AEMC

REVIEW

Australian Energy Market Commission

FINAL REPORT

RELIABILITY FRAMEWORKS REVIEW

26 JULY 2018

INQUIRIES

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Reference: EPR0060

CITATION

AEMC, Reliability Frameworks Review, Final Report, 26 July 2018

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.

SUMMARY

1 This report is making a series of recommendations to implement and develop mechanisms in the NEM aimed at supporting reliable outcomes for consumers at lowest cost, including options to facilitate demand response in the wholesale market and to improve transparency of the forecasts that underpin decision making. Rule change requests are recommended to implement these reforms. This report also concludes a number of Finkel Panel recommendations concerning reliability that were directed to the AEMC. In addition to a demand response mechanism, the need for a strategic reserve is being considered through the *Enhancement to the Reliability and Emergency Reserve Trader* rule change process. Finally, the Commission has concluded that a US-style day-ahead market would not be suitable for improving reliability outcomes in the NEM.

Context

2 The full force of transformational change is in motion across the national electricity market, driven by government policy, changing consumer preferences and rapidly evolving technology. The generation mix is moving from a system supported mostly by larger, synchronous generation to a system, with a comparatively greater number of generators, larger volumes of variable renewable generation, customer-connected distributed energy resources as well as storage capability and a more active demand side.

3 These fundamental step changes in power system technologies raise new opportunities for the entire community. They also raise new risks for the reliability and security of electricity supply. Reliability and security are two core concepts that underpin the NEM. Reliability means that the power system has an adequate amount of capacity (generator, network, demand response) to meet consumer needs. This is distinct from the concept of security whereby a secure power system is one that operates within defined technical limits.

4 The Commission's *Reliability Frameworks Review* is a core part of our reliability and security work program. This Review has examined existing arrangements to make sure they are flexible and modern enough to facilitate the transition across all parts of the NEM.

5 We have now concluded this stage of this review and provided a set of recommendations for this changing environment directed to protecting consumers and keeping the cost of transition as low as possible. This includes concluding a number of Finkel Panel recommendations directed to the Commission, that sought to facilitate an orderly transition in the NEM.

Reliability and security performance

6 The current reliability standard was met for the NEM in 2016/17 consistent with previous years. Based on modelling and other analysis, the reliability standard will continue to be met in all regions of the NEM in the near to medium term.

7 Nevertheless, recent events in the NEM, such as load shedding in South Australia and New South Wales and the announced closure of generators, have led to a greater focus on reliability. The value that consumers place on reliability of supply is increasingly being

debated in the context of a reliability standard that is designed to allow for involuntary loss of supply on limited occasions.

8 In relation to security, however, keeping the power system operating within its technical limits for all credible contingencies was not achieved on a number of occasions in 2016/17. It is becoming harder for AEMO to manage the power system, reflected by the mixed security performance of the power system, resulting in a less secure power system and increased risks of load being interrupted.

9 Improving security outcomes in the NEM remains a priority, and is critical in ensuring that there is confidence that the system will be able to immediately respond securely to the operational dynamics bought about by the transition. The challenges in managing power system security are being addressed by the AEMC through its system security work program. To date, the AEMC has made seven new rules to assist in meeting the security needs of the transforming system. The AEMC continues to work closely with AEMO to identify further system security and operational challenges so that the system operator is equipped to manage, and market participants can contribute adequately to, power system security in the most effective and least cost ways.

10 This transformation is also occurring against a backdrop of uncertainty over nationally-consistent, long-term policy settings on emissions reductions and the mechanisms that will be used to achieve those reductions. Uncertainty over an emissions reduction mechanism is being addressed through the Energy Security Board's (ESB) proposed National Energy Guarantee (Guarantee), which seeks to integrate energy and climate change policy instruments in the NEM to provide investors with the certainty they need to make long-term investments. The Guarantee is a foundational component of a broader, ESB work program to support this transition of Australia's energy system.

What is reliability?

11 Reliability means that the power system has an adequate amount of capacity (generation, demand response and network capacity) to meet consumer needs.

12 A reliable power system therefore requires adequate investment and disinvestment as well as appropriate operational decisions, so that supply and demand are in balance at any particular point in time. In a reliable power system the expected level of supply will include a buffer, known as reserves. Expected supply will be greater than expected demand. This allows the actual demand and supply to be kept in balance, even in the face of shocks to the system, known as "credible contingencies".

13 Reliability is currently delivered in the NEM through investment, retirement and operational decisions that are underpinned by various market structures. The framework is supplemented by a series of mechanisms that allow the system operator to intervene in the market in specific circumstances.

14 The National Electricity Rules (NER) specify the reliability standard for the NEM, currently set at 0.002 per cent expected unserved energy. As system operator, AEMO then incorporates the reliability standard within its day-to-day operation of the market, e.g. by providing

information to the market as to whether or not the reliability standard is being met.

15 This Review has focussed on analysing and making recommendations around key aspects of the current reliability framework:

- increasing transparency of information available to the market
- integrating demand into the wholesale market
- improving wholesale market outcomes
- examining the market interventions framework in light of its increased use.

Improving information available to the market

16 Provision of information is critical to reliability outcomes in the NEM by allowing market participants, the system operator, regulators and policy makers to make better-informed decisions.

17 *Forecasting*

18 Particularly important is the role of forecasts. The role of forecasting in the NEM is to provide market participants and AEMO with the best information available at any given moment in time to inform decisions they need to make today. To do this, forecasts need to be well-understood via the publication of details on how they are produced, the assumptions used and how previous forecasts compare to actual outcomes, so informing how forecasts are used by participants. In order to improve on this we are making three recommendations to promote transparency of the forecasting process, while minimising the costs that will flow through to consumers.

RECOMMENDATION	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
A rule change request be submitted to require AEMO to consult on and prepare a new guideline that it will follow in developing and amending its forecasting methodologies.	The AER should submit a rule change request by **October 2018** requesting these amendments. This timeframe would be in line with changes to be considered through the development of the Guarantee.
AEMO to continuously provide forecast deviation data, after engaging with industry participants on the content and structure of the new data reports.	AEMO to undertake consultation with participants (i.e. those who would use the data) to determine what would be useful to report on. AEMO would then implement the changes through its systems by the end of 2018. The Commission understands that AEMO is currently working on a number of forecasting initiatives.
A rule change request be submitted for the	The AER should submit a rule change

RECOMMENDATION	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
AER to consult on and prepare a guideline on how it will report on the differences between forecast and actual values in the medium-term projected assessment of system adequacy (PASA), short-term PASA and pre-dispatch forecast processes and produce a quarterly public report in accordance with the guideline.	request by **October 2018** requesting these amendments. This timeframe would be in line with changes to be considered through the development of the Guarantee.

19 *Electricity contract data*

20 Contract markets play an important role in supporting reliability in the NEM. However, there is a lack of visibility of the contract market – particularly for over-the-counter (OTC) contracts – meaning that it is not possible to gauge the health of the contracts market. With this in mind, in its *2018 Retail energy competition review* the Commission noted repeated concerns from retailers about the contract market being a barrier to entry or expansion for smaller retailers. There is therefore a need to increase transparency of electricity contracts, assisting market participants, end users as well as policy and regulatory agencies to make efficient decisions.

21 The Commission notes the ACCC's final report of its Retail Electricity Pricing Inquiry also contains concerns about transparency in the contracts market and recommends all OTC trades be reported to a repository administered by the AER.

22 Given the importance of this information, the Commission is therefore committed to working with industry to make data on electricity contracts available to the market in a form that enhances the transparency of the wholesale cost of energy.

Integrating demand into the wholesale market

23 The wholesale market facilitates the trade of electricity between suppliers and consumers. Historically, the demand side has been passive in its involvement in the wholesale market. However, this is changing as consumers are becoming increasingly capable and willing to actively participate.

24 An active demand-side characterised by the active participation of consumers promotes efficient outcomes in the wholesale market. In particular, demand response can be more cost effective for both the consumer and the power system than building new peaking capacity. For those consumers able to participate in the wholesale market, it allows them to decide, at any particular point in time, if the value to them of services enabled by the supply and consumption of electricity is greater or less than the costs of supply at that time.

25 A more active demand side will be a feature of the future of the NEM. For this reason, the Finkel Panel recommended that the AEMC undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market.

26 The ACCC also recommended, in the final report of its Retail Electricity Pricing Inquiry, that a mechanism for third parties to offer demand response directly into the wholesale market should be developed.

27 We consider that there is a package of recommendations that seeks to remove barriers to demand response and provides a range of additional tools for parties to undertake wholesale demand response, while preserving the market-based arrangements in the NEM that allow for flexible and resilient frameworks. These recommendations don't lock in a particular type of demand response, but instead leave it open for different types of demand response to be provided in the wholesale market in the future from new technologies and new business models.

28 There are many different types of demand response - e.g. firm and non-firm demand response. Firm demand response can be considered dispatchable - the reduction in output can be in response to a particular instruction. Non-firm demand response, e.g. whereby consumers may receive a voluntary request to reduce consumption but are able to elect whether they will do so, is more variable and typically cannot be bid into the market.

29 While this package of recommendations offers the benefits discussed above, it also has an element of complexity that will need to be addressed as these recommendations are progressed further. As a result, issues in relation to feasibility, practicability and costs will need to be explored further.

RECOMMENDATION	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
In order to facilitate increased demand response in the wholesale market, and in response to Finkel Panel recommendation 6.7 we consider that: • A voluntary, contracts-based short-term forward market be implemented that would allow participant-to-participant trading of financial contracts closer to real time. This will provide the demand side with more opportunities to lock in price certainty, making it easier for large demand side consumers to engage in the wholesale market and demand respond (i.e. reduce consumption) in response to expected wholesale prices. • Demand response aggregators and providers should be able to be recognised on equal footing with	AEMO should undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market. The Commission understands, through their submission to this Review, that TEC and PIAC will submit a rule change request to the AEMC to implement a wholesale demand response mechanism. If these stakeholders have not submitted a rule change request by the end of August 2018, then the Commission will develop a mechanism that the Energy Security Board can consider for submission to the AEMC as a rule change request. This will be supported by testing the practicability and costs of these measures through "in-market demand response" trials

RECOMMENDATION	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
generators in the wholesale market and so offer wholesale demand response transparently into the market. • Consumers should be allowed to engage multiple retailers / aggregators at the same connection point (multiple trading relationships). This will promote competition between retailers, supporting new business models for demand response and providing consumers with greater opportunities to engage in wholesale demand response with parties other than their incumbent retailer.	that AEMO and ARENA have indicated will take place. Given the complexity associated with this, the trials can play an important role in assessing alternative options, identify likely implementation issues and provide guidance on the best implementation option. Subject to the outcomes of relevant trials, AEMO should develop a rule change request to submit to the Commission to implement multiple trading relationships. That is, how existing trading and consumer protection arrangements need to change to allow for more than one retailer or aggregator at a connection point. As with a wholesale demand response mechanism, the trials will play an important role given the practicalities and costs involved.

Improving wholesale market outcomes

30 The buying and selling of electricity as well as associated financial products, via contract and wholesale spot markets is the main mechanism through which reliability is delivered in the NEM. Market participants make investment and operational decisions based on these market signals and financial exposures.

31 The core objective of the existing reliability framework in the NEM is to deliver desired reliability outcomes through market mechanisms to the largest extent possible. In the event that the supply/demand balance tightens, spot and contract prices would rise, which will inform operational decisions and provide an incentive for entry and expansion, addressing any potential reliability problems as or before they arise. This would then lead to a widening of the supply/demand balance and prices would fall in response.

*32 Day-ahead market*s

33 In considering the resilience of existing reliability frameworks given the market transformation that has already occurred and is on foot, the Finkel Panel recommended that the AEMO and the AEMC should assess the suitability of a 'day-ahead market' to assist in maintaining system reliability.

34 The Commission also looked at ahead markets in other jurisdictions to see what features in those markets could improve on what currently is in the NEM. There are a number of options for the design and implementation of ahead markets. Throughout this Review the

Commission has considered two common designs:

- a European-style ahead market that facilitates participant-to-participant trades ahead of real-time
- a US-style ahead market that facilitates participant-to-system operator actions as a tool to schedule operations.

35 Despite not having a formalised day-ahead market the NEM has many features which play a similar role. These features include information that is provided to AEMO as part of the pre-dispatch process, with rebidding down to five minutes before real time supported by a liquid financial derivatives market. Rebidding allows participants the flexibility to adjust their position in response to new information as it becomes available, including changes in market conditions as well as responding to offers or bids of other participants.

36 The Commission does not consider that a US-style ahead market (that would change unit commitment decisions from market participants to the system operator) would be suitable in the NEM in order to manage reliability outcomes since it would impose large costs on the market for little benefit – it would not be in the long-term interests of consumers. Further a US-style ahead market may not necessarily improve system security outcomes or reduce the cost of interventions - with or without an ahead-market, the potential benefits can only accrue if an explicit value is placed on the required system security services.

37 As noted below, AEMO and the AEMC will continue to work together on identifying potential deficiencies with the current arrangements – particularly in relation to security issues in South Australia. Overall, the Commission considers that a US-style ahead market is unlikely to provide sufficient benefits to the NEM in the short- or medium-term.

38 It is also worth noting that the Commission considered this Finkel recommendation in the context of the proposed Guarantee. The Guarantee is intended to integrate energy and climate change policy instruments in the NEM to provide investors with the certainty they need to make long-term investments, that are linked to physical needs of the system. This further decreases the case or need for a US-style day-ahead market.

39 In contrast, there may be benefits associated with facilitating shorter-term trading in the NEM i.e. a more European-style arrangement. These benefits include providing market participants with more options to manage price risk and more price certainty. A benefit of increased price certainty is that it may facilitate more demand response in the wholesale market. As noted above, it is recommended that AEMO undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market to allow participant-to-participant trading of financial contracts closer to real time.

40 SA Market Issues

41 In the Directions Paper, the Commission noted that AEMO was in the process of identifying the existing ahead features of the NEM that may require change and compiling evidence of the deficiencies that it considers need to be addressed, either through targeted improvements to existing arrangements or through a centrally facilitated ahead market design. This is being drawn from the South Australian experience.

42 Since that time, AEMO have progressed their work and presented some initial views to our technical working group on issues they are observing in operating the South Australian market. AEMO has observed that:

- South Australia's network is experiencing low system strength, inertia and higher reliability risks as synchronous generation has been displaced by renewable energy.
- It is currently intervening frequently in South Australia by directing synchronous generators to stay on to provide system strength. There are concerns that in the near future AEMO might need to frequently direct plant for reliability as well.
- AEMO, via the direction process, is intervening regularly in South Australia. The direction process can cause disruption to generators' maintenance schedule, which could reduce their performance quality and reliability in the long term. Having a formal market mechanism to provide the desired outcome could potentially lead to both operational and long-term efficiency gain. For these reasons AEMO have used this as a case study for their work.

43 To date, given the system security issues of low system strength are manifesting in real-time outcomes for the SA network, AEMO has focused on identifying and exploring these issues. This has included summarising current technical issues with operating the transmission network in South Australia, identifying what was involved in intervention events, investigating the appropriate strategies to manage those issues, and evaluating the costs and risks that may emerge from those strategies.

44 These issues are occurring in the absence of the full implementation of the Commission's minimum requirement system strength levels framework. The Commission understands infrastructure will be built to meet these minimum levels within 1-2 years. Prior to this implementation, maintaining system strength is achieved through directions by AEMO. The increased level of directions are translating to reliability issues in an operational timeframe as well as potentially translating into market outcomes which could undermine investment in reliability in the longer-term.

45 The AEMC looks forward to continuing to work with AEMO to investigate the issues being observed and consider the changes to the regulatory and market arrangements that may be necessary in both the short and then longer term that are effective and least cost and, to the extent relevant, in other jurisdictions. We intend to work together with AEMO to consider these issues by the end of 2018.

46 Dispatchability, flexibility and ramping

47 The Commission has also undertaken work on the historical value of dispatchability, flexibility and ramping in the spot market. Ramping, and in particular ramping availability, is a reference to the availability of generation or scheduled load to be dispatched in response to changes in supply and demand in a timely manner. This analysis indicates that:

1. The spot and contract markets currently provide incentives sufficient for the efficient provision of dispatchable and flexible generation and load (both necessary for adequate ramping capability), in both operational and investment timescales.
2. Ramping capability in the NEM is sufficient now and in the immediate future.

48 However, the market is in transition and we need to consider whether these conclusions will continue to apply given the transition that is underway. The Commission will build on the work undertaken in the Integrated System Plan, and seek to identify if the current market processes will continue to deliver future ramping requirements for the NEM by using South Australia as a case study.

49 Self-forecasting

50 The Commission has also considered whether self-forecasting by wind and solar generation operators could improve forecast accuracy. Improved accuracy would allow market participants and the system operator to make more efficient operational decisions, promoting reliability outcomes in the NEM.

51 AEMO and ARENA are conducting a trial whereby operators of some utility-scale wind and solar generation are able to provide a forecast of their expected output for the upcoming dispatch interval.

RECOMMENDATION	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
ARENA is encouraged to continue to develop trials for projects that explore the potential for forecast improvements in the hours ahead of dispatch, and to share the learnings of these projects in a timely manner through existing knowledge sharing arrangements, including with the Commission.	AEMC will stay involved in ARENA's processes and keep a watching briefing on the progression of the trials in order to be able to be across these issues if rule changes are submitted on this.
AEMO should consider providing the functionality for non-scheduled generators to participate in the existing trial that is available to semi-scheduled generators. AEMO should also seek to identify an appropriate regulatory arrangement to govern the provision of self-forecasts from all generators involved in the trial.	AEMO should consider this through ARENA's trials and subject to the outcomes of the trials, submit rule change requests to the Commission to embed the functionality for self-forecasting in the regulatory arrangements on an enduring basis.

Interventions

52 In operating the power system AEMO is expected to try to avoid any unserved energy (i.e. load shedding), including by using interventions available to it, if necessary.

53 Intervention mechanisms are an acknowledged and important feature of the market design. Given the changes in the generation mix over the past years and the increasing challenges this has created for the system operator, the use of interventions has increased relative to the past. This has increased the spotlight on them - for their suitability, their cost and the frequency of their application and use. Intervention mechanisms are being applied in a range

of scenarios to address a range of problems.

54 To understand the reasons for the market intervention and identify any 'lessons learnt' for the NEM, the use of interventions needs to be examined in the context in which they are needed. It is important to understand the circumstances involved with each intervention before considering whether the increased use of intervention mechanisms are indicative of broader problems; some interventions may not be suited to all power system operational problems.

55 These mechanisms are not without cost. For example, for the 2017/18 summer AEMO estimates that the total cost of having the Reliability and Emergency Reserve Trader (RERT) on call and activated twice (168.5MW activated in total) was $51.26 million. This cost includes availability payments (i.e. payments for out-of-market generation/demand response being available regardless of whether or not an event occurs as well as other payments, including activation payments). The costs of interventions are ultimately borne by consumers in the regions that required the intervention.

56 Because of the inherent interference with normal market functioning and the consequent consumer cost impacts, the regulatory arrangements limit the use of intervention mechanisms. These constraints are appropriate since it will not always be possible to have no unserved energy - to do so would substantially increase consumer costs. For example, the RERT may only be used if AEMO identifies a breach or potential breach of the reliability standard, or for power system security reasons. There may also be times when AEMO has no choice operationally and/or legally but to require involuntary load shedding to maintain the secure power system. As established in the NER power system security must always take precedence over reliability – the power system is only allowed to operate in an insecure state (i.e. operate outside the established technical limits) for 30 minutes, so as not to risk uncontrolled power system outcomes following a credible contingency. AEMO is obliged to take all actions available to it including instructing load shedding to achieve a secure power system within 30 minutes.

57 The Finkel Panel recommendation made to the Commission, regarding assessing the need for a strategic reserve to enhance or replace the RERT (recommendation 3.4), is being considered through the *Enhancement to the Reliability and Emergency Reserve Trader* (RERT) rule change ("enhanced RERT"), which was submitted by AEMO. The Commission is exploring the potential improvements to the RERT that are within the scope of that rule change request, through the rule change process rather than through this review. This includes the appropriateness of the reliability standard. We published a consultation paper on 21 June 2018 and are seeking stakeholder input (closing 26 July 2018).

58 It will be important to consider the other intervention mechanisms (instructions and directions) alongside our consideration of the RERT. The order in which the three interventions mechanisms are used must deliver the lowest cost outcome for consumers. The NER provide some guidance on this issue but considering the interventions framework as a whole would allow the best outcomes for consumers to be considered holistically.

59 As a result, the Commission will consider the interventions framework in parallel with the enhanced RERT rule change. We will examine intervention mechanisms and the rules

underpinning them from a broad framework perspective. In addition, we will also examine the intervention pricing and compensation mechanisms associated with interventions. These frameworks have come under increasing attention with the increased use of interventions and may be distorting market outcomes in the NEM.

RECOMMENDATIONS	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
The AEMC will consider the NEM intervention mechanisms of directions and instructions, including the rules governing them, from the perspective of how interventions occur and operate as a suite of mechanisms (including in relation to the RERT), in parallel with the enhanced RERT rule change. In this workstream, the AEMC will also build on the work that has been done by AEMO through the Intervention Pricing Working Group and review the current intervention pricing and compensation framework to make sure that it is sufficiently nuanced to respond efficiently to the variety of contexts in which AEMO intervention events occur.	A directions paper on the NEM intervention mechanisms of directions and instructions will be published alongside the draft determination for the *Enhancement to the RERT* ("enhanced RERT") rule change request in October 2018. This is ahead of a final report on this intervention workstream being published alongside the final determination for enhanced RERT, currently scheduled for December 2018.

60 In addition, while it is not suggested that commercially sensitive information should be made public, greater transparency regarding the directions compensation process is appropriate, particularly given that consumers pay for compensation costs, and noting the increase in the use of directions in South Australia. This would be particularly useful in considering whether the current compensation framework is incentivising bidding practices that are not efficient, at the expense of consumers. It could also inform deliberations as to whether the current approach to intervention pricing is appropriate in situations where the intervention relates to a service (system strength or inertia) that is not traded in the market.

