Australia, Victoria and NSW to free up temporary supply during extreme weather and unplanned outages. A range of different demand response approaches are being demonstrated. Under the initiative, ARENA will provide grants to fund technology for energy users to become demand response-enabled, including metering, monitoring, storage and distributed generation equipment and set up costs. It is worth noting that this grant will effectively be an "availability payment", which are not currently paid in the RERT mechanism. A common feature of demand response reliability mechanisms in overseas markets has been the provision of availability payments. A key question to be considered through the trial is whether offering such payments alter incentives to participate.

The intent is that a rule change request to permanently implement the mechanism will be submitted to the AEMC in early 2018.

## B.4 Wholesale demand response

A wholesale demand response mechanism was considered by the Commission in 2016, in which we decided not to implement the specific wholesale demand response mechanism proposed since it would be costly to implement given customers can already contract with retailers and specialist providers, and can choose to be exposed to the wholesale market spot price through their retail contract.[177] The Commission also found that the proposed mechanism was costly, distortionary and adds little benefit to consumers, because the benefits of demand side participation can, and already are, accessible under current arrangements.

In the final determination for that rule change request, the Commission acknowledged that there may currently be commercial reasons that complicate access to demand response for some consumers, but implementing a market wide mechanism in the Rules, at considerable cost to all consumers, is not the appropriate vehicle to address these reasons, nor would it encourage an efficient level of demand response. The reasons behind the Commission's decision are summarised in Box B.1.

**Box B.1 A mechanism for wholesale demand response**

Following recommendations made by the Commission in its *Power of Choice review* (PoC) to introduce a demand response mechanism, on 30 March 2015, the AEMC received a rule change request from the COAG Energy Council seeking to create a demand response mechanism (DRM) in the NEM.

The proposed DRM would create a new class of market participant, a demand response aggregator (DRA). The DRA would facilitate large energy users to act as though they were non-scheduled generators in the wholesale market, and would receive reimbursement for reducing energy demand in response to high price events. Under the proposed DRM, the retailer would bill the customer on their baseline consumption for a demand response event. In the wholesale market settlement, generators would be paid for energy generated, and the DRA would be paid for the demand response energy. The DRA would pay the customer for their demand reduction based on commercial arrangements negotiated between the two parties.

The proposed DRM was a variation from the original DRM specifications proposed by the Commission as part of its PoC recommendations, where it was envisaged that demand response would be scheduled by AEMO through central dispatch rather than by a demand response aggregator outside of it.

In November 2016, the Commission published its decision not to implement the proposed mechanism. The Commission considered that implementing the DRM

177 http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism.

would not be in the long-term interests of consumers for the following main reasons:

- There are no regulatory barriers to the continued proliferation of demand response that is currently underway. The demand side can - and is - already participate in a number of ways and can include actions such as, peak demand shifting, changing consumption patterns or load control of consumption and consumers generating their own electricity.
- The Commission was unable to find evidence of a relevant market failure that would prevent the current demand side participation arrangements in the market. There was also no evidence that there are insufficient incentives on retailers to offer demand response services.
- Only scheduled (or semi-scheduled) generation and loads are included in central dispatch, which determines wholesale market prices. Demand response under the proposed DRM would not be scheduled (it would be self-scheduled by a DRA) and would have no effect on the wholesale price.
- AEMO's pre-dispatch and dispatch processes currently do not explicitly take into account the intentions of non-scheduled market loads (such as demand response) to respond to price signals. As a result, demand response cannot directly compete with generation as the COAG Energy Council considered it would.

Other reasons included the cost of implementing a DRM, that the DRM would not necessarily alleviate network constraints and defer network expenditure and that the DRM could have unintended consequences and could create distortions in the market.

Since that time there has been increasing focus on how to better incorporate renewable, intermittent generation into the power system – an issue first identified by the Commission in the 2015 strategic priorities. Wholesale demand response or better incorporation of the demand-side could assist in addressing the variability of such generation sources, and addressing any potential or perceived reliability problems in the NEM. Such issues, including a wholesale demand response mechanism, are being considered by the Commission through this Review - see chapter 5.