RECOMMENDATION	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
AEMO to consider how to increase the level of transparency surrounding AEMO intervention events (directions and RERT activation) and resulting compensation payments. This could be achieved through changes to processes adopted by AEMO and	AEMO should consider this by October 2018 and report on the outcomes of this piece of work through a submission to the AEMC's work on the mechanisms.

RECOMMENDATION	HOW THE RECOMMENDATION WILL BE IMPLEMENTED OR FURTHER PROGRESSED
their independent expert consultants, and may not necessitate changes to the NER.	

61 In addition, the Finkel Panel recommended that the AEMC and AEMO consider the need for a strategic reserve in the NEM. AEMO has submitted a rule change request to the AEMC to amend the NER in regards to enhancing the RERT. The Commission considers that a safety net mechanism such as the RERT is an important feature of the NEM and so is considering the ways to make this the most effective through this rule change.

FINDING	HOW THE FINDING WILL BE IMPLEMENTED OR FURTHER PROGRESSED
AEMC will consider the appropriate arrangements for the RERT (i.e. strategic reserve) in the NEM through AEMO's *Enhancement to the RERT* rule change request.	We published a consultation paper on 21 June 2018 and are seeking stakeholder input (closing 26 July 2018). A draft determination is due in October 2018.

Conclusions and next steps for the work program

62 The Commission has concluded this stage of this Review and made a number of recommendations to improve the existing reliability frameworks in the NEM, as detailed above. In particular, this report concludes the Commission's work relevant to the Finkel Review recommendations which were made to the Commission. The Commission was asked to complete these recommendations by mid 2018. The table below summarises our findings.

FINKEL PANEL RECOMMENDATION	OUTCOME
Finkel recommendation 3.4 Assessing the suitability of a day-ahead market.	The Commission has concluded that a US-style day-ahead market would not be suitable in the NEM in order to manage reliability outcomes. Instead, the Commission considers that there would be benefits to the introduction of a voluntary, contract-based short-term forward market, particularly for demand response.
Finkel recommendation 6.7 Development of a mechanism to facilitate wholesale demand response.	The Commission is recommending a package that seeks to remove barriers to demand response and provide a range of additional

FINKEL PANEL RECOMMENDATION	OUTCOME
	tools for parties to undertake wholesale demand response.
Finkel recommendation 3.4 Assessing the need for a strategic reserve to enhance or replace the RERT.	This is now being considered through the enhanced RERT rule change process.

63 The Commission has also identified other areas of the framework that should be investigated further in order to identify improvements. The Commission will progress these in the coming months.

64 The next steps for the work program include:

1. South Australian workstream - AEMO and the AEMC will consider further the issues that AEMO has been observing in operating the South Australian market, including:
    a. How the issues can be addressed in the short-term and what the implications of these issues are for the current reliability and security frameworks in the longer-term.
    b. Building on the existing analysis we have undertaken of current ramping availability and work undertaken by AEMO in the Integrated System Plan to consider what future ramping needs of the NEM may be.

    In order to progress this workstream we intend to publish a directions paper relevant to the issues AEMO has been observing in operating the South Australian market shortly. This will be ahead of AEMO developing rule changes to address the issues identified to be submitted to the Commission.
2. Interventions workstream - We will holistically review the NEM intervention mechanisms of directions and instructions, including the rules governing them, from the perspective of how interventions occur and operate as a suite of mechanisms (including in relation to the RERT), in regards to both reliability and system security. We will conduct this workstream in parallel with the enhanced RERT rule change request. This means publishing a directions paper on this workstream alongside the draft determination for the enhanced RERT rule change request in October 2018, and a final report alongside the final determination in December 2018.
3. Short-term forward market workstream - We will work collaboratively with AEMO in developing a voluntary, contracts-based short-term forward market to allow participant to participant trading of financial contracts. The intent will be for AEMO to submit this to us in a rule change request by end 2018.

65 This work is separate to the rule change requests identified above. These, and any other rule change requests related to the above will be progressed concurrently and in coordination with other parts of our reliability work program.

66 A progress update on the Commission's reliability work program will be provided to the COAG Energy Council prior to its meeting in December 2018.

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APPENDICES

TABLES

FIGURES

1 INTRODUCTION

On 11 July 2017, the Australian Energy Market Commission (AEMC or Commission) commenced a Review into the market and regulatory frameworks necessary to support the reliability of the electricity system within the NEM.[1] This Review also includes consideration of three recommendations that were subsequently directed to the AEMC from the *Independent Review into the Future Security of the National Electricity Market* (Finkel Panel review) that relate to reliability.

1.1 Purpose of the Review

Over the 12 months preceding the commencement of the Review, there were a number of events (such as load shedding on low reserve[2] days) that put the spotlight on reliability in the National Electricity Market (NEM). In commencing the Review, the Commission considered that it was timely to assess whether the existing market and regulatory reliability frameworks are still appropriate given the changing generation mix with an increased penetration of variable renewable generation, batteries and distributed energy resources, as well as greater opportunities for demand-side participation.

Since the Review commenced, reliability has continued to be at the forefront of policy discussion.

The Energy Security Board has proposed a National Energy Guarantee, which seeks to balance affordability, reliability and an emissions objective. It would require retailers to:

- contract with or invest in capacity such as generators or demand response in the event of a material expected reliability gap and
- source electricity with average emissions below an agreed level.

In addition, State and Commonwealth governments are progressing with new generation and storage projects (both chemical batteries as well as pumped hydro), the most notable examples being the proposed Snowy Hydro 2.0[3] and South Australia's 100 MW battery.[4]

Table 1.1 provides a timeline for this Review.

Table 1.1: Review timeline

ITEM	DATE
Publication of issues paper	22 August 2017
Publication of interim report	19 December 2017

1 The Review was initiated by the AEMC under section 45 of the National Electricity Law (NEL). The regulatory framework refers to the NEL and National Electricity Rules.

2 Reserve levels are a key concept in the NEM, and can broadly be considered to be the balance of expected supply over demand in the market.

3 SnowyHydro, Snowy 2.0, accessed at: http://www.snowyhydro.com.au/our-scheme/snowy20, 24 October 2017.

4 Government of South Australia, Battery storage and renewable technology fund, accessed at http://ourenergyplan.sa.gov.au/battery.html, 24 October 2017.

ITEM	DATE
Publication of directions paper	17 April 2018
Publication of final report	26 July 2018

The next steps for this review are discussed further below in section 1.7.

1.2 Purpose of the final report

This report concludes the four major work streams identified in the Review and sets out a number of recommendations to the COAG Energy Council regarding the 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.[5]

This report makes recommendations with respect to the four key elements of the reliability framework in the NEM:

- information provision
- the wholesale market including:
  - integrating the demand-side into the wholesale market
  - improving outcomes in the wholesale market
- intervention mechanisms.

The report also sets out the Commission's conclusions on the following **three Finkel Panel recommendations** set out above:

- assessing the suitability of a day-ahead market (Finkel recommendation 3.4)
- development of a mechanism to facilitate wholesale demand response (Finkel recommendation 6.7)
- assessing the need for a strategic reserve to enhance or replace the RERT (Finkel recommendation 3.4).

In relation to the recommendation of assessing the **suitability of a day-ahead market**, the Commission does not consider that a US-style ahead market (that would change unit commitment decisions from market participants to the system operator) would be suitable in the NEM in order to manage reliability outcomes since it would impose large costs on the market for little benefit – it would not be in the long-term interests of consumers. For more information on this, see section 5.3.

In relation to the Finkel Panel recommendation to **develop a mechanism to facilitate wholesale demand response,** the Commission considers this be done to provide for multiple forms of demand response. The Commission recommends the following approach to implementation of the mechanism:

5 In addition, our *Frequency control frameworks review* has recently made a series of draft recommendations that aim to address risks to power system security (in this case, frequency performance) as the electricity sector changes. See: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

- a voluntary, contracts-based short-term forward market be implemented
- allowing demand response aggregators providers to be recognised on equal footing with generators in the wholesale market
- consumers should be allowed to engage multiple retailers / aggregators at the same connection point, i.e. multiple trading relationships.

There Commission recommends that these recommendations should be supported through trials. For more information on this, including the work of a number of stakeholders in developing models and undertaking trials, see section 4.1.

The third Finkel Panel recommendation, **assessing the need for a strategic reserve** to enhance or replace the RERT, is being considered through the *Enhancement to the Reliability and Emergency Reserve Trader* (RERT) rule change process.[6]

The Review originally included the Finkel Panel recommendation of developing a generator reliability obligation. However, the reliability requirement proposed by the Energy Security Board as part of the National Energy Guarantee is intended to address the same underlying issues as the generator reliability obligation. Details of the Guarantee are continuing to be developed by the Energy Security Board and will be considered by the COAG Energy Council at its August 2018 meeting.

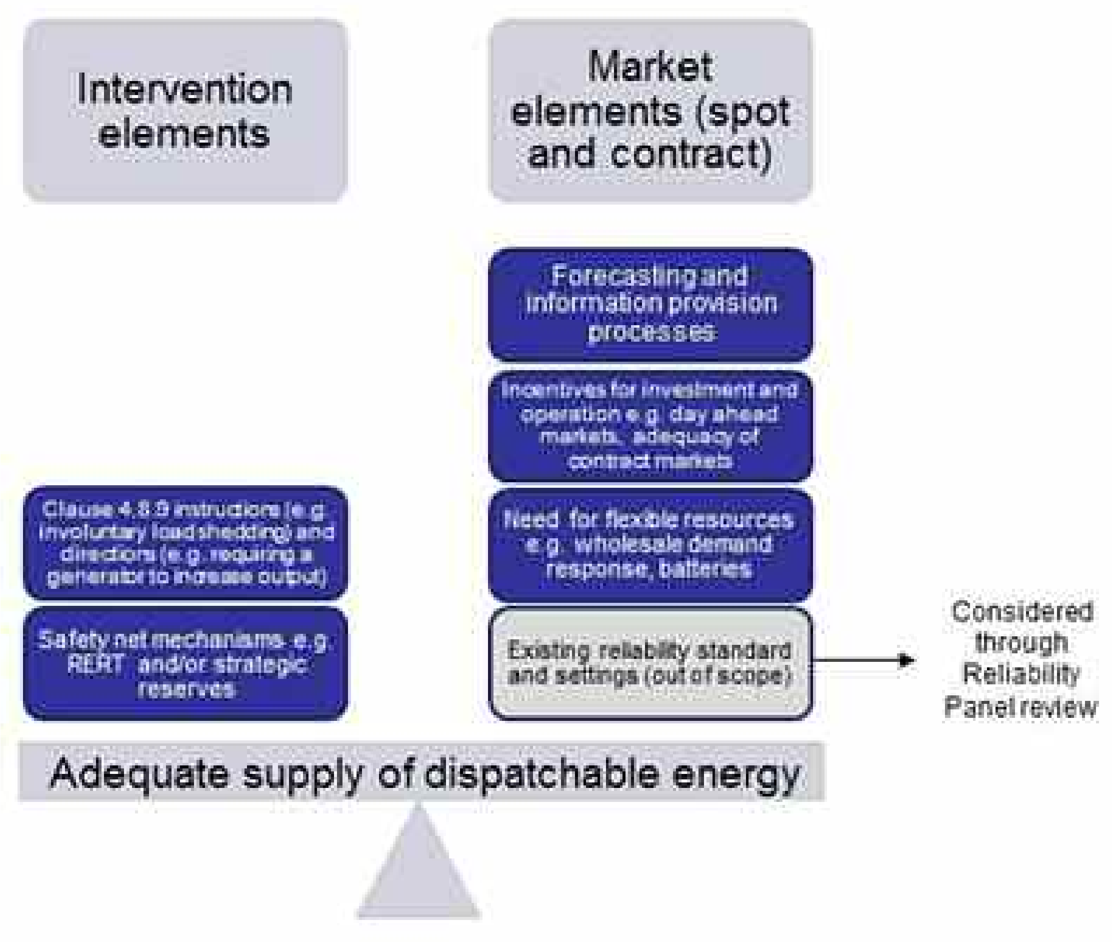
1.3 Project scope

This Review has undertaken a holistic examination of the existing reliability framework. This framework includes both longer-term aspects such as the appropriate pattern of investment in new resources and retirement of existing resources, as well as shorter-term operational aspects such as making sure an adequate supply is available at a particular point in time; all while balancing the cost of any intervention measures. This Review looks has done this from both the supply-side (generation) as well as the demand-side (demand response).

The scope of the Review is shown in Figure 1.1 below.

6 See: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

Figure 1.1: Scope of the Review



The Review has also taken into account relevant AEMO workstreams, such as their work on issues in South Australia as well as trials that they are undertaking with Australian Renewable Energy Agency (ARENA) such as their self-forecasting project.[7] It will take account of any other trials that ARENA and AEMO undertake through their memorandum of understanding. In this regard, the ongoing work of AEMO and ARENA will inform the implementation of the recommendations made in this report.

There are a number of aspects that were out of scope for this Review:

- reliability of transmission and distribution networks since each state and territory government retains control over how transmission and distribution reliability is regulated and the level of reliability that must be provided

7 Discussed in chapter 5.

- security of the power system, since this is being addressed through the AEMC's comprehensive system security work program detailed below
- the existing reliability standard and settings, since they were recently considered in the Reliability Panel's *Reliability standard and settings* review. The Reliability Panel published a final report in April 2018.[8] The appropriateness of the reliability standard is being considered through AEMO's *Enhancement to the RERT* rule change request that the Commission is currently considering.

1.4 Assessment framework

The overarching objective guiding the Commission's approach to this Review is the National Electricity Objective. The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the National Electricity Objective. Similarly, with any related rule changes, the Commission must consider whether the proposed rules promote the National Electricity Objective. The National Electricity Objective 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."

In developing the recommendations and findings in this report, the Commission has had regard to a number of principles. These are:

- **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. Placing inappropriate risks on consumers, who are not best placed to manage these risks is likely result in higher prices while risk to market participants will only be passed on to consumers in terms of higher prices where competition permits. Under arrangements where investment and operational decisions are made by a single entity such as a planner or system operator, risks are more likely to be borne by consumers. This is because this single entity does not have sufficient commercial incentive to minimise costs as they are likely passed straight through, resulting in inefficiently high costs for consumers than they would be if the costs associated with decisions were incurred by market participants operating in competitive environments. Solutions that allocate risks to market participants, such as commercial businesses, who are better able to manage them are preferred, where practicable.
- **Efficient investment in, and operation of, energy resources to promote a reliable supply:** Any framework for reliability should result in efficient investment in,

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

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. The reliability framework should also seek to minimise distortions in order to promote the effective functioning of the market.

- **Technology neutral:** Regulatory arrangements should be designed to take into account the full range of potential market and network solutions, as well as taking account of all possible technologies that could provide such solutions (e.g. generation or demand-side). They should not be targeted at a particular technology or business model, 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.
- **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 action should be proportional to the issue identified, for example long-term changes should not be made to address a transitory issue. Similarly, NEM-wide solutions should not be used to address an issue in one jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions.
- **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.

1.5 Stakeholder consultation

1.5.1 Submissions to the Review

The Commission received a significant number of submissions from a wide range of stakeholders:

- 18 submissions to the issues paper (September 2017)
- 31 submissions to the interim report (February 2018)
- 34 submissions to the directions paper (May 2018).

Stakeholders generally expressed support for market-based mechanisms, and stated that interventions should only be used as a last resort.[9] As previously mentioned, stakeholders also overwhelmingly recognised the lack of a clear, consistent and integrated environmental and energy policy as a key aspect affecting reliability.[10] Stakeholders also highlighted the interaction between the Guarantee and this Review.[11]

9 See for example the following submissions to the interim report: AGL, Energy Networks Australia, Hydro Tasmania, Flow Power.

10 Sixteen of the eighteen submissions to the issues paper recognised this.

11 See for example the following submissions to the directions paper: EnergyAustralia, Hydro Tasmania, Snowy Hydro, Aurora Energy and the Australia Institute

1.5.2 Reference group and technical 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) was established by the AEMC to provide high-level input on related reliability matters. The reference group has met three times (August and November 2017; March 2018) and input from this group has been incorporated into this paper.

The AEMC has also established a technical working group to provide technical advice, and to assist with the development of recommendations for this Review. The group comprises representatives from AEMO, the AER, ARENA, consumer groups, large energy users, conventional generators, renewable generators, retailers, demand response providers, and transmission and distribution network service providers. The technical working group has met three times:

- in November 2017, with the discussion focussing on initial views with respect to the contract market, key concepts and demand response
- in February 2018, with the discussion focussing on forecasting, demand response and day-ahead markets
- in June 2018, with the discussion focussing on forecasting, demand response, dispatchability and flexibility and interventions.

Comments and feedback from the technical working group have been incorporated into this report.

1.6 Related work and next steps

1.6.1 AEMC and Reliability Panel projects

This Review forms part of a broader reliability work program being undertaken by the AEMC and the Reliability Panel. The key projects are discussed in more detail in chapter 2.

1.6.2 National Energy Guarantee

The Energy Security Board's initial advice on the Guarantee broadly and conceptually set out changes needed to the NEM and its legislative framework such that:

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

The Energy Security Board published a draft detailed design of the Guarantee in June 2018 for consultation. The COAG Energy Council is expected to make a final decision on the Guarantee in August 2018.

1.6.3 Next steps

The Commission has concluded this stage of the Review and made a number of recommendations to improve the existing reliability frameworks in the NEM, as detailed above. In particular, this report concludes the Commission's work relevant to the Finkel Review recommendations referred to above.

However, the Commission has also identified areas of the framework that should be investigated further in order to identify improvements. The Commission intends on progressing these in the coming months. This allows us to continue to consider these issues as part of a holistic review considering the totality of the reliability frameworks given the interlinked nature of these issues.

The next steps for the work program include:

1. South Australian workstream - AEMO and the AEMC will consider further the issues that AEMO has been observing in operating the South Australian market, including:
    a. How the issues can be addressed in the short-term and what the implications of these issues are for the current reliability and security frameworks in the longer-term.
    b. Building on the existing analysis we have undertaken of current ramping availability and work undertaken by AEMO in the Integrated System Plan to consider what future ramping needs of the NEM may be.

    In order to progress this workstream we intend to publish a directions paper relevant to the issues AEMO has been observing in operating the South Australian market shortly. This will be ahead of AEMO developing rule changes to address the issues identified to be submitted to the Commission.

2. Interventions workstream - We will holistically review the NEM intervention mechanisms of directions and instructions, including the rules governing them, from the perspective of how interventions occur and operate as a suite of mechanisms (including in relation to the RERT), in regards to both reliability and system security. We will conduct this workstream in parallel with the enhanced RERT rule change request. This means publishing a directions paper on this workstream alongside the draft determination for the enhanced RERT rule change request in October 2018, and a final report alongside the final determination in December 2018.
3. Short-term forward market work stream - We will work collaboratively with AEMO in developing a voluntary, contracts-based short-term forward market to allow participant to participant trading of financial contracts. The intent will be for AEMO to submit this to us in a rule change request by end 2018.

This work is separate to the rule change requests identified above. These, and any other rule change requests related to the above will be progressed concurrently and in coordination with other parts of our reliability work program.

A progress update on the Commission's reliability work program will be provided to the COAG Energy Council prior to its meeting in December 2018.

1.7 Structure of this report

The remainder of this report is structured as follows:

- chapter 2 sets out the context for this Review
- chapter 3 discusses information provision
- chapter 4 examines options to integrate demand into the wholesale market
- chapter 5 sets out options for improving wholesale market outcomes
- chapter 6 provides an update on the intervention framework
- appendix A provides our detailed analysis of options to facilitate demand response in the wholesale market
- appendix B sets out our analysis of dispatchability, flexibility and ramping in the NEM
- appendix C provided an update on contract market data
- appendix D details our consideration of the suitability of a day-ahead market in the NEM
- appendix E provides an update on the concept of unserved energy in the NEM.

2 THE NEM: FUNDAMENTAL DESIGN PRINCIPLES

2.1 Reliability and security

2.1.1 What is reliability?

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

- efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of capacity to meet demand plus a sufficient level of reserves
- a reliable transmission network
- a reliable distribution network, as well as
- the system being in a secure operating state, that is, one where the power system is in, or will return to, the NER requirement of a satisfactory operating state within 30 minutes.[12]

This Review focusses on the first element of a reliable power system.[13]

2.1.2 How is reliability different to security?

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 mostly caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits, such as voltage and frequency.

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

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

Following a contingency event or significant change in power system conditions, AEMO must use its reasonable endeavours to return the power system to a secure operating state within 30 minutes.[14] AEMO may authorise a person to do any of the things contemplated by section 116 of the NEL if AEMO is satisfied that it is necessary to do so for reasons of public safety or the security of the electricity system.

However, the two concepts are closely related operationally and it is not always simple to separate them. A reliable power system will also be a secure power system (indeed, as set

12 The "satisfactory operating state" is a defined term under the NER, which is set out in clause 4.2.2.
13 The reliability standard, which is contained within the NER, assists with the first element.
14 NER clause 4.2.6(b).

out above a secure power system is one element of having a reliable system). However, the converse is not necessarily true; a power system can be secure even when it is not reliable. One of the ways in which AEMO can do this is to undertake involuntary load shedding, potentially compromising reliability, in order to return the power system to a secure operating state.

Reliability issues occur where the demand-supply balance in the system is tight, typically at times of peak demand for electricity, generally on very hot days. For example, when the RERT was exercised in January 2018, it was in the middle of the afternoon with the temperature exceeding 40 degrees Celsius in Victoria.[15] In contrast, **security** issues can arise at any time - and at present, more often than not tend to occur at off-peak times, when there are low demand conditions.[16]

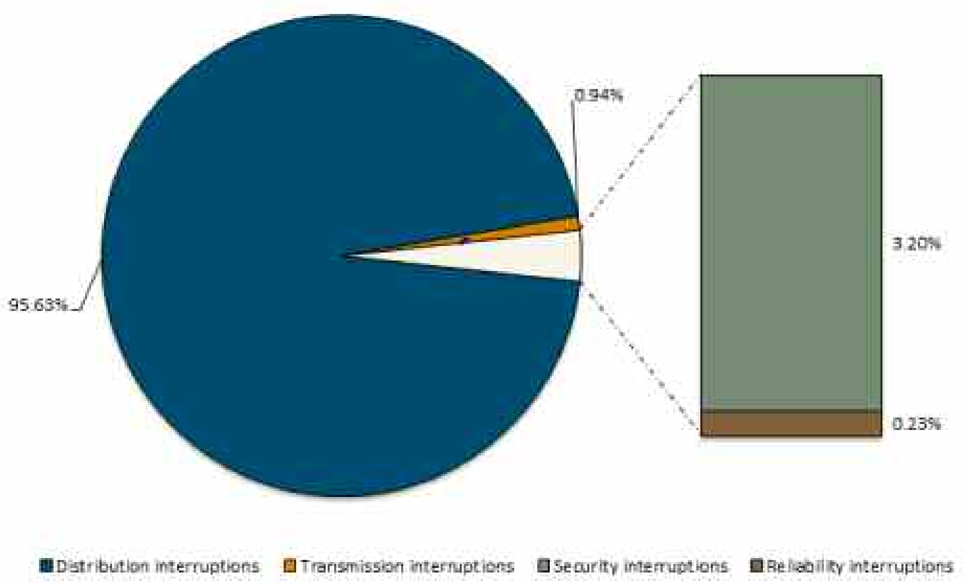
BOX 1: SUPPLY INTERRUPTIONS

Consistent with the various elements of a reliable power system described above, there are a number of causes of supply interruptions to customers: reliability (e.g. having insufficient generation to meet demand); security (e.g. load being shed to manage frequency across the system); or network (e.g. a particular line being out driving a network outage). This Review is concerned with reliability-related supply interruptions, which as shown in the brown area of the graph below only account for a small fraction of supply interruptions to consumers in the NEM.

15 AEMO activated reserve contracts to maintain the power system in a reliable operating state. The contracts were activated at 14:00 AEST on 19/01/2018. See: market notice 60843, 19 January 2018, 13:43, market intervention

16 For example, on 2 December 2017, AEMO directed on a participant in South Australia to maintain the power system in a secure operating state, with the direction issued at 00:00. The direction was issued at 00:00 02/12/2017, with effect from 01:00 hrs 02/12/2017. See: market notice 60176, 2 December 2017, 0:02, market intervention.

Figure 2.1: **Sources of supply interruptions in the NEM: 2007-08 to 2016-17**



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

Figure 2.1 shows an indicative analysis of sources of supply interruptions in the NEM over the period 2007-08 to 2016-17.

This shows that supply interruptions that stem from reliability issues (not having enough supply to meet demand), are relatively limited in number. Over the period, only about 0.23 per cent of total supply interruptions (in terms of GWh) was the result of inadequacy of supply, noting that this is well below the reliability standard. This is much smaller than the amount of security interruptions that have occurred: over the past 10 years there have been 3.20 per cent (nearly 10 times more) supply interruptions for security. The vast majority of supply interruptions were network interruptions, specifically from the distribution network.

Note: The reliability standard is unserved energy of no more than 0.002 per cent of demand - NER clause 3.9.3C. The amount of unserved energy associated with the reliability interruptions in the chart is well below 0.002 per cent of demand. The only year when there was unserved energy in excess of the standard was in 2008-09.

The definitions of 'system security' and 'reliability' that are used in Australia were developed prior to the commencement of the NEM. When the NEM was established, the roles and responsibilities of participants were developed to be consistent with, and reinforcing of, these definitions. Specifically, 'reliability' issues are typically resolved by the market, responding to information provided by the system operator;[17] whereas 'security' issues are operationally directly managed by the system operator. Therefore, the analysis of reliability and security issues in the NEM needs to be conducted in this context.

17 However, AEMO may intervene for reliability purposes in instances where the market has failed to resolve reliability issues, using the measures available to it under the NER.

Under current market and regulatory frameworks, the obligations in relation to the delivery of reliability and security, and the tools available to AEMO to maintain a 'secure operating state'[18] and a 'reliable operating state'[19] are therefore different and tailored to meet either the security or reliability outcomes necessary for the power system within the above context.

2.1.3 How has the NEM performed on both security and reliability?

Every year, the Reliability Panel reviews the performance of the NEM in terms of reliability, security and safety in its Annual Market Performance Review report. Of relevance here is the reliability and security of the NEM in the most recent report.

During 2016/17, the security performance of the NEM was mixed. In 2016/17 there were 11 instances of the system being outside its secure (target) limits for greater than 30 minutes. This is an increase on 2015/16 when there were seven instances, and on 2014/15 with just four instances. Some major security events occurred in 2016/17, chiefly, the South Australian black system event on 28 September 2016.

Against the reliability standard in the NER, the NEM performed well for the 2016/17 timeframe. In 2016/17, at a wholesale level, there was only 0.00036 per cent unserved energy recorded from one reliability event that occurred in South Australia on 8 February 2017. This event was characterised by extreme temperatures that led to high demand conditions and coincided with factors including outages of thermal generation and inaccurate forecasts.[20]

The amount of unserved energy in 2016/17 is well within the NEM reliability standard (an expectation that no more than 0.002 per cent of demand for energy will be unmet in any region of the NEM). There was no other unserved energy recorded due to wholesale reliability events for any other region in the NEM. Importantly, AEMO is forecasting that the reliability standard will also be met over the next two years through the MT PASA, in particular that projected unserved energy is within the reliability standard (i.e. 002 per cent expected unserved energy for a financial year).

The most recent Energy Consumer Sentiment survey run by Energy Consumers Australia has some useful data that is relevant to these observations. It found that consumers are broadly satisfied with the reliability of their electricity services. Specifically, between 60 and 70 per cent of consumers say they are satisfied in every state and territory in the NEM. However, the proportion of consumers expressing confidence that the market will deliver increased reliability in the future had fallen since the last time the survey was undertaken - to between 34 to 46 per cent.[21] Consumers say that their primary concern is affordability, suggesting that while investment is needed, care should be taken not to spend more than necessary on new generation or upgrading or maintaining the networks.[22]

18 See clause 4.2.4 and Chapter 10 of the NER for a definition.

19 See clause 4.2.7 and Chapter 10 of the NER for a definition.

20 AEMO, System Event Report South Australia, 8 February 2017, 15 February 2017.

21 See: http://energyconsumersaustralia.com.au/wp-content/uploads/Energy-Consumer-Sentiment-Sur vey-December-2017.pdf

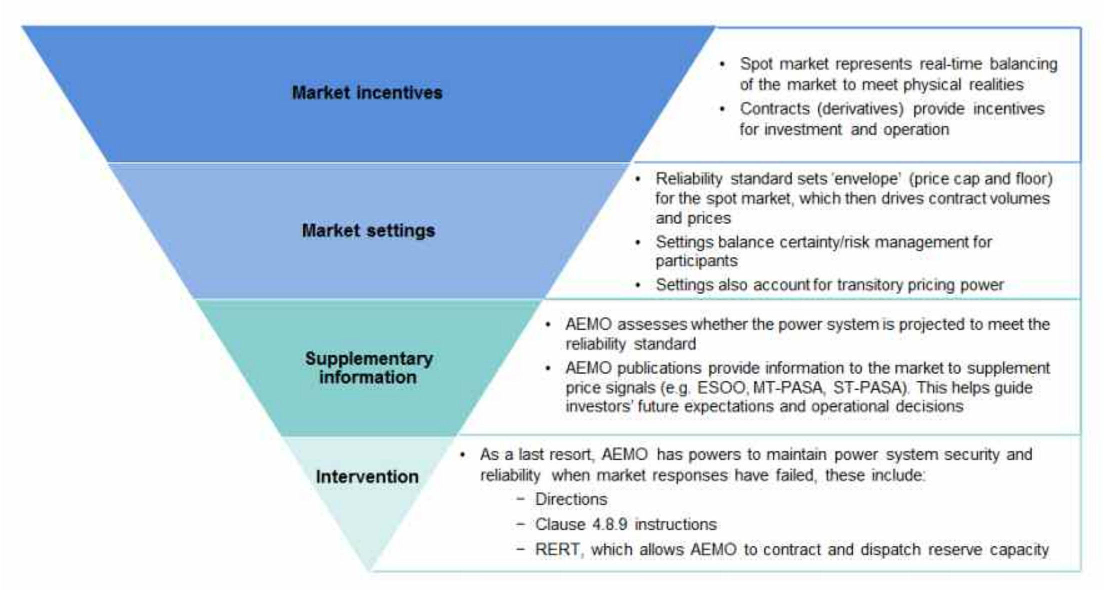
22 See: http://energyconsumersaustralia.com.au/news/new-data-attitudes-energy-households-small-busi nesses-demands-focus-affordability/

The Commission has recently made a rule to make the AER responsible for calculating and updating values of customer reliability. The AER is required to publish the first VCRs by no later than 31 December 2019. The VCR survey results will help to inform consumer views on the reliability trade-off in the future.

2.2 Current reliability framework

Figure 2.2 provides a summary of the existing reliability framework, including the reliability standard, the reliability settings and AEMO's intervention mechanisms. Reliability in the NEM is largely driven through market participants responding to financial incentives and information provided about the need for resources.

Figure 2.2: Current framework with escalating series of interventions



Consistent with the National Electricity Objective, the reliability framework has been designed to balance two costs:

- Costs of reliability - Maintaining reliability involves costs. The higher the level of reliability, the more that investment in capacity (e.g. more generation, demand-side resources or network assets) and/or more stringent operating conditions is required, all which impose costs on parties. For example, having more generation being operated more stringently (i.e. having more generation being operated to meet a higher standard of reliability) creates higher per unit costs of electricity. These costs will be reflected in consumer prices.
- Costs of unserved energy - The alternative to providing energy, no matter the cost is not to supply the energy under certain conditions. That is to allow for an expected level of supply interruptions to consumers. This also has a cost - reflecting the customer's

willingness to pay for the reliable supply of electricity (this is known as the value of customer reliability). If a customer has their electricity supply interrupted, when they were willing to pay to consume electricity, they will face costs e.g. lost production if it is a business; or a colder / hotter home for residential customers with air conditioning.

A reliability framework therefore embodies a trade-off between the prices paid for electricity and the cost of not having energy when it is needed. 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 supplying energy would exceed the value placed on it by consumers.

Market participants operating in a competitive environment, as well as the system operator, all have a role in facilitating reliable outcomes in the NEM. Outcomes in the NEM are driven by a number of individual decisions by parties who bear the consequences of their decisions being wrong, and so face incentives to mitigate these risks and improve outcomes in the future. Investment and operation of generation and demand-side assets is market-driven and takes into account expectations and information that is provided on future demand and supply.

This is in contrast to a centrally-planned system where one party, the system operator, makes decisions based on the information provided to it by market participants. In such a system, consumers will bear the risks and costs associated with the system operator's decisions. Since the system operator has no commercial incentive and so it is unlikely that such a system will lead to the most efficient outcome where costs to consumers are minimised since they do not have as strong incentives as market participants to learn over time and mitigate against future risks.

Therefore, the role of information and incentives being placed on these market participants is important so that they can respond to this in making investment and operational decisions. Market participants who operate in a competition environment are better placed to make these decisions in response to this information as they have incentives to do so since if they do not, they will bear financial consequences.

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 in the NEM. Market participants make investment and operational decisions based on these market signals. Prices in the spot and contract markets provide signals for adequate generation and demand-side resources to be built and dispatched, as well as information about the balance of supply and demand across different places and times.

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

This framework provides incentives for an efficient mix of technologies to be deployed - for example, expectations of highly volatile supply and demand conditions translate into expectations of highly volatile spot market prices. The degree of volatility affects the demand for and value of hedge contracts such as caps and swaps. In turn, this provides incentives for investment/retention of plant best able to capitalise on that volatility, such as peaking plant and storage solutions.

Spot market

The NEM's spot market is a gross pool design with mandatory participation. Generators sell, and market customers buy, all of their electricity through the spot market, which matches supply and demand (near) instantaneously, including an allowance for a sufficient quantity of reserves. Reserves in the NEM are represented by those generators that offer their availability into the wholesale market, but are not dispatched.

Scheduled and semi-scheduled generators and loads offer and bid into the market dispatch engine, operated by AEMO. Once these offers and bids are received, AEMO then forecasts the expected consumer demand for electricity in each region for each 5-minute dispatch interval. Then, the dispatch engine seeks to optimise outcomes by attempting to maximise the value of trade given the physical limitations of the power system. These physical limits are otherwise known as "constraints" which, for example, restrict how much electricity can flow over a particular piece of equipment i.e. keeping it within its technical capability.

The market settings - the reliability standard, the market price cap, cumulative price threshold, administered price cap and market floor price - are an integral part of the reliability framework. They limit the extent to which wholesale prices can rise and fall. They are set at a level so as not to interfere with the price signals needed for efficient investment and operation and are discussed further below.

Contract market

The contracts, or financial derivatives, market serves the following four purposes:

1. It provides a mechanism for retailers and generators to manage their exposure to spot prices, by allowing participants to trade uncertain and variable spot market prices for fixed prices[23] going forward.
2. On a short-term operational timescale (e.g. hourly), generators who have sold contracts are incentivised to be available when needed (i.e. when spot prices are high), in order to be dispatched to at least the volume of their contracts so earn revenues in the spot market to fund payouts on their contract positions. They are indifferent to the level of spot prices as the price they receive is determined by their contracts, provided they are dispatched. This incentive to 'turn up' is heightened during high price/tight demand-supply periods, which is precisely when the system most values the generator's output.

23 The price of hedging contracts reflects the balance of expectations as to the level and volatility of future wholesale spot price outcomes, that is, if average spot prices are expected to increase in the future, contract prices will follow, and vice versa. If this were not the case – and the price of hedges was out of line with expectations of future market prices – then profitable arbitrage opportunities would arise to close the gap.

3. It lowers the cost of financing investment in generation capacity, which lowers the cost of achieving and maintaining system reliability. Contracts provide generators a steadier stream of revenue compared to taking spot price exposure. This reduces the risks to parties providing funding to generators, such as debt and equity holders, that the value of their investments may not be recouped. This lowers the overall cost of capital required to finance the project and lowers the cost of the new generation capacity.
4. It underwrites retailers' fixed-price offers to end-consumers, such as households and small businesses. Like generators, retailers use the contract market to mitigate their exposure to the spot market. Contracts provide retailers with a consistent price for electricity, which in turn allows them to offer longer-term contracts, with stable prices, to their retail customers.

Alternatively, a retailer (generator) could invest in generation (retail), which is more commonly known as vertical integration.

2.2.2 Market settings

Reliability standard

The reliability standard is the maximum expected unserved energy (USE) in a region for a given financial year. In general terms, 'unserved energy' means the amount of customer demand that cannot be supplied within a region of the NEM due to a shortage of generation or interconnector capacity. Crucially, this is not set at zero per cent. The current reliability standard is 0.002 per cent expected unserved energy. In simple terms, the reliability standard requires there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of forecast total energy demand in a financial year is expected to be supplied.[24] When the reliability standard is set, it involves a trade-off between the prices paid for electricity and the cost of not having energy when it is needed: increasing levels of reliability involves increased costs.

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

Reliability settings

The reliability settings are closely linked to, and derived directly from, the 'reliability standard'. These form a price envelope for spot prices:

- Market price cap - The maximum price that a generator may bid during a dispatch interval is currently $14,500/MWh.[25] This limits market participants' exposure to

24 See definition of 'unserved energy' in Chapter 10 of the NER and clause 3.9.3C of the NER.
25 This is indexed annually by the consumer price index (CPI) by the AEMC.

temporary high prices, being the maximum bid and settlement price that can apply in the wholesale spot market. It is set at such a level that prices over the long-term should incentivise enough new investment in generation, as well as appropriate operational decisions, to achieve the reliability standard.

- Market floor price - The minimum price that a generator may bid during a dispatch interval is -$1,000/MWh. This limits the amount of money a generator can lose in a single half hour, preventing market instability.
- Cumulative price threshold - This limits market participants' financial exposure to prolonged high prices, by capping the market price (currently at $212,800/MWh) that can occur over seven consecutive days. As with other reliability settings, it is set at a level such that prices over the long-term should incentivise enough new investment, as well as operational decisions, so the reliability standard is expected to be met.
- Administered price cap - This $300/MWh cap applies when an administered pricing period is declared by AEMO whenever the sum of the spot price in the previous 336 consecutive trading intervals (that is, seven days) exceeds the cumulative price threshold.[26] Once invoked, the administered price cap remains in place until the end of the trading day during which the rolling sum of prices falls below the cumulative price threshold. To date, the administered price cap has rarely been triggered.

2.2.3 Information processes

AEMO is required by the NER to publish various materials which provide information to market participants – and any other interested parties – on matters pertaining to the reliability standard; that is, over and above the information contained in contract and spot market prices. This information is provided in several formats and considers various time-frames.[27] As noted above, this information is an important part of the existing reliability framework to helps guide and inform market participants' expectations of the future, enabling more efficient investment and operational decisions.

These information processes are described in more detail in chapter 3.

The purpose of these forms of supplementary information is to inform the market of prevailing and forecast conditions, and when reserves may be running low, in order to elicit a market response. For example, if the Electricity Statement of Opportunities (ESOO) identifies a potential shortage of generation in a location in, say, five years' time, the intent is that revealing this information to the market will prompt new investment to alleviate a potential problem. Similarly, the medium-term projected assessment of system adequacy (PASA), which looks forward two years and is updated weekly, enables generators to plan or modify their maintenance schedules.

26 This is indexed annually by CPI by the AEMC.

27 The appendix in the directions paper provides more detail on what information is available to market participants over different time periods.

2.2.4 Intervention mechanisms

As effective as information processes can be in delivering the desired reliability outcomes through market incentives, they do not always elicit the outcomes needed. If the market fails to respond to the information AEMO publishes (for example, shift outages in order to increase production), AEMO's next step is generally to engage in informal negotiations with market participants to alleviate any supply shortfalls. 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 those options fail, AEMO may have no other choice but to intervene in the market more directly.

AEMO therefore has various 'last resort' intervention powers that enable it to deal with actual or potential shortages of varying degrees of severity. In each instance, the power in question is designed to be implemented in a way that results in the smallest distortion possible to the operation of the market. Under the NER, these intervention mechanisms include the following:

- 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 standard, and where practicable, for power system security. AEMO can dispatch/activate these reserves to manage power system reliability and, where practicable, security.
- In addition, if there is a risk to the secure or reliable operation of the power system, AEMO can use directions or instructions under NER clause 4.8.9 to:
    - Direct a generator to increase its output, if this is possible and can be done safely. To be effective, the generator must have enough time to '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 industrial plant, to temporarily disconnect its load or reduce demand.

If there continues to be a shortfall in supply, even after these measures have been implemented, AEMO may require involuntary load shedding as a last resort to avoid the risk of a wider system blackout, or damage to generation or network assets. It does this by instructing a transmission network service provider to arrange for the interruption of consumer load under clause 4.8.9 of the NER. These intervention mechanisms provide an important ultimate safety net when there is insufficient generation capacity to maintain adequate reserves above demand, to minimise the adverse impacts on customers of involuntary load shedding. Although AEMO would be expected to do all in its power to avoid load shedding using the above intervention mechanisms, there will be times when involuntary load shedding will be unavoidable because the level of investment and operational decisions are being driven by a reliability standard that is non-zero.

These intervention mechanisms are described in more detail in chapter 6.

2.3 Challenges to the existing framework

Australia's energy system is undergoing a transformation - driven by changing consumer choices and rapidly evolving technology:

- Consumers are now better-equipped than ever to manage and control their energy use and contribute to reliability and this capability will continue to improve in the future as technology advances. The emergence of distributed energy resources such as small-scale PV systems (of which there is now around 5,700MW in the NEM) and the steadily declining cost of battery storage means that these technologies may already be an efficient source of back-up capacity in some circumstances (furthermore, relatively broad geographic dispersion generally helps.)[28] Those possibilities will expand in the future with AEMO estimating that, by 2036-37, nearly 20,000MW of roof-top solar PV will have been installed, together with more than 5,500MW of residential and commercial battery storage.[29] For comparison, total existing capacity in the NEM is around 48,000 MW.[30]
- Variable, weather dependent renewable generation in the NEM, including residential solar PV, has increased substantially since 2001, with considerable investment over the last ten years - see Figure 2.4. This has had an impact on the amount of scheduled generation in the NEM - in 2001, approximately 100 per cent of registered generation in the NEM would be considered to be able to be "scheduled"; however, this is now closer to 80 per cent. The capacity of variable renewable generation is expected to continue to increase with committed wind and utility solar projects - there are nearly 40 wind, solar, bioenergy or hybrid projects currently under construction in the NEM with another 14 with financial commitment.[31] This has been incentivised by factors such as: generous feed-in tariffs provided by state governments, which have provided strong financial incentives to install roof-top solar PV; the large-scale renewable energy target (LRET), which has provided strong additional incentives for the private sector to invest in large-scale renewable generation, particularly wind farms; capital incentives provided in terms of credits from the small-scale renewable energy scheme; and government grants through ARENA and long-term contracts under the ACT Government's reverse auction scheme as well as QRET and VRET. This has been combined with a strong trend of thermal (coal-fired) generation exiting, including Northern Power Station in South Australia (520MW in May 2016), Hazelwood Power Station in Victoria (1,600MW in March 2017) - see Figure 2.3 below. Moreover, the Liddell Power Station in New South Wales (2,000MW) is expected to close in 2022.

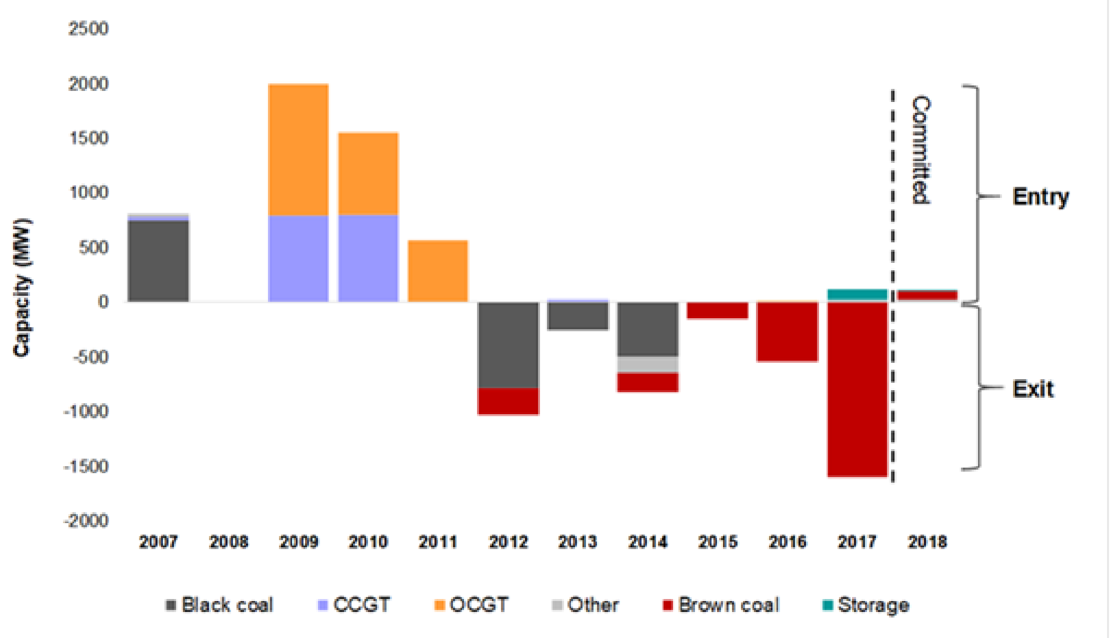
28 In the absence of adequate storage capacity, solar PV that is clustered in a single geographic area can give rise to reliability problems. For example, it can result in sudden drops in supply during times of cloud cover when large numbers of plants stop producing all at the same time.

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

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

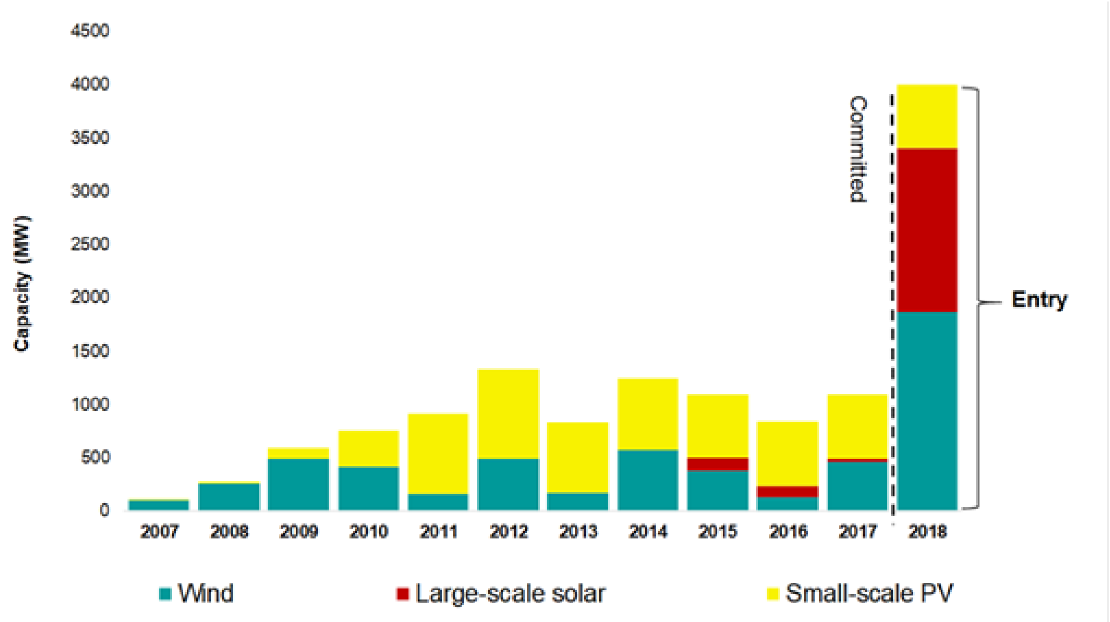
31 See: https://www.cleanenergycouncil.org.au/policy-advocacy/jobs-and-investment.html

Figure 2.3: Changes in scheduled generation capacity by fuel type



Source: Endgame Economics analysis for the Commission

Figure 2.4: Entry and exit of renewablesplant by technology type



Source: Endgame Economics analysis for the Commission

This transformation also includes changing electricity demand patterns and the impact of weather events. Reflecting this, AEMO, the system operator, has recently identified and highlighted where security and reliability needs are shifting across the national electricity market (NEM), including how these factors are impacting on the operation of the system.[32] Further, the reliability and security of the NEM has attracted considerable attention in recent times from both the media and various policy makers.

Meanwhile, various policy settings – including a lack of an enduring emission reduction policy, but multiple policies to support investment in renewable technologies – are having a profound influence on consumption, investment and operational decisions. There has been a prolonged uncertainty over a long-term emissions reduction mechanism that is integrated with the energy market; with the potential impacts on this on the reliability framework becoming more acute as time passes. It is this uncertainty that the ESB's proposed Guarantee is seeking to address.

In addition, prospective investors in new generation may also be disconcerted by the increasing role of the state and Commonwealth governments in funding, subsidising or studying the feasibility of additional dispatchable generation capacity. Private investors may be less inclined to invest in new generation for fear that their returns could subsequently be truncated by government-sponsored initiatives.

2.3.1 Impacts on reliability

These forces are raising questions about the ongoing suitability of the existing reliability framework, for example:

- intrinsic intermittency of wind and solar plants can make it considerably harder to forecast their output than other forms of generation, although advances in technology are making it easier to undertake this forecasting
- much of the variable renewable generation being installed is non-dispatchable (at least in the absence of adequate storage capacity, for example, large banks of batteries)
- the displacing of scheduled capacity with variable renewable generation has the potential to affect the availability of standard hedging contracts. To date, variable renewable generation has typically been underpinned by long-term power purchase agreements rather than relying on selling hedge products in the contract market (although there are signs that this investment model is changing as the cost of renewable generation drops).

However, to date, as noted above, reliability events have been well within the reliability standard.

There is a significant body of work underway that is currently considering how to maintain the reliability of the NEM. This includes the Energy Security Board's (ESB) proposed National Energy Guarantee. The Guarantee seeks to integrate energy and climate change policy instruments in the NEM to provide investors with the certainty to make long-term

32 AEMO, submission to the interim report, p. 3. See below for definitions of security and reliability.

investments. The COAG Energy Council will consider the Guarantee at its meeting in August 2018.

In addition, a number of rule change requests are either being progressed or have recently been concluded by the Commission that make changes to the current reliability framework which have been progressed through the Commission's reliability work program:

- the Reliability Panel's review of the reliability standard and settings that will apply from 1 July 2020: in April 2018, the Panel published a final report and recommended that the reliability standard and settings for the NEM remain unchanged for the period 1 July 2020 to 1 July 2024
- a final determination on a rule change request from AEMO to improve information AEMO provides to signal whether electricity is projected to meet demand in the medium-term
- a final determination on a rule change request from AEMO to allow AEMO to contract for electricity reserves up to nine months ahead of a projected shortfall under the RERT - the market's existing strategic reserve mechanism
- a final determination on a rule change request from the COAG Energy Council to make the AER responsible for calculating and updating values of customer reliability, used to develop reliability standards
- a consultation paper was published in April 2018 on a rule change request from Dr Kerry Schott AO to introduce a three-year notice of closure for generators, which is focussed on the provision of additional information to AEMO on expected closure dates, including a proposed requirement that scheduled and semi-scheduled generators provide at least three years' notice of when they will cease to supply electricity or trade directly in the market and
- a consultation paper was published on a rule change request from AEMO on broader changes to the RERT framework. A draft determination is due to be published in October 2018.
- In April 2018, the Commission published a discussion paper for the *Coordination of Generation and Transmission Investment* review which examines implications for the transmission framework of the changing generation mix. A directions paper is due August 2018.

This Review should be considered in that context; considering complementary changes to energy market design to deliver long-term reliability to consumers at least cost.

2.3.2 Impacts on security

Operationally this change in generation mix has been and remains challenging for system security because the different generators have different characteristics. The rules of physics dictate various technical features that are needed for system security - like frequency control, inertia, and voltage parameters. Coal, gas and hydro generation have spinning generators, motors and other devices that are synchronised to the frequency of the power system. This synchronous generation provides a number of aspects of system security almost as a by-product. To date, that by product has not been separately valued and priced. Wind and solar photovoltaic powered generators do not readily provide these features easily though the relevant technology is evolving. As the proportion of non-synchronous generation rises, the security of the power system is becoming more challenging to maintain.

Issues arising from the changing generation mix on security include, among others:

- frequency performance under normal operating conditions has been deteriorating in recent times, evidenced by a flattening of the distribution of frequency within the normal operating frequency band
- decreases in available system inertia, resulting in increased challenges to maintain the system
- as traditional, synchronous generators retire and are replaced by increasing numbers of non-synchronous generators connected to the power system by inverters, the system strength is decreasing.

In relation to security a number of changes have already been made to the security frameworks. Projects completed and under way under the Commission's security work program include the following:

- In March 2017, the Commission made a final rule to help protect the power system from emergencies through a new management framework for emergency frequency control schemes.[33] These are 'last line of defence' mechanisms such as controlled load shedding, designed to protect against a major blackout if a sudden and unexpected loss of generation or load causes rapid changes in system frequency. The new rules require AEMO to regularly and transparently assess emerging risks caused by swapping out older synchronous generators, for non-synchronous generation technology like wind and solar.
- In September 2017 the Commission made final rules to:
  - manage the rate of change of power system frequency[34] – enabling better frequency control by making networks provide minimum levels of inertia and, with AEMO approval, enabling networks to contract with suppliers to provide inertia substitutes
  - manage power system fault levels[35] – keeping the system stable by making networks provide minimum levels of system strength at key locations, and requiring new generators to pay for remedial action if they impact system stability
  - improve guidelines for generating system models[36] – requiring generators and networks to provide more detailed information about how their equipment performs so AEMO and networks have the right data to efficiently plan and operate the system.[37]
- In June 2018, the Commission published a draft determination on a proposal for new technical performance standards for connecting generators.[38] The rule change proponent,

33 See https://www.aemc.gov.au/rule-changes/emergency-frequency-control-schemes-for-excess-gen
34 See https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque
35 See https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels
36 https://www.aemc.gov.au/rule-changes/generating-system-model-guidelines
37 This rule change was proposed by AEMO.
38 See https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

AEMO, considers that tighter generator technical standards are needed to help keep the system secure in the future as the changing generation mix makes the system more difficult to manage in some locations. The AEMC made a draft rule that proposes a flexible approach to setting standards that enables targeted, least-cost ways of connecting new generators.

- The *Frequency control frameworks* review is underway, which is looking at ways to integrate new technologies and demand response to help keep the system secure, as well as considering new ways to deliver more inertia where this provides additional benefits to the system. A draft report was published in late March 2018, ahead of a final report in late July 2018.[39]
- On 26 June 2018, the Commission published a draft determination for the *Register of distributed energy resources* rule change request - the draft rule establishes a register of distributed energy resources (DER). The register would give the Australian Energy Market Operator (AEMO) and network service providers (NSPs) visibility of where DER devices are connected so they can plan and operate the power system more efficiently.[40]

2.4 Market responses to challenges

There have been numerous announcements that show that the market is responding, many of them focussing on the demand side. For example:

- Reflecting an increasing focus on the demand-side and technological developments, Flow Power has recently announced an expansion of its operations, expanding into two new cities and employing new staff. Flow Power connects its business customers to market signals and wholesale power prices, and gives it customers the ability to control load in response to price fluctuations, while still being scalable.[41]
- Also reflecting an increasing focus on the demand-side, Powershop and Reposit Power are working together on a program that will help Powershop dispatch surplus solar battery capacity during demand peaks. The program, known as Grid Impact, guarantees payments to customers that have signed up and agreed to let Powershop control their solar batteries during peaks. Powershop will then use the program to represent cap contracts to manage its risk.[42]
- Similarly, another example of facilitating the demand side is GreenSync's Decentralised Energy Exchange (deX), which is a proposed digital marketplace that changes the way energy is produced, traded and consumed. Specifically, deX is a software platform designed to drive the development and implementation of distributed energy resources throughout the energy market. The platform allows distributed energy resources to participate in energy markets by making them visible and enabling stored energy to be dispatched on command.[43]

39 https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

40 See https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources

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

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

43 See https://dex.energy/.

- Reflecting the changing generation mix, participants are starting to look to create more balanced portfolios to better manage their risks in the wholesale market as the generation mix transforms. For example, on 1 February 2018 Meridian Energy entered into an agreement to purchase three hydro power stations from Trustpower, and signed three power purchase agreements for wind and solar projects in Victoria and New South Wales. It was noted that "having a balanced portfolio of wind, solar and hydro allows [Meridian] to more effectively manage risk in the market".[44] Similarly, on 7 February 2018, Tilt Renewables plans to build a 44 MW solar farm and 21 MW battery system to connect to its existing wind farm new Snowtown. It also plans a 300 MW pumped hydro energy storage project in South Australia's disused Highbury quarry.
- AGL has announced a new derivative product that seeks to 'firm up' wind generation. The product is a financial derivative that is exercised when wind generation across a region starts to fall. By financially firming up wind generation, the owners of wind farms can enter into swap contracts with other parties. This product is explained in more detail in chapter 5.
- Despite policy uncertainty around emissions, Energy Australia recently noted that it is looking at investing in more than 1000 MW of new gas-fired plants at Tallawarra and Marulan in NSW, and a new gas generator is possible at Yallourn coal generation site in Victoria.[45]
- ERM Power's solar firming product to "help manage the risks of intermittent generation". The solar product is part of a new generation of financial instruments which respond to the evolving Australian market, with the first trade being finalised within days of the product being released to the market. The product will help support investment in renewables by providing fixed price certainty for organisations wanting to hedge solar generation production.[46]

44 Powershop, Media Release, Meridian Energy Australia invests in renewable energy by adding hydro, solar and wind projects to meet on-going customer growth, 1 February 2018.

45 See: http://www.afr.com/business/energy/electricity/energyaustralia-eyes-new-gas-generators-in-ns w-vic-20180302-h0ww7n

46 See: https://www.ermpower.com.au/new-generation-financial-products-launched-support-renewables/

3 INFORMATION PROVISION

The Commission considered whether the provision of more information could improve reliability outcomes by allowing market participants, the system operator, regulators and policy makers to make better-informed decisions. Specifically, the Commission looked at:

- the level of transparency around existing centralised forecasts and measures that could be taken to improve transparency
- day-ahead markets and whether this would be an effective mechanism to provide more, or better quality, information to market participants and the system operator
- the availability of information to assess the health of the contracts market.

The Commission's findings and recommendations on each of these items are set out below.

3.1 Centralised forecasting transparency

3.1.1 Background

The role of forecasting in the NEM is to provide market participants and AEMO with the best estimate of expected future conditions, so that decisions that must be made today produce efficient market outcomes in the future. This is the case for both short-term (i.e. expected conditions for the coming minutes and days) and long-term forecasting (i.e. looking weeks, months and years into the future).

Some forecasting is done by AEMO, while some is done by participants themselves. AEMO provides a range of forecasts to the market of metrics such as demand, supply and price, which cover a range of time frames. These are based on its own analysis, as well as information provided by participants as inputs to its processes.

Participants, including generators, retailers and network businesses, also do their own forecasting, based on their own view of the future and their market position. The outcomes from participant forecasting activities feed into their investment and operational decisions, as well as the information that they provide continually to AEMO for its forecasting purposes.

Forecasts in the NEM cover time horizons ranging from five minutes to more than 10 years (see Table 3.1 below). Short-term forecasts are inputs to operational decisions by both market participants and AEMO. Examples include a generator deciding to offer its output into pre-dispatch, or AEMO deciding whether to intervene in the market. Longer-term forecasts inform investment and retirement decisions, as well as the timing of maintenance. For example, AEMO's Electricity Statement of Opportunities (ESOO) informs the market of the upcoming supply-demand balance; participants will make investment and retirement decisions regarding generation capacity and demand response capability. In this way, the efficiency of wholesale market outcomes depends on the availability and quality of both short-term and long-term forecasting.

Figure 3.1 shows how short-term and long-term forecasts can be used by participants to optimise investment and operational decisions by an iterative process.

Figure 3.1: Using forecasts to optimise investment and operation decisions

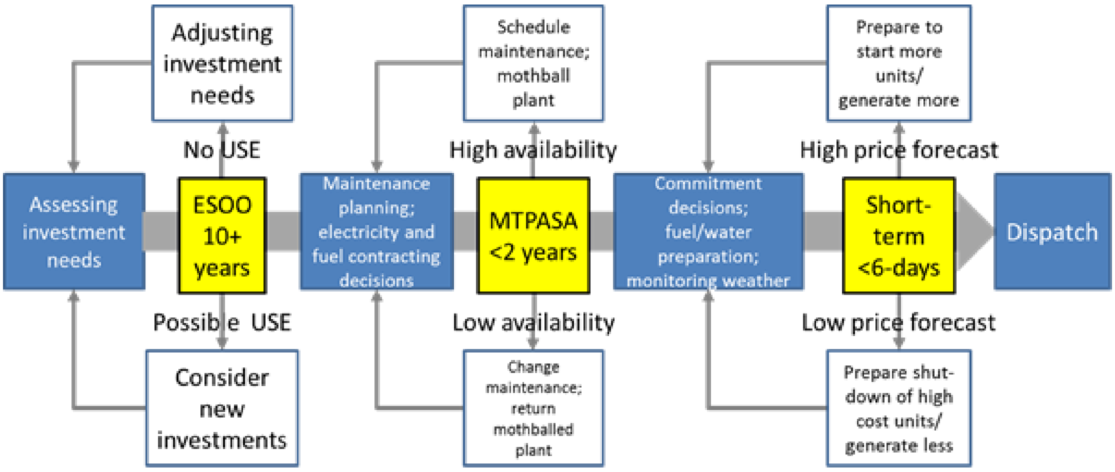


Table 3.1 below sets out the key details and purpose of the forecasts that AEMO currently provides. All of these forecasting processes result in AEMO publishing data and documents that are available to the general public. An exception to this is the medium-term projected assessment of system adequacy (MTPASA) graphs that are now provided through a portal that is only accessible to market participants.

Table 3.1: Summary of AEMO's forecasting processes

FORECAST	TIMEFRAME	FREQUENCY OF PUBLICATION	RESOLUTION	PURPOSE
ESOO	Ten years	Annually (by 31 August) on AEMO's website	Annual	To allow existing and potential new market participants to assess opportunities in the NEM over a 10-year period.
EAAP	Two years	At least annually on AEMO's website	30-minute traces	Provide analysis of the impact of energy constraints (e.g. water shortages, fuel supply constraints) on energy availability.
MTPASA	Two years	Weekly (reliability assessment); three-hourly	30-minutes	Inform market participant decision making in regard to supply, demand and transmission network outages up to two years in advanced.

FORECAST	TIMEFRAME	FREQUENCY OF PUBLICATION	RESOLUTION	PURPOSE
		(regional availability) to market participants and accessible by the public.		Reliability assessment outcomes are also published as required through market notices.
STPASA	Six days	Two-hourly to market participants and accessible by the public.	30-minutes	Inform market participant decision making in regard to supply, supply, demand and transmission network outages in the upcoming six days.
Pre-dispatch	One day	30 minutes to market participants and accessible by the public.	30-minutes	Provides projections of the prices and generation dispatch based on market participants' bids and offers, and AEMO forecasts of demand and other system conditions.
Dispatch	Five minutes	Five minutes to market participants and accessible by the public.	Five minutes	Publishes dispatch information every five minutes.

Note: Clause 3.7.3(a) requires the STPASA forecast to be published at least daily, but AEMO publishes an update to this forecast every two hours.
Note: PASA, pre-dispatch and dispatch spreadsheets containing raw data may be downloaded by the public through a portal - see: http://www.nemweb.com.au/REPORTS/CURRENT/. Pre-dispatch spreadsheets may also be downloaded from AEMO's website.
Note: EAAP = Energy Adequacy Assessment Projection.

More detail on each of these processes, including the inputs, specific information provided to the market, and associated method for identifying potential breaches of the reliability standard, can be found in appendix C of the interim report.

3.1.2 Summary of directions paper

The forecasting and information provision chapter of the directions paper presented the Commission's analysis of AEMO's forecasts and considered potential changes that could serve to make forecasting more effective in the future. A summary is provided below.

Commission's analysis of AEMO's forecasts

The Commission presented analysis of the historical differences between forecast and actual demand in the MTPASA, STPASA and pre-dispatch forecasts.[47] The analysis found that while there have been deviations between forecast and actual values, the degree of deviation has generally not materially changed over the period of time that was analysed. The Commission also noted that this was not surprising since all forecasts are, by definition, uncertain.

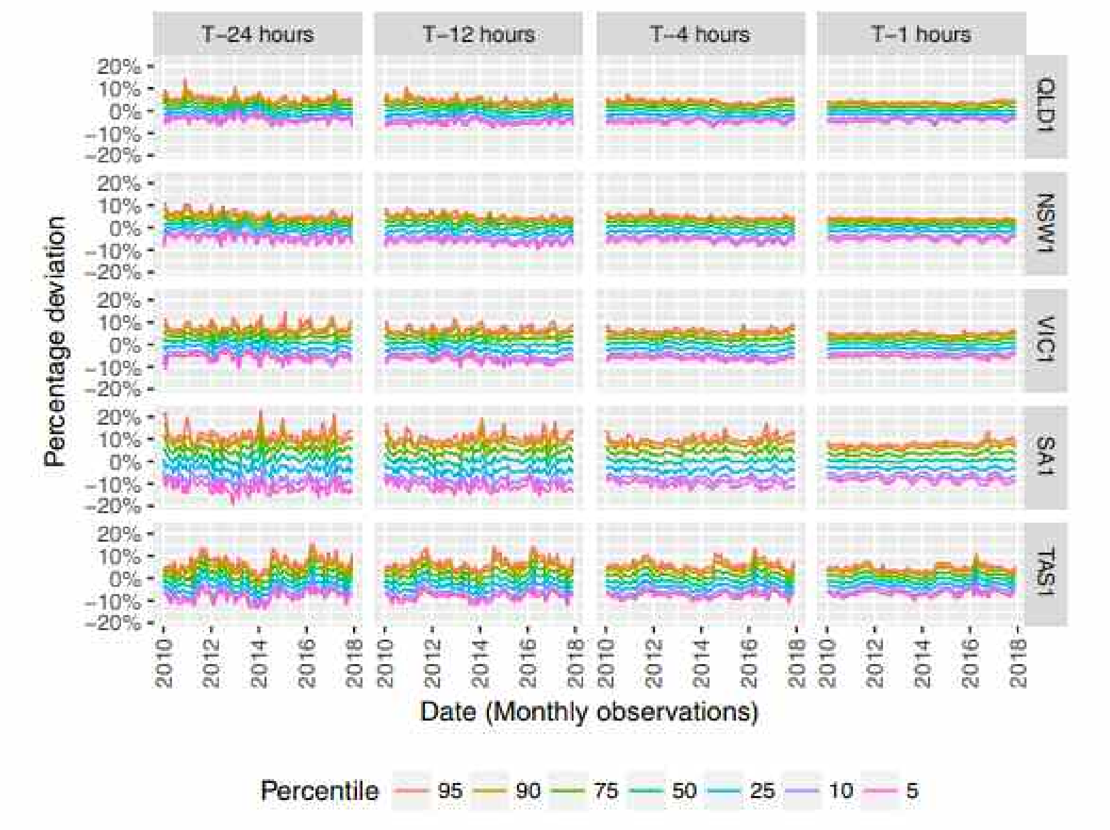
An example of the Commission's analysis is provided in Figure 3.2 below. It shows the differences between the pre-dispatch forecast of demand and actual demand at four different time horizons; the differences are expressed as monthly percentiles of the half-hourly differences. By way of explanation, the x^{th} percentile measures the value at which x per cent of observations are below or equal to a particular value. Thus, if the 75 per cent percentile of a distribution of differences for a whole month is 0.05, this implies that 75 per cent of observations in that month are equal to or less than 0.05. The 50^{th} percentile is the median of the distribution. This approach allows for an examination of how particular percentiles of the distribution have evolved over time.

Figure 3.2 presents this analysis for each NEM region for the past seven years. It provides several insights:

- The forecast deviation values becomes smaller (i.e. forecasts become more accurate) as time approaches dispatch. This is evidenced by the bunching of the percentile lines closer to the x-axis in the 1-hour horizon compared to the 24-hour horizon.
- South Australia has the largest forecast deviation value of all the regions. This can be seen by the spread of the percentiles (i.e. range between the 5^{th} and 95^{th} percentile lines) at the 1-hour time horizon being larger than other regions. Note that the y-axis limits are the same across all of the NEM regions.
- There is some seasonal variation in forecast deviation value, which can be observed in the regular pattern of increasing and decreasing forecast deviation values over the course of a year. This can be seen most clearly in the 10^{th} percentile and 5^{th} percentile forecasts for South Australia and New South Wales in the period after 2014. This implies that the pre-dispatch forecast may not fully account for seasonal variation in demand.

47 AEMC, *Reliability Frameworks Review*, directions paper, 17 April 2018, pp. 57-70.

Figure 3.2: Deviation between pre-dispatch forecast and actual demand



Source: AEMC analysis of MMS data
Note: Percentage deviation = (Forecast – Actual)/Actual × 100%

Commission's analysis of potential changes

While the Commission's analysis found that there has not been any systematic worsening in the differences between forecast and actual values, the Commission also acknowledged, in the Directions Paper that forecasting in the NEM is concurrently becoming:

- more complex due to: greater volumes of variable renewable energy technologies and distributed energy resources (DER), more frequent extreme weather events, and increased demand-side participation through demand response and DER technologies,
- more widely used as more large energy users invest in load control technologies to respond to spot prices, and DER aggregators increase in number and volume.

Both the traditional market participants and these new groups of entities rely on forecasts to some extent in their decision-making. In this context, the Commission considered potential changes to improve the effectiveness of forecasting in the future.

The first potential change was the introduction of periodic reporting on the differences between AEMO's forecasts and actual values. The directions paper noted that there is only limited public analysis of the differences between forecast and actual values of demand, price, weather, and wind and solar generation output. The Commission considered that a common source of such reporting on forecasts would enable industry and AEMO to have better-informed conversations about forecast inputs, outputs and methodologies particularly as the energy sector transforms. The directions paper sought feedback on the potential role of AEMO, the AER and the Reliability Panel in enhanced reporting on centralised forecasts.

Second, the Commission expressed support for the work being undertaken by AEMO and ARENA to enable self-forecasting by utility-scale wind and solar projects on a voluntary basis. Self-forecasting of the upcoming few hours or day ahead could provide benefits for reliability by better informing AEMO and the market of the likely future output of wind and solar generators. The Commission invited stakeholder comments on whether a self-forecasting obligation for wind and solar generation should be implemented through the NER.

Third, the Commission considered demand-side forecasting, whereby retailers would provide AEMO with a forecast of the loads that they are supplying.

3.1.3 Summary of submissions

Stakeholders commented on the Commission's analysis of AEMO's forecasts as well as the three potential changes to improve the effectiveness of forecasting in the future.

In response to the Commission's historical analysis, stakeholders expressed an appreciation for why AEMO would take a conservative approach to forecasting, but also concern with the degree of over-forecasting of demand across all time horizons. In response, AEMO explained that it is pursuing a range of forecasting enhancements to refine its short term forecasting approach, including:[48]

- a move towards risk-based and probabilistic forecasting
- data science techniques and machine learning
- significant improvements in weather forecasting
- using 'consensus forecasting' by receiving weather, demand and generation forecasts from multiple service providers
- new interfaces to allow operators of wind and solar generation and virtual power plants to voluntarily submit forecasts
- a multi-year redesign of the AEMO IT platform to facilitate new forecasting approaches
- investigating transmission connection point forecasting.

Regarding the Commission's potential changes, there was quite a lot of support for the introduction of periodic reporting on the differences between AEMO's forecasts and actual values. Stakeholders saw value in the reporting being undertaken by a third party, and, therefore, thought that it should be the responsibility of the AER.[49] Stakeholders also expressed a more general desire for greater transparency around forecasting methodologies

48 AEMO, directions paper submission, pp. 3-4.

49 Directions paper submissions: Australian Energy Council, pp. 1-2; Energy Networks Australia, p. 3; ERM Power, pp. 4-5; Hydro Tasmania, p. 2.

and assumptions, and for industry participants to have more input into how these are developed.[50] For example, Infigen Energy submitted that more transparency around forecasting would provide participants with greater clarity over when additional resources might be needed, and enable better coordination of energy limited resources and unit commitment decisions.[51]

Stakeholder views on the other two options – self-forecasting by wind and solar generators, and demand-side self-forecasting – are summarised in section 5.4 and section 4.2 respectively. These sections also contain the Commission's analysis and finding or recommendation in relation to each of these matters.

The potential changes were also discussed at the Technical Working Group meeting in June 2018 and feedback from the members of this group has been incorporated in the Commission's analysis and recommendations below.

3.1.4 Commission's analysis and recommendations

While there is already a large volume of information and data released by AEMO in the course of its forecasting activities, and AEMO are constantly improving and refining the information that is made available the Commission considers that given the energy transformation that is currently occurring there is a need for increased transparency or further disclosure in some areas. At a high level, increased transparency is in the long-term interests of consumers, provided that the costs for industry participants and AEMO that are passed on to consumers are less than the benefits of the information being released.

The Commission's consideration of the transparency of centralised forecasting is set out below in the categories of forecasting inputs and forecasting outputs.

Forecast inputs

The inputs to AEMO's centralised forecasting processes include information provided by market participants (e.g. technical capabilities of generation units), the models and methodologies developed by AEMO, and forecasts developed by consultants engaged by AEMO. Considerable detail is already published in the form of process descriptions, assumptions, consultant reports, and conveyed through AEMO's consultation processes and industry forums.

However, the Commission has also heard examples of market participants being unable to undertake detailed analysis of forecast outcomes due to a lack of transparency around the inputs and assumptions. Generally, centralised forecasts will be most effective when they are well-understood via the publication of details on how they are produced – this informs decisions on how the forecasts are used and, if necessary, where improvements can be made. In the absence of this, the decisions of those using the forecasts, and efforts of improve forecasts, may be less efficient than if those involved had been better information through more transparent processes.

50 E.g. directions paper submissions: ERM Power, pp. 3-5; Clean Energy Council, pp. 1-2; Government of South Australia, p. 6.

51 Infigen Energy, directions paper submission, p. 3.

In the interests of efficient decision-making by AEMO and those using the forecasts, the Commission considers that the methodologies used for forecasting should be completely transparent, to allow a full understanding of all inputs and independent verification of the results. To the extent practicable, and subject to any applicable confidentially provisions, the amount of information disclosed should be sufficient so that the forecast outputs are reproducible by anyone with an interest in doing so. This enables more groups to be usefully involved in the development of forecasting methodologies, with potential benefits in the form of better understood forecast outputs and reduced effort for AEMO if participants have greater confidence in the outputs.

To progress greater transparency around forecast inputs, the Commission proposes the creation of a new guideline, to be prepared by AEMO. The proposed guideline would specify the process that AEMO will follow to develop its forecasting methodologies and the information that must be contained within, or released alongside, its public documentation of its forecasting methodologies. The guideline would include:

- how and when AEMO will review its methodologies
- opportunities for participants to be involved in the development and amendment of methodologies, and a process through which AEMO will respond to and incorporate stakeholder feedback
- what information will be included in the public documentation of the methodologies (e.g. an explanation of how AEMO uses the forecast),
- how methodology changes should be communicated.

A key benefit of this guideline over the status quo is that it would be developed though, and subject to, public consultation. AEMO would be required to develop and amend the guideline using the Rules Consultation Procedures, which specifies two rounds of public consultation.[52] This would provide industry participants with a structured opportunity to indicate the forecasting methodology information that they would like to see released, and the ways in which they would like to be consulted about forecasting. Once the guideline has been published, AEMO would be required to comply with it.

The advantage in AEMO developing this guideline, as opposed to an external entity, is that it has full knowledge of the existing forecasting systems and processes, so is best-placed to engage in conversations about the feasibility of potential changes to them. The guideline is expected to give industry participants more opportunities to contribute to the development of forecasts. It is expected to result in all stakeholders having more clarity around forecast methodologies and how the inputs and outputs are used by AEMO. As mentioned above, this is expected to result in more efficient decision-making by AEMO and others who use the forecasts.

The guideline is a more flexible approach than embedding specific requirements in the rules as it will not require a rule change to update it in response to changing market conditions. It can be adapted by AEMO more easily over time to accommodate new forecast methodologies as these are developed, or as the needs of AEMO and market participants change.

52 National Electricity Rule 8.9.

Forecast outputs

The outputs of AEMO's forecasts vary across the different forecasts, but typically include metrics such as demand, generator output levels and prices. The focus of the Commission's historical analysis during this review has been on demand forecasts and the output levels of wind generation as AEMO has more direct control over these than price forecasts, which, by design, change in response to information provided by participants through their bids and offers.

In the directions paper, the Commission observed the existing sources of reporting on forecast outputs:

- AEMO. Under clause 3.13.3(u) of the rules, AEMO must, no less than annually, prepare and publish on its website information on the accuracy of the demand forecasts to date in the most recent annual ESOO publication, and any improvements made by AEMO or other relevant parties to the forecasting process that will apply for the next ESOO.
- The AER. Under clause 3.13.7 the AER must prepare and publish a report that identifies and reviews each occasion when the AER considers that a significant variation has occurred between the 30-minute pre-dispatch spot price forecasts and the actual spot price in any trading interval. The report must state why the AER considers that the significant price variation occurred.
- The Reliability Panel. Some analyses of forecasts are also presented in the Reliability Panel's *Annual Market Performance Review* which is produced in accordance with clause 8.8.3(b) of the NER. However, the requirement to produce this report does not explicitly mandate reporting on forecasts.
- Market participants undertaking their own analysis. Such analysis would typically be targeted at the aspects of the forecasts that are particularly pertinent to that specific stakeholder, as opposed to the interests of all stakeholders. The analysis produced is generally not publicly available.

On this basis, the Commission observed that there is limited public information on the differences between AEMO's forecasts and actual values. Also, the information that exists is somewhat fragmented.

In the absence of broader information being provided to all market participants, some parties may be more informed than others. It may be difficult for interested stakeholders to get a sense about how forecasts are performing over time, e.g. whether there are any noticeable trends in forecasts. If there was a common source of reporting on forecasting, then industry participants and AEMO would be better prepared to have conversations around inputs, outputs and methodology of forecasts, which would be conducive to identifying areas for improving forecasts as the energy sector transforms. In this way, greater transparency around forecasting *outputs* complements efforts to improve the transparency of forecasting *inputs*.

More transparency around trends and drivers in forecasts should help energy market participants to make more efficient decisions. In addition, this may be a lower cost solution to address some of the NEM issues that it is speculated an ahead-market could address.

The Commission has identified two initiatives that would improve the transparency of forecast outputs:

1. AEMO continuously reporting on the differences between forecast and actual values via an automated data release that is publicly available. For example, on a day-after basis, reporting on the differences between forecast and actual pre-dispatch values.[53] This reporting could include demand, output from wind and solar generation, weather, and potentially other metrics as well.
2. The AER producing a public, quarterly report on the differences between forecast and actual values in the MTPASA, STPASA and pre-dispatch forecast processes. This quarterly report would build on the AER's existing weekly reports.[54] The longer analysis period would allow for the identification of trends, such as systematic differences between forecast and actual values in electricity demand and other variables.

AEMO publishing the differences between forecast and actual values via an automated data release would be useful for market participants undertaking their own analysis. As noted above, market participants typically undertake their own forecasting and analysis in order to inform their operational and investment decisions. These are informed by AEMO's forecasts across different timescales. As the energy sector is transforming we understand that it is more difficult for stakeholders to work out what is driving forecasts. If the deviation values were published in a consistent format, daily, this would enable participants to analyse and evaluate trends in forecasts and potential drivers.

We understand that some market participants do this analysis already, but having the values published by AEMO will allow all interested stakeholders to have visibility over them. The new reports should be developed in close consultation with those who use the forecasts, so that the content and structure of the new data reports are aligned with industry requirements. AEMO could then implement this change through their systems, rather than requiring a rule change.

It is not feasible for analysis to accompany these variation values given that these would be published daily through an automated data release. So, instead, it is proposed that the AER would produce a quarterly report on the differences between forecast and actual values in the MTPASA, STPASA and pre-dispatch forecast processes. This would allow the AER to do more comprehensive analysis on forecast outputs and provide commentary that is similar to its existing weekly reports. The methodology would be developed through industry consultation on a guideline setting out the AER's proposed methodology prior to commencing the reporting.

This quarterly reporting would be consistent with the AER's existing responsibility under the NEL to monitor the wholesale market and report on its performance at least every two years.

53 This would complement the information AEMO is already required to publish on a day-after basis under clause 3.13.8(a) of the National Electricity Rules.

54 The existing weekly reports cover spot market prices, significant variations between pre-dispatch forecast and actual prices, generation bidding patterns, FCAS markets, and electricity financial products. See: https://www.aer.gov.au/wholesale-markets/market-performance

It would enable the AER and stakeholders to better understand noticeable trends in forecasts, which may be influencing participant behaviour in the wholesale market.

The two proposals do not apply to the long-term forecast produced through the Electricity Statement of Opportunities (ESOO). As mentioned above, AEMO is already required under the rules to produce a report – at least annually – on the accuracy of its ESOO demand forecasts.[55] The Commission considers that it is appropriate for this process to continue due to the relative complexity of ESOO forecasting, which involves market modelling and multiple consultant reports, and because it is an annual publication. In contrast, the forecasts to be captured in the proposed quarterly AER report are updated much more frequently. Further, a process for increased accountability for ESOO forecasting will be introduced if the National Energy Guarantee is adopted.[56]

RECOMMENDATION 1: IMPROVING TRANSPARENCY OF CENTRALISED FORECASTS

To improve the transparency around the inputs, methodologies and outputs of centralised forecasting, the Commission recommends that:

- The AER submit a rule change request which would require AEMO to consult on and prepare a new guideline that it will follow in developing and amending its forecasting methodologies.
- AEMO continuously provides forecast deviation data, after engaging with industry participants on the content and structure of the new data reports.
- The AER submit a rule change request be submitted for the AER to consult on and prepare a guideline on how they will report on the differences between forecast and actual values in the MTPASA, STPASA and pre-dispatch forecast processes, and produce a quarterly, public report in accordance with the guideline.

3.2 Ahead information features of the NEM

This section relates to the information that could be provided to AEMO and market participants by implementing an ahead market. A broader consideration of ahead markets is provided in appendix D. This is relevant to the consideration of the suitability of a day-ahead market, as recommended by the Finkel Panel.

The NEM, despite not having a formalised day-ahead market, has many features which play a similar role to that of an ahead market. These features include information that is provided to AEMO as part of the pre-dispatch process, supported by a liquid financial derivatives market with rebidding down to five minutes before real time. Rebidding allows participants with the flexibility to adjust their position in response to new information as it becomes available

55 National Electricity Rules clause 3.13.3(u).

56 Energy Security Board, *Forecasting the Reliability Requirement*, technical working paper, June 2018.

including changes in market conditions as well as responding to offers or bids of other participants.

As part of the Commission's consideration of ahead markets we identified the types of information that are available to market participants at each moment in time relative to dispatch – see appendix D of the directions paper. This information includes plant-specific information and information that is available to the market through process such as pre-dispatch, STPASA, MTPASA and market notices. This work highlighted how the information available to participants is used to inform market participants' behaviours in an iterative way, with new information being included into the decisions of participants on a continuous basis (as depicted in Figure 3.1 above).

The analysis of day-ahead markets in the directions paper noted three different objectives that a day-ahead market could be designed to achieve. The first two of these objectives centred on the provision of more, or better quality, information to market participants and the system operator respectively.[57] The objectives were to provide:

- market participants (both demand and supply side) with more, or better quality, information so that they can incorporate this information into their unit commitment or demand response decisions, their bids and offers, and thereby increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.
- the system operator with more, or better quality, information so that the system operator can use this information to manage the system in relation to reliability and security outcomes, while maintaining the current generator self-commitment arrangements.

While submissions to the directions paper were generally not in favour of the introduction of a formalised US-style day-ahead market in the NEM, they encouraged the Commission to consider changes relating to the provision of accurate and timely information in the NEM.[58]

A number of submissions to the directions paper suggested ways to improve the current information provision processes in the NEM. The submissions considered that these more targeted changes are likely to achieve the same objective as an ahead market as outlined above and in more detail in appendix D but at lower cost and therefore should be considered instead of pursuing an ahead market.

Infigen Energy recommended that incremental and no-regrets changes should be pursued first, such as considering of the benefits of additional requirements for pre-dispatch and STPASA, and continuing investigations into of forecast accuracy and potential improvements.[59] The Australian Energy Council stated that the additional information available to market participants under an ahead market could be achieved through progressive improvements of the current information systems.[60]

57 The third objective identified was to provide the system operator (rather than participants) with a schedule to centrally coordinate unit commitment decisions. This is discussed in appendix D.

58 Submissions to the directions paper that supported further consideration of targeted changes to the current arrangements to achieve the same objectives of an ahead market included Major Energy Users, Energy Networks Australia, ERM Power, Meridian, Infigen Energy, AEC, Aurora Energy and AGL.

59 Infigen Energy submission to the directions paper, p.2.

60 Australian Energy Council, submission to the directions paper, p.

The Government of South Australia noted in its submission that it supports the Commission considering targeted changes and imporovements to the current arrangements to achieve some of the proposed objectives of an ahead market as these may be implemented in a relatively shorter period. It is noted however, that this consideration of targeted changes should not be at the exclusion of a detailed consideration of the potential benefits of an ahead market in the NEM.[61]

A possible incremental improvement that is being considered by AEMO is a rule change request to the Commission to extend the length of the existing pre-dispatch forecast from one to seven days. This relates to the Extended Pre-dispatch report that AEMO started producing in 2017 to support the Gas Supply Guarantee mechanism.[62] The report contains indicative regional prices, interconnector flows, binding constraints and aggregate daily fuel use by gas generators. It is designed to assist in the identification of potential gas supply shortfalls. A rule change request would likely seek to formalise the publication of the report by AEMO, as well as the provision of the data that AEMO requires from participants to produce it.

The Commission notes that stakeholders can shape the design and regulation of the market through participation in the rule change process, including by submitting rule change requests. A unique aspect of our role is that any party, except the AEMC,[63] can propose a change to the rules. Rule changes that are recommended as part of an AEMC review can also be requested by any party.[64]

As a result, when stakeholders identify issues with the rules, or in this instance, a potential gap in the information provided to the market, they can submit a rule change request. For example, several stakeholders, in submissions to a 2017 rule change request on the reporting of generation capacity in medium-term PASA,[65] recommended that an additional change be made to enable AEMO to publish the availability of each generating unit in the MTPASA forecast in order to remove asymmetry of information between participants.[66] The Commission noted that this was outside of the scope of that rule change; however, we understand that ERM Power intends on submitting this proposed change as a separate rule change request in the near future.

Through its consideration of ahead markets, the Commission has found that there is a large amount of information available to stakeholders in advance of dispatch. This information, and the processes used to deliver information to the relevant stakeholders are largely fit-for-purpose. There are some improvements that can be made to improve the quality of information available to market participants to inform their decisions. These potential

61 Government of South Australia, submission to the directions paper, p.3.

62 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/Gas-Supply-Guarantee

63 Except for minor and non-material changes.

64 For more information on the rule change process see: AEMC The rule change process: A guide for stakeholders 20 June 2017. Available at: https://www.aemc.gov.au/sites/default/files/content//A-guide-to-the-rule-change-process-200617.pdf

65 Reporting of aggregate generation capacity for MT PASA rule change, see https://www.aemc.gov.au/rule-changes/reporting-of-aggregate-generation-capacity-for-mt

66 ERM Power, InterGen Australia, Macquarie Group Limited, Alinta Energy: submission to the Reporting of aggregate generation capacity for MT PASA rule change. All four submissions are available here: https://www.aemc.gov.au/rule-changes/reporting-of-aggregate-generation-capacity-for-mt

improvements are largely covered by the recommendations above and through rule changes that the Commission is currently considering, or is likely to consider in the future.

> FINDING:
>
> Existing information provision is largely fit for purpose. However, there are relatively minor changes that can be made to improve information provision for participants and AEMO, and if stakeholders identify other information gaps they can submit a rule change request to address this.

3.3 Contract market transparency

In the issues paper, we identified the forward contracts market as playing an important role in supporting reliability in the NEM.[67] We posed questions about the health of the contracts market and we received mixed views in response. Some stakeholders expressed concerns that the changing generation mix and increased vertical integration was reducing contract trading to levels that might stifle new investment. In contrast, others did not feel there was any cause for concern and provided examples of and healthy signs of adaptation to the spot prices signalled by the changing mix of generation.

In the interim report, we looked at information on electricity futures trading on the ASX platform to see if it showed a decline in liquidity that supported the concerns of some stakeholders.[68] We found that, while trading on the ASX had waned in recent years, it was not universally occurring in every region of the NEM and had not declined to levels that should be cause for concern. However, we noted that forward price curves provide a key piece of information to support efficient investment and operational decisions and repeated the following concern expressed in the Commission's *2017 Retail energy competition review* final report: information on the contract market is not widely available, providing an advantage to the relatively few large businesses that make the most trades and making it hard to evaluate the health of the market.[69]

The reason for our concern was that it has been difficult to assess the over-the-counter (OTC) side of the market since the AFMA survey was discontinued after the 2015 report. This lack of visibility means that it is not possible to properly gauge the health of the contracts market. For example, some claim a reduction in ASX trading is a symptom of liquidity in the market reducing overall. However, it could be because of a shift from exchange traded to OTC contracting, without any change in overall market liquidity. In fact, in its final report of the Retail Electricity Pricing Inquiry, the ACCC surveyed retailers about OTC trading and found

67 AEMC, Issues paper – Reliability frameworks review, https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review, 22 August 2017, accessed on 12 June 2018.

68 AEMC, Interim report – Reliability frameworks review, https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review, 19 December 2017, accessed on 12 June 2018.

69 AEMC, 2017 Retail Energy Competition Review, https://www.aemc.gov.au/markets-reviews-advice/2017-retail-energy-competition-review, 25 July 2017, accessed 12 June 2018.

that OTC trading of swaps and caps appears to have been at a low point in 2014-15 and significantly increased in the last two years.[70] This proves that, without visibility on both OTC and ASX trading, it is not possible to draw inferences on the overall health of the contract market.

While we have acknowledged and welcomed the announcement by AFMA to reinstate its survey of OTC contract volumes, the Commission is unsure it is enough to address stakeholder concerns about the coverage and accuracy of the information it provides.

With this in mind, the Commission, in its *2018 Retail energy competition review*, noted repeated concerns from retailers about the contract market being a barrier to entry or expansion for small retailers.[71]

To improve the ability of policy and regulatory agencies to understand the market and the market circumstances of consumers, the Commission in the *2018 Retail energy competition review* recommended that the AEMC work with industry to make data on OTC electricity contracts available to the market in a form that enhances transparency of the wholesale cost of energy. The Commission notes the ACCC's final report also contains concerns about transparency in the contract market and makes a similar recommendation:

- Recommendation 6 of the ACCC's report is to amend the NEL to require the reporting of all OTC trades to a repository administered by the AER. Reported OTC trades should then be disclosed publicly in a de-identified format that facilitates the dissemination of important market information without unintentionally revealing the parties involved. The requirement should be implemented to align with (or be eligible for) any OTC reporting requirements under the NEG. The AER, AEMC and AEMO should have access to the underlying contract information, including the identity of trading partners.

The box below presents the regulatory arrangements in New Zealand as an example of a mechanism to improve transparency of the contract market.

BOX 2: **TRANSPARENCY ON CONTRACT TRADING IN NEW ZEALAND**

Market participants in the New Zealand wholesale electricity market are required to lodge details of all hedge transactions (exchanged traded and OTC contract), with a third party appointed by the Electricity Authority.

The third party is required to maintain and publish specific details of each contract without revealing the identity of either counterparty. The seller or buyer is required to lodge the date the trade was signed, the effective (start) date, and the end (expiry) date of the contract, the location (one of five geographic zones), the quantity (MWh), the type of contract (e.g. swap, load-following swap, option), whether or not the contract is for all trading periods, contains

70 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018, Table 5.2, pg. 116.

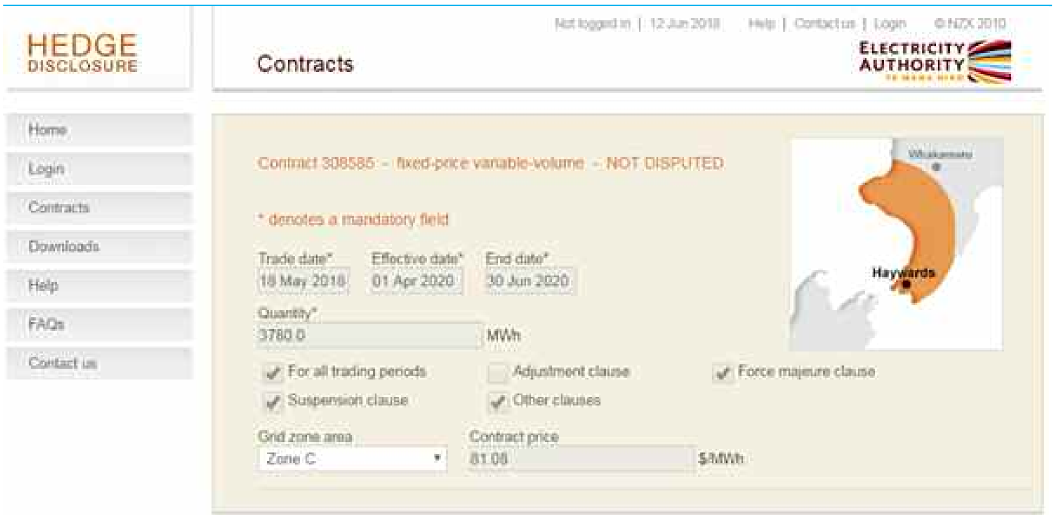
71 AEMC, 2018 Retail Energy Competition Review, June 2018, accessed 3 July 2018.

clauses for adjustment, force majeure, suspension, and other bespoke clauses. The counterparty that lodges the details of the contract must include contact details of the other counterparty, who is then required to either confirm or dispute those details.

The details of each ASX contract must also be lodged but they cannot be confirmed because ASX stands between the buyer and seller and it is not a participant. This means that ASX contracts must be identified separately as the details of a single contract are lodged by both the buyer and seller if they are both market participants.

Figure 3.3 below is a screenshot of the New Zealand electricity hedge disclosure website. It shows the specific details on this contract that are required to be disclosed under this reporting regime.

Figure 3.3: : Example of contract lodged to the Electricity Hedge disclosure website



Source: www.electricitycontract.co.nz

4 INTEGRATING DEMAND INTO THE WHOLESALE MARKET

The wholesale market facilitates the trade of electricity between suppliers and consumers. Historically the demand side has been passive in its involvement in the wholesale market. However, this is unlikely to remain the case as consumers become increasingly capable and willing to actively participate. Technology developments are making it easier for consumers to participate as well.

Energy markets are changing. A range of new products and services are emerging that are redefining the way in which electricity is supplied to consumers, how consumers engage with the market and how and when electricity is used. Consumers can benefit from the evolving market arrangements and through their choices provide important signals to businesses across all aspects of the electricity supply chain.

An active demand-side, characterised by the active participation of consumers promotes efficient outcomes in the wholesale market. The supply side of the market provides a product or service at a price, and the demand side (i.e. consumers) responds to the price/value of the product or service being offered. Where load can effectively respond to prices, it can "choose" its level of consumption based on its willingness to pay for consuming electricity compared to the cost of that electricity.

Since 2013, a number of rule changes originating from the *Power of Choice* review have been implemented. These include changes to the principles for distribution pricing, new metering frameworks, measures to address access to consumers' data, improvements in demand side participation information provided to AEMO, and demand management incentives and enabling demand response.

In the longer term, the Commission considers that the active role of the demand side in the wholesale market will be much more prominent, resulting in a genuine two-sided market. The demand side will therefore play an integral role in the future of the NEM. This chapter explores how the demand side can be better integrated into the wholesale market and identifies a number of steps towards this goal.

4.1 Wholesale demand response

The Finkel Panel recommended that:

> The COAG Energy Council should direct the Australian Energy Market Commission to undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market. This review should be completed by mid-2018 and include a draft rule change proposal for consideration by the COAG Energy Council.

The Commission has addressed this recommendation in this Review.

The Commission notes there are different types of demand response:

- wholesale - market-driven demand response used to change the quantity of electricity bought in the wholesale market in response to wholesale prices, or to help market participants manage their positions in the contract market
- emergency - demand response employed as an emergency lever by the system operator during supply emergencies, the service being centrally dispatched or controlled to avoid involuntary load shedding
- network - demand response employed to help a network business to provide network services to consumers
- ancillary services - demand response employed for providing ancillary services e.g. participating in the frequency control ancillary service markets.

While a single set of equipment can often provide several of these different types of demand response , the services provided are separate. While wholesale demand response and ancillary service demand response participate on a wholesale market level, network demand response and emergency demand response do not. In keeping with the Finkel recommendation, the focus of the Commission's attention for its review has been on facilitating **wholesale** demand response.[72]

During the course of this Review, the Commission has considered how to best to facilitate the demand-side, and in particular, demand response in the wholesale market. We have set out a package of recommendations that seek to remove barriers and provide a range of additional tools to help the demand-side attain more price certainty ahead of real time, while preserving the market-based arrangements in the NEM that allow for flexible and resilient frameworks. These recommendations complement each other and act in concert to facilitate demand response in the wholesale market.

There has been significant interest from multiple stakeholders - representing a range of industry participants - who have noted that they intend to submit a rule change request to the Commission to implement our a way for demand response aggregators to be treated on equal footing with generation i.e. implement a demand response mechanism. The Commission welcomes this - integrating demand response into the wholesale market is a critical component of facilitating the energy sector transition and so we do not consider there should be any delays in progressing this issue. If the Commission has not received a rule change request from one of these stakeholders by the end of August 2018, then it will draft a rule change request that the ESB can submit.

In addition, AEMO and ARENA will be trialling "in-market demand response". The objective of this trial is to demonstrate the potential to increase wholesale market competition by improving access of demand-side resources to spot market pricing. Under the trial, demand response would be provided to the spot market by the customer / aggregator which displaces the energy which would otherwise have been provided by the marginal generator. As an in-

72 The Commission is considering emergency demand response through the *Enhancement to the Reliability and Emergency Reserve Trader* rule change request, see: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader. The Commission is also looking at ancillary services demand response in our *Frequency control frameworks review,* see: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

market trial, the majority of the revenue would be earned in the spot market, paid for by retailers and dispersed to demand response providers through the market settlement system.

RECOMMENDATION 2:

In order to facilitate increased demand response in the wholesale market, and in response to Finkel Panel recommendation 6.7 we consider that:

- A voluntary, contracts-based short-term forward market be implemented that would allow participant-to-participant trading of financial contracts closer to real time providing the demand side with more opportunities to lock in price certainty, and so making it easier for large demand side consumers to engage in the wholesale market and demand respond (i.e. reduce consumption) in response to expected wholesale prices. AEMO should undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market.
- Demand response providers should be able to be recognised on equal footing with generators in the wholesale market and so being able to more readily offer wholesale demand response in a transparent manner to AEMO. The Commission understands, through their submission to the Review, that TEC and PIAC will submit a rule change request to the AEMC to implement such a mechanism by end of August 2018. If these stakeholders have not submitted a rule change request by this time then the Commission will draft the rule change request for the Energy Security Board to submit. This will be supported by testing the practicability and costs associated with this, with in-market demand response trials being undertaken by AEMO and ARENA.
- Consumers should be allowed to engage multiple retailers /aggregators at the same connection point (multiple trading relationships), promoting competition between retailers, supporting new business models for demand response and providing consumers with greater opportunities to engage in wholesale demand response with parties other than their incumbent retailer. Subject to outcomes of the relevant trials, AEMO should develop a rule change request to submit a rule change request to the Commission to implement multiple trading relationships.

The recommendations are summarised below. Appendix A provides a comprehensive outline of the Commission's approach and more detail on the recommendations.

4.1.1 Introduction

The framework for facilitating wholesale demand response should be flexible and resilient enough to remain fit for purpose irrespective of what the future may bring. New products and services for wholesale demand response will have the potential to benefit consumers, but the regulatory framework needs to enable this evolution in line with consumer preferences.

It is important that consumers are provided with choices in how they generate their own electricity, better manage their consumption and engage in demand response. Therefore, we need to provide a range of options for how wholesale demand response can be facilitated - allowing parties to innovate, and consumers to exercise choice in how and when they provide wholesale demand response. This also promotes flexibility and resilience in the regulatory framework to accommodate consumer preferences.

To provide consumers with choice, our recommendations are seeking to address the aspects of the market that may currently restrict the opportunities available to consumers. To provide more choice to consumers, it is important that parties other than the existing retailers can be provided with opportunities to provide demand response offerings to consumers. As recognised in our *Retail Competition Review*, retailers have been slow to innovate on tariff, pricing and products, consumers have also taken matters into their own hands, with increased investment in distributed energy resources, such as solar PV systems and batteries. This applies equally to demand response as well.

It is also important to provide consumers with tools to achieve price certainty. Undertaking demand response will often mean that a consumer incurs a cost such as lost productivity. However, if a consumer does not have confidence that the avoided wholesale electricity costs would outweigh the incurred costs a consumer may not be able to undertake demand response, even where it is efficient.

Our recommendations therefore seek to facilitate demand response in the wholesale market, by removing potential restrictions to providing wholesale demand response and provide more tools to help the demand side attain more price certainty ahead of real time, while preserving the market-based arrangements in the NEM underpinned by flexible and resilient regulatory frameworks.

4.1.2 Implementing a voluntary short-term forward market

The Commission considers that there would be benefit in introducing a voluntary, contracts-based short-term forward market into the NEM to facilitate trading of financial contracts between participants closer to real time. We consider that AEMO should undertake work to submit a rule change request to the Commission by the end of 2018 to implement a voluntary, contracts-based short-term forward market.

Short term forward markets assist participants with concentrating trading liquidity at a certain point in time; as well as allowing market participants to fine tune previously traded positions ahead of real time and/or to hedge against volatility in the real time market. This aids the ability of market participants to enter into longer term financial hedging products.

Under the current market arrangements, a number of stakeholders on the demand-side have highlighted uncertainty regarding future wholesale prices as a barrier to undertaking demand response. For example, a consumer might observe a forecast high price and commit to undertaking demand response. However, in real time, if the forecast high price does not eventuate the consumer would not see the benefit of undertaking demand response.

These challenges are not unique to the demand side - generators in the NEM make the same decisions based upon expectations of future prices. However, as noted in chapter 2, generators use financial instruments to provide them with greater price certainty since these financial instruments have the effect of locking in a price ahead of real time. Similarly, retailers use financial contracts to manage the volatility of the wholesale price.

However, smaller consumers may find it difficult to enter into these financial contracts on an enduring basis. Smaller consumers may be able to more actively participate and manage price uncertainty in a shorter timeframe where they have a better understanding of expected production and maintenance schedules.

As such, a voluntary contracts-based short-term forward market would provide more opportunities to the demand side attain greater price certainty ahead of real time.

These markets could be considered to the current market arrangements, where market participants enter into and supply financial contracts. While there are no regulatory barriers to establishing a short-term forward market in the NEM, such a market has not developed. The lack of such a market developing could indicate a lack of appetite from market participants for such a short-term forward market. However, given we have heard from participants that there would likely be benefits in a short-term forward market, it is possible a market failure exists. For example, the relatively high transaction costs of negotiating OTC contracts and credit arrangements for contracts of a short tenure could preclude the development of short-term OTC products. Similarly, the additional prudential obligations of trading ASX futures and OTC contracts may reduce the attractiveness for some parties looking to trade short term products.

A market that facilitates shorter-term financial trading of financial contracts in the NEM would serve a number of useful purposes that could lead to increased demand side participation in the wholesale market. These include:

- providing market participants with greater confidence in the price signal, by enabling them to lock in a price for consumption ahead of time which would provide price certainty
- potential for greater demand-side participation due to increased price certainty
- providing greater opportunities for participants to manage wholesale price risk
- concentrating liquidity in financial contracts at a certain point in time closer to dispatch
- increased flexibility by allowing market participants to fine tune previous traded positions
- providing more information to participants regarding the state of the market ahead of real-time
- may allow for greater participation of gas, wind and solar generators by:
  - allowing greater certainty for gas generators to source short-term gas on the gas supply hubs
  - more closely aligning with the time frames over which a wind or solar generator could forecast with a greater degree of certainty.

There are a number of design choices that would need to be made designing a voluntary contracts-based short term forward market. One possible model of this market is that it could be run by AEMO and have the following design features:

- a voluntary exchange, similar to the Gas supply hubs (GSH)
- anonymous bids and offers matched continuously throughout the day based on price and volume
- daily contracts traded on a rolling basis for the following day and up to seven days in advance
- flat contracts for a 24 hour period as well as blocks across the day to manage peak, off-peak and shoulder periods.
- separate contracts linked to each regional reference price in $/MWh.

This is one potential design of a short-term forward market. Different design choices could be made which would impact on the outcomes of the short-term forward market and the implementation costs.

A decision on the final model will be influenced by a range of legal issues that require further consideration. These issues may also impact on potential benefits and timing.[73] For example, options for credit risk management and settlement, such as integration with the NEM prudentials and settlements systems would need to be considered; depending on the market design operation of the short-term forward market, financial services licences under Chapter 7 of the corporations Act may be required or exemptions from the requirements to hold one or more of those licences; and measures to address the potential for market manipulation in relation to the short-term forward market would need to be considered further.

Given the benefits, the Commission considers a voluntary, contracts-based short-term forward market should be introduced into the NEM. The Commission considers that AEMO should undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market which would allow participant-to-participant trading of financial contracts closer to real time to provide the demand side with more opportunities to lock in price certainty.

4.1.3 Allowing consumers to access multiple FRMPs

The Commission recommends changes to regulatory framework to better enable consumers to access multiple service providers at a single connection point. It is envisaged that this would provide opportunities for consumers to access value from different parts of the supply chain, as well as supporting the integration of increasing amounts of distributed energy resources.

Currently, a consumer is only able to have a single FRMP at a connection point. This means that a consumer is only able to buy electricity from a single retailer at each connection point and to sell electricity or demand response to that same retailer at the connection point. This has the effect of bundling retail energy supply, wholesale demand response and energy

73 These legal considerations are discussed in section A.5.5.

exports from distributed energy resources such as solar PV together into a relationship with a single retailer. This recommendation seeks to expand the options available to consumers to engage multiple parties at a connection point for different services which would help with unbundling the above services.

Introducing multiple trading relationships would provide consumers with more choice to use energy when it is of value to them and reduce or alter consumption where the cost exceeds this value. Over time, this framework would facilitate the use of new technologies that allow for the least cost use of resources to meet consumer needs.

The Commission considers this change would provide consumers with greater opportunities to interact with the wholesale market and engage with a number of different service providers. It would also facilitate the integration of new dynamic and controllable resources in the wholesale market and provide increased opportunities for consumers to engage in demand response.

This would enable other sources of value to be accessed by consumers. Allowing consumers to access multiple service providers at the same connection point would support small generation aggregators and may allow regulatory frameworks to better accommodate orchestrated distributed energy resources (often referred to as a Virtual Power Plant) participating in the wholesale market.

It would also allow the regulatory framework to enable nascent developments such as the growing interest in electric vehicles. This recommendation could facilitate arrangements where a consumer is able to establish a separate retail relationship for their electric vehicle and maintaining their existing retail relationship. Implementing this arrangement would also allow for innovate approaches to retailing electric vehicle load to emerge.

The benefits that might be facilitated by allowing multiple parties to interact with a consumer behind the same connection point, shown in Figure 4.1 include more opportunities for demand side flexibility, distributed energy resources and peer to peer trading.

Figure 4.1: Possible benefits associated with this recommendation

Source: AEMC, *Multiple trading relationships - consultation paper*, July 2015, p. 19.

The Commission has previously considered a similar solution under the *Multiple trading relationships* rule change request.[74] However, it is worth noting that a number of aspects of the energy market have changed since we made a final determination for that rule change request, which we think translates to more benefits being realised from this option. This includes:

- the increasing uptake of distributed energy resources and improved technology
- a growing number of virtual power plants where distributed energy resources are being orchestrated to provide services on a wholesale level
- possible configurations of meters that would reduce the cost and complexity of accessing multiple FRMPs at a connection point[75]
- renewed stakeholder support.

74 See: https://www.aemc.gov.au/rule-changes/multiple-trading-relationships

75 For example, many distributed energy resources has in-built meters that are not able to be used as metering for the purposes of settlement under the current arrangements. However, if future regulatory arrangements permitted these meters to be used for settlements, this would likely reduce the implementation costs of this recommendation.

The Commission also recognises that there will be some costs associated with this recommendation. These include costs incurred by retailers and distributors in relation to changing IT systems and processes based around a one-to-one relationship between connection point, FRMP, NMI and metering installation. At the time of the *Multiple trading relationships* rule change request, distributors identified that breaking the one-to-one link between connection point, FRMP, NMI and metering installation would require a number of systems to be simultaneously overhauled due to the integrated nature of the systems. However, under the embedded networks framework, AEMO and distributors already need to account for multiple NMIs at a connection point, so the required systems changes may not be extensive.

A range of changes to metering and settlement rules and procedures would also be required, in addition to some potential changes to customer protection arrangements under the NERL and NERR.[76]

The changes being considered in this recommendation have the potential to raise further legal issues that would require further consideration. These issues may influence the complexity and cost of the changes being contemplated.[77] For example, these considerations include whether the obligations in the NERR remain appropriate following the introduction of multiple trading relationships. In particular, the NERL may require changes to avoid uncertainty regarding the application of the NERL, and to maintain consumer protections. This will in part depend on whether multiple trading relationships are permitted for all customer categories.

Due to the increased opportunities afforded to consumers, the Commission recommends that AEMO submits a rule change request to the Commission by end of 2018 to allow consumers to engage multiple service providers behind the same connection point. This would promote competition between retailers, support new business models and provide consumers with great opportunities to engage in demand response.

It is worth noting that AEMO and ARENA (in their joint submission to the directions paper of this Review) noted their intent to test this proposal through trials, to assist in a speedier implementation of any rule change made in relation to this. Trialling would present an opportunity to gather further information relevant to the costs and benefits as well as any technical complexity and provide valuable learnings for participants and stakeholders, as well as the Commission, in terms of implementing this option. We consider that these trials could be undertaken in parallel with the rule change request process with the intention of providing useful inputs as the detailed design of the mechanism is being developed and considered.

4.1.4 Allowing third parties to sell demand response in the wholesale market

The Commission considers that allowing third parties (participants who are not necessarily market customers) to sell demand response into the wholesale market could have benefits, including:

76 This is covered in more detail in Appendix B.

77 Legal considerations for this recommendation are explored further in section A.6.6.

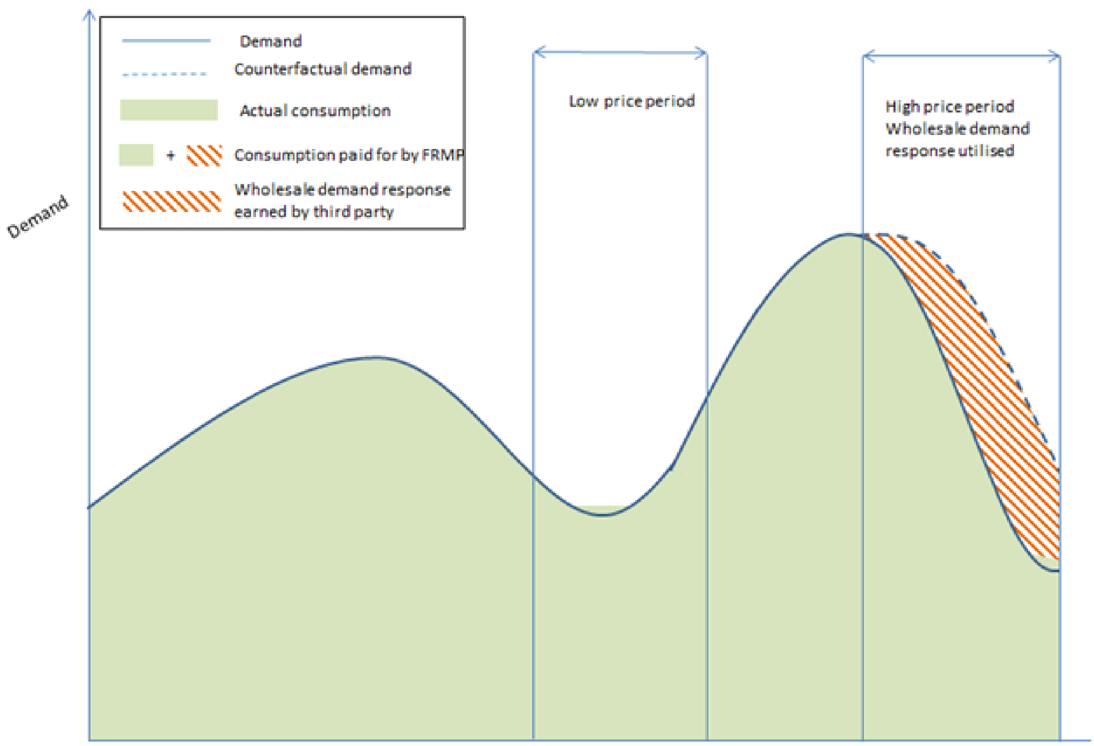
- improving the reliability of the power system
- providing greater transparency of the demand side to other market participants
- enabling active participation in determining outcomes in the wholesale market.

Figure 4.2 demonstrates how the value of demand response could be transferred to a third party. This example demonstrates a consumer reducing consumption during a period of high wholesale electricity prices.

In this figure:

- the underlying physical energy consumption is the green area, which the customer purchases from the retailer
- the striped area represents the amount of demand response - the customer purchases this quantity from the retailer and a third party 'sells' it into the spot market and pays the customer for the demand response
- the retailer would purchase the green *and* striped areas from the spot market
- if the customer offered demand response by shifting or deferring some consumption (rather than reducing overall consumption), the consumer would need to purchase that electricity from the retailer at the relevant time. This would be in addition to paying the retailer for baseline consumption while offering demand response (the striped area).

Figure 4.2: Transferring value of demand response



Source: AEMC

This approach would address a number of the challenges raised by stakeholders in relation to participating in demand response:

- It would allow a consumer to engage a third party for the sale of demand response services into the wholesale market and a retailer for a separate provision of retail energy to the consumer. The consumer would be able to change retailer without affecting its commercial arrangement with the third party.
- The third party would be able to sell demand response in the wholesale market without focussing on the typical role of a retailer in managing and hedging a retail portfolio. Instead it is able to focus on its core service provision.

A similar change was contemplated in the *Demand response mechanism and ancillary services unbundling* rule change.[78]

Under the current arrangements the supply of energy to a consumer is bundled with wholesale demand response. Retailers are incentivised to utilise demand response where it is efficient to do so; however, they may opt not to if they lack the experience or the organisational expertise to utilise wholesale demand response or do not expect to recover the costs of engaging with a consumer to provide wholesale demand response. In addition, retailer have other ways of managing wholesale electricity market price risks, such as financial contracts and vertical integration.

In addition, there are challenges for third parties looking to provide wholesale demand response. Third parties can only do so currently by either being a retailer themselves, or having a commercial relationship with a retailer.

This recommendation would address this issue by introducing a mechanism that would facilitate demand response from third parties in the wholesale market. This would allow demand response providers to be recognised on an equal footing with generators in the wholesale market.

The Commission considers that allowing third parties to sell demand response into the wholesale market could have a number of benefits including:

- Providing consumers with greater opportunities to participate in wholesale demand response by allowing additional parties to provide demand response and so promoting competition for these services. This would also have the effect of potentially decreasing prices in the wholesale market.
- Improving the reliability of the power system. In many instances, wholesale demand response can more efficiently contribute to reliability than building new generation. this is particularly true when a tight supply-demand balance is only forecast to occur for a short period of time.
- Providing greater transparency of demand side participation to other market participants, which will help market participants to make more efficient decisions in both operational and investment time frames on both the supply and demand side of the market.

78 AEMC, Demand response mechanism and ancillary services unbundling rule change, Final determination, November 2016.

However, there are also a number of costs or questions that are associated with this option. These include:

- determining an appropriate baseline methodology
- risks that may be imposed on parties not participating in demand response, depending on how the baseline was to be determined
- costs associated with system changes, including to AEMO's settlement systems
- costs associated with installing equipment or changing systems to schedule the demand response
- costs associated with applying this to aggregated small consumers.

In addition, a range of legal issues arise that require further consideration. These issues include:[79]

- whether retail contracts for demand response might constitute financial products
- maintaining any consumer protections and associated changes to the NERL or NERR
- changes to retail Renewable Energy Certificate liability.

Given these are not insignificant issues,[80] the Commission considers that these issues will need to be explored further.

However, there has been significant interest from multiple stakeholders - representing a range of industry participants - who have noted that they intend to submit a rule change request to the Commission to implement our a way for demand response aggregators to be treated on equal footing with generation i.e. implement a demand response mechanism. The Commission welcomes this - integrating demand response into the wholesale market is a critical component of facilitating the energy sector transition and so we do not consider there should be any delays in progressing this issue. If the Commission has not received a rule change request from one of these stakeholders by the end of August 2018, then it will draft a rule change request that the Energy Security Board can submit.

In addition, AEMO and ARENA will be trialling in-market demand response. The objective of this trial is to demonstrate the potential to increase wholesale market competition by improving access of demand-side resources to spot market pricing. Under the trial, demand response would be provided to the spot market by the customer / aggregator which displaces the energy which would otherwise have been provided by the marginal generator. As an in-market trial, the majority of the revenue would be earned in the spot market, paid for by retailers and dispersed to demand response providers through the market settlement system.

This will be beneficial since some of the policy decisions on these aspects can be tested and informed through practical trials, rather than solely theoretical considerations. For example:

- how can the demand side best be scheduled in the wholesale market?
- which entities should be responsible for setting the baseline?

79 These legal issues are discussed in more detail in section A.7.6.

80 These issues are explored in Appendix A.

- how would this mechanism coexist with other demand response initiatives underway and impact on other market participants?

As such, the Commission is proposing that these in-market trials of demand response take these considerations into account.

4.2 Retailer self-forecasting

The directions paper presented an option whereby market customers (in this section referred to as retailers) would provide forecasts of their own load to AEMO to be used in place of centralised forecasts in the short-term (i.e. ST-PASA, pre-dispatch and dispatch).

The Commission has progressed its thinking on this is option and finds that:

- On the matter of retailer self-forecasting, this approach should not be pursued at the current time. Rather, issues associated with DER visibility should be pursued through ongoing AEMC and AEMO projects, and other industry initiatives.

The Commission's rationale and analysis on this matter are set out below.

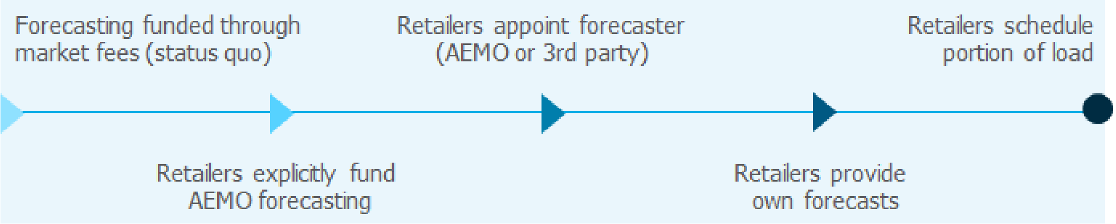
4.2.1 Potential rationale for this option

The rationale for such a major change in the context of this reliability review would be to achieve greater visibility over the operation of distributed energy resources (including demand response) in order to improve forecast accuracy. As discussed in Chapter 3 of this report, forecast accuracy affects the ability of AEMO and market participants to make efficient operational and investment decisions, such as when to prepare a unit to generate, or when and how to intervene in the market. In turn, these decisions impact on the reliability of the power system.

The retailer forecasting option is an alternative (or, potentially, a complement) to enhanced obligations on DNSPs, retailers and aggregators to provide system operators with static and dynamic data on distributed energy resources. For instance, if retailers have visibility over the distributed energy resources that their customers have deployed, and can provide a reliable forecast, the level of detail required to be reported to the system operator could be reduced. This arrangement could be more efficient if retailers are able to provide a more accurate forecast, or a similar quality forecast, at lower cost.

The Commission views this option as a stepping stone from centralised forecasting by the system operator, to the scheduling of some portion of retailers' loads. A possible pathway is depicted in Figure 4.3 below.

Figure 4.3: Possible pathway from centralised to decentralised forecasting



The steps of the possible pathway are:

1. Allocating the financial responsibility for demand forecasting to retailers serving non-scheduled load. The rationale for this is that these costs effectively represent the costs of the non-scheduled load participating in the market. Similar to how supply side participants cover the costs of their participation in the market (i.e. through the assembly of trading and risk management teams, IT systems, internal governance structures), it would be appropriate for demand side participants to face these costs directly. This provides retailers with a sharper price signal to consider when making decisions around how to participate in the market.
2. Allowing retailers to collectively appoint the forecast provider. In step 1, retailers directly face the costs of demand forecasting but do not have the option to choose how or by whom it is undertaken. This changes in step 2, allowing retailers to make the trade-off between forecast accuracy and the cost of the forecasts being provided.
3. Retailer self-forecasting. This step involves retailers providing a forecast of their own load to AEMO. This could provide a greater incentive for them to seek out more opportunities to monitor and control, with consent, the load of their customers. These decisions, such as whether to call upon demand response capability, are expressed through the load forecast, providing useful information to AEMO and the rest of the market about the residual load that needs to be met from other sources (or interventions).
4. Scheduling of retailer load. Once retailers have more visibility and control over customer load then it may be feasible for them to schedule a portion of it. Scheduling allows for more explicit participation than in step 3 as a price would be submitted for different consumption levels and the dispatch engine would issue instructions for load to be turned up or down in accordance with price preferences. These bids would be able to set the spot price, unlike in step 3. At step 4 there would be an explicit two-sided market with much more even participation by the supply and demand side participants.

The logic for retailers to provide load forecasts to AEMO is that their exposure to spot prices already provides an incentive for retailers to produce accurate forecasts of their own. If a retailer under forecasts, then they risk not having contracted for enough risk management products and therefore being exposed to very high spot prices. Conversely, a retailer that over forecasts customer load and buys too great a volume of risk management products will also likely be at a financial disadvantage to a retailer that has forecast more accurately.

Further, retailers are well-placed to forecast customer load as they have existing commercial relationships with consumers and access to their data. An obligation for retailers to forecast load could potentially provide a greater incentive for them to seek out more opportunities to monitor and control, with consent, the load of their customers.

Network businesses may also be able to provide useful insights about the operation of distributed energy resources, and may have entered into network support agreements in some instances. To the extent that network businesses have access to different or more complete data, there could be scope for retailers to access this for forecasting purposes, subject to considerations around customer consent and privacy. This is not to preclude networks from participating in forecasting processes in other ways – AEMO could still request information from them directly. However, in the context of a retailer self-forecasting obligation which leverages their existing incentives to forecast accurately, it would be logical for retailers to decide, and put a value on, the information that network business could potentially provide to them to improve their forecast accuracy. This could result in retailers paying network businesses for information services, if retailers decide that the value to them is greater than the price of it being provided.

4.2.2 Stakeholder views

The feedback we received on the directions paper indicated that there was only limited stakeholder support for the option of retailer self-forecasting. The issues identified primarily related to the scale of the change, its cost, and whether it would be an effective incentive mechanism for retailers.

Those questioning its effectiveness cited that retailers are not the sole providers of DER resources and demand response services; network businesses and other services providers also provide signals to curtail load and operate DER resources such as energy storage. In such instances, retailers may not be capable of providing an accurate forecast.

Others questioned how the price that retailers would pay, or be paid, for the differences between forecast and actual demand values would be calculated (see options discussed in section 4.2.3 below). The AEC noted that administrative penalties for forecast errors would be required since the NEM does not have multiple settlement passes. It was generally considered that retailer forecasting should only be pursued if other options to improve forecast accuracy prove ineffective.

4.2.3 Commission's analysis and findings

In response to this stakeholder feedback, the Commission considered instances in other electricity and gas markets where retailers are required to provide forecasts of their expected load. As identified by the AEC, this approach to forecasting is most common in markets that have multiple settlement passes (i.e. day-ahead settlement and real-time settlement). In the US-style ahead-market, a participant (generator or load) that does not meet its day-ahead commitment is effectively required to buy or sell energy at the real-time price. A retailer that overestimates its demand is required to pay the difference between the day-ahead and real-time prices for the deviation volume, in most cases inflating the volumetric cost associated with serving the actual load. In this way, an ahead market explicitly values participant forecast accuracy and cost of deviating from the day-ahead settlement quantities.

A similar approach is used in the Victorian Declared Wholesale Gas Market: participants forecast their uncontrollable withdrawals,[81] which are subject to rebalancing four times over the gas day. A participant's deviation volume is charged at the price when the market is next rebalanced.[82] Similar to the US-style ahead-market, the payments for deviations are reduced through accurate forecasting. However, a point of difference is the frequency of the rebalancing – gas markets can be rebalanced less frequently as gas injections and withdrawals do not need to balance in real time.

In the absence of multiple settlement passes in the NEM, it would be necessary to take an administrative approach whereby differences between forecast and actual volumes are charged at a value which could be derived from the prevailing spot price. For example, forecasting errors could be charged at a premium to the spot prices (perhaps, 120 per cent of the spot price). Variations of this approach exist in European electricity markets, where deviations in a participant's net physical and financial position are charged at the balancing energy price. Generally, such approaches are likely to be less efficient than a US-style ahead-market due to the difficulty in designing a price signal that promotes both accurate forecasting and efficient demand response decisions. Unlike the ahead-market, an administrative approach would almost inevitably produce penalties that are too high in some situations, and too low in others.

Due to the complementary reforms that would be required to implement a US-style ahead-market, the Commission considers that implementing retailer forecasting at the current time is unlikely to result in more efficient market outcomes than the status quo. Instead, DER visibility, control and optimisation issues should continue to be considered through AEMO and other AEMC projects. These include the AEMC's annual *Electricity network economic regulatory framework review*, and the AEMO-ENA *Open Energy Networks* consultation.[83]

The *2018 Electricity network economic regulatory framework review* final report observed that there are opportunities for network businesses to take actions to enable DER to provide more value to customers. The Commission considered that there are a number of 'no regret' first steps that distribution businesses can take now. These involve building a better understanding the impacts of connecting higher levels of DER to their networks and the network constraints that may emerge as a result. The 2018 final report also identified efficient integration of DER as an area of focus for future reviews.[84]

A further course of action to accelerate the process identified in Figure 4.3 above could be to move directly to the load scheduling option. This could be achieved through a rules obligation on retailers to offer a portion of their customer demand as scheduled load that must be bid into the market at or below the market price cap ($14,500/MWh in 2018/19). There would be

81 Uncontrollable withdrawals are the quantities of gas that participants withdraw regardless of the market price. This includes almost all customers in the residential, commercial and industrial sectors, as well as demand from gas-fired generation.

82 AEMO, *Guide to Victoria's Declared Wholesale Gas Market*, February 2012, pp. 9-12.

83 AEMO and Energy Networks Australia 2018, *Open Energy Networks*, consultation paper.

84 AEMC, *2018 Electricity network economic regulatory framework review*, 28 June 2018 , Sydney.

a process to determine the required quantity of scheduled load, such as calculating it as a percentage of regional peak demand. For example, the requirement could be for every retailer to schedule a volume of load that is equivalent to 5 per cent of their contribution to peak demand.

It is expected that this arrangement would encourage the deployment of load control equipment, and associated retail offerings for customers that are included in a scheduled load tranche. As the scheduled load must be bid at or below the price cap, in extreme events it could fail to be dispatched and would need to be curtailed (else, the market participant would face compliance action for not complying with its dispatch instructions). So long as the value that the scheduled load customers attribute to consuming electricity is less than the market price cap, this option could present an efficient option for the management of reserves under extreme conditions.[85]

Clearly, retailers would face costs to the extent that their existing portfolio of demand response capacity is less than the volume required to be scheduled. New equipment would likely need to be deployed to meet the requirements of bidding as a scheduled load. These costs would need to be viewed in the context of the costs associated with alternative options (i.e. the RERT) and the broader benefits possible from the more transparent participation of demand side resources. While the Commission is not proposing that this option be implemented at the current time as it is unlikely that the benefits would outweigh the costs, it encourages retailers to explore ways in which that can play an increased role in the development of the two-sided wholesale market.

FINDING

Implementing retailer forecasting at the current time is unlikely to result in more efficient market outcomes than the status quo. instead, DER visibility, control and optimisation issues should continue to be considered through AEMO and other AEMC projects. These include the AEMC's annual *Electricity network economic regulatory framework review*, and the AEMO-ENA *Open Energy Networks* consultation.

85 In practice, a customer is likely to have entered into a commercial arrangement with a retailer whereby they can be asked to curtail, or vary in some other way, their consumption. In this way, the retailer could be seen to be making a decision about the value of consuming, or not consuming. However, for this to be efficient, the threshold at which consumption is to be reduced must be determined by the value that an individual consumer derives from consuming electricity.

5 IMPROVING WHOLESALE MARKET OUTCOMES

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 in the NEM. Market participants make investment and operational decisions based on these market signals. Prices in the spot and contract markets provide signals for adequate generation and demand-side resources to be built and dispatched, as well as information about the balance of supply and demand across different places and times.

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

The most critical thing to recognise is that, in the NEM, competing businesses make investment and operational decisions since they can mitigate risks associated with these decisions as well as have incentives to improve risk management over time. The framework provides incentives for an efficient mix of technologies to be deployed - for example, expectations of highly volatile supply and demand conditions translate into expectations of highly volatile spot market prices. The degree of volatility affects the demand for and value of hedge contracts such as caps and swaps. In turn, this provides incentives for investment/retention of plant best able to capitalise on that volatility, such as peaking plant and storage solutions.

Similarly, the proposed National Energy Guarantee, and in particular, the reliability requirement of the proposed policy builds on existing spot and financial market arrangements in the electricity market to facilitate investment in dispatchable capacity.[86] In other words, the Guarantee will also contribute to improved wholesale outcomes in the NEM.

Given the importance of the wholesale market to the reliability frameworks, in this chapter we provide an overview of how we consider that the existing wholesale market outcomes in the NEM could be improved, in order to assist in maintaining and promoting reliability outcomes in the NEM.

5.1 South Australian market

In the Directions Paper, the Commission noted that AEMO was in the process of identifying the existing ahead features of the NEM that may require change and compiling evidence of the deficiencies that it considers need to be addressed, either through targeted improvements to existing arrangements or through a centrally facilitated ahead market design. This is being drawn from the South Australian experience.

86 See the draft detailed design of the Guarantee here http://coagenergycouncil.gov.au/publications/energy-security-board-%E2%80%93-draft-detailed-design-national-energy-guarantee-consultation

Since that time, AEMO have progressed their work and presented some initial views to our technical working group on issues they are observing in operating the South Australian market. AEMO has observed that:

- South Australia's network is experiencing low system strength, inertia and higher reliability risks as synchronous generation has been displaced by renewable energy.
- It is currently intervening frequently in South Australia by directing synchronous generators to stay on to provide system strength. There are concerns that in the near future AEMO might need to frequently direct plant for reliability as well.
- AEMO, via the direction process, is intervening regularly in South Australia. The direction process can cause disruption to generators' maintenance schedule, which could reduce their performance quality and reliability in the long term. Having a formal market mechanism to provide the desired outcome could potentially lead to both operational and long-term efficiency gain. For these reasons AEMO have used this as a case study for their work.

To date, given the system security issues of low system strength are manifesting in real-time outcomes for the SA network, AEMO has focused on identifying and exploring these issues. This has included summarising current technical issues with operating the transmission network in South Australia, identifying what was involved in intervention events, investigating the appropriate strategies to manage those issues, and evaluating the costs and risks that may emerge from those strategies.

The AEMC looks forward to continuing to work with AEMO to investigate the issues being observed and consider the changes to the regulatory and market arrangements that may be necessary in both the short and then longer term that are effective and least cost and, to the extent relevant, in other jurisdictions.

5.2 Dispatchability, flexibility and ramping

For an electricity system to work properly and contribute to reliability, supply must equal demand plus reserves (near) instantaneously. As supply or demand changes, for example, due to changing levels of consumption or output of generators, the rest of the system must respond to maintain the balance of supply and demand.

Achieving a balance of supply and demand may be more challenging in the future due to an increased penetration of variable renewable generation in the system and a more responsive demand side of the market, as discussed in chapter 4. This is because it may result in:

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

unexpected decrease in demand. Again, the remaining system must collectively be able to change its supply and demand in response in order to maintain reliability. Some commentators have suggested that the existing market arrangements may not address these challenges in the future. Put another way, they have suggested that there may in the future be insufficient dispatchable or flexible generation or load to balance supply with demand as that balance changes unpredictably or rapidly.

Given this transition, as well as the fact that in the NEM, the 5-minute spot price provides a signal of the value of energy during *that* five minute interval, in and of itself, the 5-minute spot price provides limited indication of the value of energy in the future. This has led some commentators to assert that there is no transparent and explicit value for reserves, flexibility or dispatchability in the NEM, and that as a consequence these characteristics are not (or will not be in the future) sufficiently valued or provided.

BOX 3: WHAT ARE DISPATCHABILITY AND FLEXIBILITY?

The terms 'dispatchability' and 'flexibility' are not defined in the regulatory framework for the NEM. Broadly:

- **Dispatchability** refers to sources of energy or load that can respond to instructions to increase or decrease output or usage. Resources that are dispatchable are valuable in that they can maintain the balance of supply and demand because their output can be instructed to adjust in response to changing conditions.
- **Flexibility** refers to the ability for generation or load to respond to changes in demand and supply in a timely manner. Resources that are more flexible are more valuable in maintaining the balance of supply and demand because they can adjust more rapidly to changing conditions than less flexible generators and load.

However, precisely defining dispatchability and flexibility is difficult. For example, one generating unit may be able to adjust its output more than another over a relatively long time period (say, 3 hours) but less over a relatively short time period (say, 5 minutes). Also, some generators are dispatchable when they decrease their output but not when they increase their output - how controllable must a resource be to be considered dispatchable? This demonstrates that there are many contradictions and trade-offs that exist in these concepts. Creating definitions of flexibility and dispatchability that do not take into account the various trade-offs and complications is likely to result in too narrow definitions that could create perverse incentives.

In contrast, ramping is a concept defined and used already in the NEM. The NER defines ramp rate as: "the rate of change of active power (expressed as mw/minute) required for dispatch". Clearly, this is a related concept to both dispatchability and flexibility, for example:

- more flexible generators/scheduled load have a higher ramp rate than less flexible generators/scheduled load
- generators/consumers that are not dispatchable cannot respond to instructions to change their power output/consumption.

Ramp rate constraints are factored into the dispatch optimisation process that is in use in operation of the wholesale market. For example, generators can reduce their ramp rates to reduce the possibility (or the magnitude) of an increase in output.

We have considered the above, and have three findings with respect to the value of dispatchability, flexibility and ramping in the spot market:

1. the spot and contract markets currently provide incentives sufficient for the efficient provision of dispatchable and flexible generation and load, in both operational and investment timescales
2. our analysis of ramping data suggests ramping capability is sufficient now and in the immediate future
3. ramping markets in CAISO, MISO and Eirgrid appear to have been necessary to correct features of their market design that leads to inadequate compensation for ramping; features that do not apply in the NEM.

However, despite these findings, we recognise there are factors outside of the spot and contract market both inside and outside of reliability frameworks that may distort the existing incentives. Consequently, the Commission is taking steps both as part of the AEMC's reliability program to consider these distortions further. In particular, as noted above, AEMO and the AEMC will continue to work together to progress consideration of issues being observed in the South Australian market.

These findings are explored in more detail below. Appendix B provides a comprehensive outline of the Commission's findings.

We also note that balancing supply and demand in timescales much shorter than five minutes is the domain of frequency control ancillary services and is not in scope of this review - we are considering these issues through our *Frequency control frameworks review*. For the purpose of this review, we are interested with the rate of change of supply (and demand) – ramping – over time periods greater than or equal to five minutes.

5.2.1 Incentives for dispatchability and flexibility

Theoretical incentives for dispatchability and flexibility

We consider that dispatchability and flexibility are already sufficiently recognised and rewarded in the spot market.

Consider what happens when there is a sudden and unexpected tightening of supply and demand, leading to a corresponding increase in prices in the energy market. Those generators that are able to adjust their supply upwards deliberately and quickly will be rewarded for doing so through higher prices received for their generation output. Similarly, those generators that are able to deliberately adjust their output down are able to avoid incurring losses when prices suddenly and unexpectedly fall below their short run costs.

Generators that are less flexible or cannot actively respond to changes in the spot price, at times, stand to bear an actual or opportunity cost if they are slow moving.

These incentives in operation also flow through to efficient investment decisions. Expectations of the market not delivering sufficient flexible or dispatchable plant will translate into expectations of an increased frequency of high price spike events. This in turn provides incentives for market participants to invest in flexible and dispatchable generation capacity (or demand response) capable of taking advantage of these typically fleeting high prices.

The incentives provided through the wholesale spot market for the provision of dispatchability and flexibility are framed by the reliability settings. Rewards for being flexible and dispatchable are capped at the market price cap while losses for being inflexible or non-dispatchable are capped at the market floor price.

While there is no transparent and explicit value for flexibility and dispatchability in the NEM, binding ramp rate constraints do cause spot prices to be higher or lower than they otherwise would be. Therefore, the lack of an explicit value for flexibility and dispatchability that is separate from the energy price does not of itself necessarily lead to the conclusion that these are (or will be) under-valued or underprovided.

Further, market participants take account a number of factors when making their commitment decisions through their bids. These factors influencing unit commitment decisions made by market participants include:

- their estimation of the likelihood of spot prices being at a variety of levels in the future (i.e. their probability-weighted expectation of future spot prices)
- their sold contractual position and their aversion to making potentially large losses through their contracts if not also generating when the spot price is high
- their ability to ramp generation from a variety of operating states in order to maximise their output to capture high spot prices and minimise their generation to avoid spot prices below their costs
- any fixed costs associated with starting and stopping units, as well as the costs associated with running the units (for example, at minimum output).[87]

These factors should lead market participants to focus further ahead than just the next five minutes – the prospect of potential high spot prices in the future provide incentives for market participants to structure their bids so as to commit units ahead of time and hence provide reserves to the market. This is the case even if the market participant makes a loss during any individual 5-minute interval (or indeed a number of successive 5-minute intervals). This thinking is supported by our analysis on this, presented below in section 5.2.2.

As market conditions change, market participants' probability-weighted expectations of future spot prices change. For example, the high prevalence of variable renewable energy sources may serve to depress spot prices at certain times. However, it will also increase the likelihood of very high spot prices, for example, when supply provided by variable, renewable energy

87 Market participants may also factor in the prospect of being directed by AEMO, and hence receiving compensation.

resources unexpectedly and rapidly drops off. This should influence unit commitment decisions of other generators.

Some commentators have suggested that the unit commitment decisions taken by individual market participants may be inefficient and that as a result, dispatch is inefficient. They suggest that instead, unit commitment decisions should be centralised and a US-style ahead market introduced. Our analysis as well, as feedback from stakeholders, has found that this is not likely to be the case. This is discussed further below, and in appendix B for further details.

All this demonstrates that the process of optimising dispatch is therefore a complex one, not solely undertaken through the NEM dispatch engine in real time, but also by market participants through an iterative process. It is through this iterative process that unit commitment and dispatch optimisation occurs over time periods longer than a single five-minute interval.

Potential practicalities that may influence the above incentives

However, despite our findings, the Commission also found a number of possible sources of distortions to the market, including:

- An inappropriately low market price cap (or other reliability settings). This would cap the reward for dispatchable and flexible generation in the event of price spikes resulting from rapid or unexpected changes in supply and demand. An increased abundance of low short run marginal cost generation may result in a decrease in typical prices, which in turn may require a high market price cap to allow other generators to recover their costs when price spikes occur. However, as noted above, the Reliability Panel has recently undertaken extensive analysis of these settings and concluded that there current values are appropriate at present.
- The relative size of generation units in comparison to regional demand. For example, in South Australia, where demand is relatively low, an individual generating unit may be large enough that committing the unit causes low prices and an excess of reserves compared to efficient levels, but not committing results in insufficient levels reserves provided to the system. This inability to “fine-tune” via unit commitment may mean that market participants, acting on their own incentives, provide insufficient reserves.
- Interventions by the system operator in the wholesale market for reliability reasons. As discussed in chapter 6, interventions are an appropriate last-resort mechanism to maintain reliability. However, as also discussed in that section, the actual or prospective changes to financial outcomes for market participants as a consequence of intervention may serve to distort the price signals provided by the spot and contract market. This may in turn lead to inefficient operational or investment decisions. As a result, intervention mechanisms need to be designed to minimise distortionary effects.
- Interventions by the system operator in the wholesale market for system security reasons.
- Uncertainty regarding emissions reduction policy, which in turn influences the market participants’ expectations for the future need for dispatchable and flexible

generation/load. As noted above, proposed National Energy Guarantee should provide policy certainty regarding an emissions reduction mechanism that is effectively integrated with the electricity market.

- Prospective investors in new generation may also be disconcerted by the increasing role of the state and Commonwealth governments in funding, subsidising or studying the feasibility of additional dispatchable generation capacity. Private investors may be less inclined to invest in new generation for fear that their returns could subsequently be truncated by government-sponsored initiatives.
- Insufficient levels of competition in the wholesale market. The final report of the ACCC's Retail Electricity Pricing Inquiry notes that market concentration in the NEM has increased and expresses concern that this would be significantly affecting bidding behaviour in the NEM, which could lead to prices above efficient levels.[88] The report also makes a number of recommendations to deal with market concentration and boost competition in generation and retail markets.[89]

We will be working together with AEMO to consider whether these distortions are "real" (i.e. observed in practice), in the context of issues being observed in the South Australian market.

5.2.2 Analysis of ramping requirements and capability

The Commission undertook initial quantitative analysis of ramping data to examine whether, despite the theoretical conclusions, dispatchability and flexibility are valued in the NEM. Appendix B sets out these findings in detail. Our findings are summarised as follows:

- There is limited evidence that the increase in renewable penetration is leading to an increase in the demand for ramping at the extremes. More importantly, there appears to be an abundance of ramping capacity available in regions of high renewable penetration.
- It appears to follow that there is currently no shortfall, or gap in ramping capability, that is not being met by the market.
- Our analysis also indicates that high demand for ramping (on a 5-minute basis) in South Australia is positively correlated with high prices. Many of the extreme outcomes stem from off-peak hot water load that occurs late at night, a phenomenon that has been present in the South Australian market for a long time. These findings suggest the market is already providing price signals for ramping and has been doing so for many years.

Our analysis focussed on historical outcomes. We did not attempt to predict future outcomes but the results demonstrate that, to date, there has neither been a demonstrated shortage of ramping in the NEM, nor is there likely to be in the near future. This is because the analysis shows that there is surplus ramping capacity (i.e. ramping capacity is excess of what is demanded) that currently exists in the market and so we would expect this to continue for several years in the future.

88 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

89 Ibid.

5.2.3 Ramping markets overseas

Based on our analysis to date, there is likely to be adequate ramping availability. However, it is informative to understand why overseas markets have introduced ramping products.

These overseas markets are grappling with similar issues as those being considered in this chapter; i.e. concerns about dispatchability and flexibility in light of an increased penetration of variable renewable generation. A number of other markets have introduced products that explicitly reward ramping capability. The Commission has examined ramping products of three overseas markets (California, the mid-west of the USA and Ireland) to consider whether the problem and the product are applicable to the NEM.

The result is that the Commission does not consider the ramping products it has investigated are appropriate for the NEM, for two reasons:

- The California and the mid-west ISOs identified the need to procure ramping products primarily because they procure ramping capability over two dispatch intervals and this sometimes means they have to pay generators to be constrained off in the first interval in anticipation of future ramping requirements.
- The Irish market has a market price cap of €1,000 (~$1,500), almost an order of magnitude less than the market price cap in the NEM ($14,500/MWh). This means that in Ireland, generators' weighted average expectations of future prices may be less than those required to provide sufficient ramping capability to the system in operational and investment timescales.

From observing markets overseas and for the purpose of this report, the Commission defines a ramping product as an explicit product sold by a provider of ramping capability. the buyer of a ramping product is typically the system operator. Again, by "ramping capability", we mean the ability to quickly and controllably adjust generation or load up and/or down over a period of time equal to or greater than the dispatch interval (i.e. 5 minutes, in the NEM).

A ramping market is the mechanism through which ramping products are procured.

Investigation of Californian and Mid-west ramping products

The Californian energy market is operated by the California independent system operator (CAISO). The Midcontinent Independent System Operator (MISO) is the system operator for the electricity market in the Midwest of the United States, parts of the southern United States, and Manitoba, Canada.

Both of these Independent System Operators (ISOs) recently introduced ramping products (MISO in April 2016[90] and CAISO in November 2016[91]) to address a problem that is broadly the same in both markets. For that reason we discuss both products together.

Appendix C.4 describes the problem and how the ramping market operates using a simple hypothetical example. We found that, unlike the NEM, both ISOs employ a dispatch engine

90 RTO Insider, *MISO seeks to Launch Ramp Product April*, https://www.rtoinsider.com/miso-ramp-product-april-1-21339/, 18 January 2016.

91 CAISO, *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, http://www.caiso.com/Documents/FlexibleRampingProductuncertaintyCalculationimplementationissues.pdf, 18 April 2018.

that seeks to minimise the aggregate cost of generation over two dispatch intervals. This means that, where it is economic to do so, ramping required for the second dispatch interval can be procured from the first interval by constraining down non-marginal generators that would otherwise be dispatched at maximum output and constraining up the generator at the margin to make up the difference. This dispatch outcome provides "headroom" for the non-marginal generators to ramp up in the subsequent interval to avoid the need to dispatch a higher cost generator. However, constraining down those generators in merit order to boost ramping capability in the second interval reduces the revenues those generators would have otherwise earned in the first interval. This weakens the signal to invest in higher ramping capability.

The rationale for this ramping product therefore does not appear relevant in the current NEM design. It would only become relevant if the NEMDE was changed to optimise over multiple dispatch intervals, which would require changes to the NER as well as AEMO processes.

Investigation of Irish ramping products

in 2013, Eirgrid[92] undertook an exercise to model the 2020 power system with specific focus on the likely system scarcities that would arise in the power system (reserve, inertia, reactive power, ramping) given forecasted revenue streams of generation based on the revenue streams available at the time (energy, capacity and ancillary services). The results of the analysis found that there was not sufficient revenue streams or market signals available to the overall generation portfolio to meet the system scarcities identified – of which ramping capability was one of these scarcities.[93]

On this basis, Eirgrid introduced three ramping products, as outlined in Table 1.1 (below).

Table 5.1: Eirgrid ramping products

PRODUCT	RAMP-UP REQUIREMENT	OUTPUT DURATION
Ramping margin 1	1 hour	2 hours
Ramping margin 2	3 hours	5 hours
Ramping margin 3	8 hours	8 hours

Ramping margin is defined by Eirgrid as the guaranteed margin that a unit provides to the system operator at a point in time for a specific horizon and duration. Ramp-up requirements refers to the time it takes for the ramping product to reach its required output; output duration refers to the length of time that the output must be maintained for.[94] Eirgrid and SONI (the transmission system operators for the Republic of Ireland and Northern Ireland, respectively) procure these products. A regulated tariff is paid by them (and recovered from

92 Eirgrid is the transmission system operator for the Republic of Ireland.

93 Ibid.

94 Eirgrid, System services portfolio capability analysis, see: http://www.eirgrid.ie/site-files/library/eirGrid/Ds3-system-services-Portfolio-Capability-analysis.pdf.

transmission use of system charges) to all technically eligible service providers for the quantity of the service required.

The Commission notes an important difference between the design of the island of Ireland's energy market in comparison to the NEM. The Irish market has a market price cap of €1,000 (~$1,500), an order of magnitude less than the market price cap in the NEM. This means that in Ireland, generators' weighted average expectations of future prices may be less than those required to provide sufficient ramping capability to the system in operational and investment timescales. As noted, the Commission's conclusions about dispatchability and flexibility in the NEM are predicated on the market price cap being sufficiently high to provide sufficient incentives in operational and investment timescales.

5.3 Considering the suitability of day-ahead markets in the NEM

Another option that has been mentioned that could potentially assist with the transition occurring in the wholesale market is the introduction of a day-ahead market. In particular, the Finkel Review recommended that:

> By mid-2018, the Australian Energy Market Operator and the Australian Energy Market commission should assess: [...] the suitability of a 'day-ahead' market to assist in maintaining system reliability.

A centrally-facilitated ahead market could be designed to achieve a number of alternative objectives. The objective of any such design focuses on how existing arrangements might need to change, and the nature of deficiencies in the existing market in relation to each particular objective that could be addressed. It is also important to understand what part of the existing market design may no longer be serving its purpose, and articulating the materiality causes of such an issue, is necessary in order to work out what is the best solution to address the deficiencies.

5.3.1 What are the current ahead features in the NEM?

The NEM, despite not having a formalised day-ahead market, has many features which play a similar role to that of a day-ahead market. These features include information that is provided to AEMO as part of the pre-dispatch process, supported by a liquid financial derivatives market with rebidding down to five minutes before real time. Rebidding allows participants with the flexibility to adjust their position in response to new information as it becomes available including changes in market conditions as well as responding to offers or bids of other participants.

Rebidding allows participants with the flexibility to adjust their bidding position to respond to new information as it becomes available including changes in market conditions, conditions relating to the generating unit or its fuel supply, network constraints as well as responding to offers or bids of other participants, as would be expected and necessary in a workably competitive market.

The practice of rebidding reflects the iterative process undertaken where generators reflect their intentions and physical condition of their plant through their bids. The widespread nature of the practice also implies that market participants continually re-optimise their own portfolios in response to new information and reflect this through adjusting their bids.

Box 4.4 of the directions paper provided details of the incidence of rebidding in the NEM. It showed that, while the trend in rebidding between 2007 and 2014 was downward, rebidding was still widely used and is an important mechanism for responding to changes in expectations and real-time events as they unfold. This allows for the most up-to-date information to be incorporated into dispatch outcomes.

The decision to allocate to market participants both the decisions to commit units and the associated risks was a deliberate one when the NEM was established. This was because market participants, as described above in section 5.2 have the appropriate information and financial incentives from the spot and contract market to make these decisions. And, as market conditions change, unit commitment decisions of participants change to reflect these. The historic low level of unserved energy in the NEM is evidence of this.

The above section focussed on operational decisions. However, similar arguments can be made with regard to investment decisions. The market provides incentives for investment in not only the correct quantity but also the appropriate type of generation capacity and potential demand response. Commitment decisions can be influenced by the ability of plant to ramp quickly and the costs associated with committing and de-committing units. Those types of generators that are able to ramp quickly will incur fewer losses (or opportunity costs, depending on their contractual position) in the event that prices are high and they are not available, because they will be able to quickly commit. The time period over which they were unavailable is short.

Similarly, those generators which are able to be committed at very low cost will be more profitable than those with higher commitment costs. This in turn improves the business case associated with investing in these types of generators, including through reducing the risk associated with entering into contracts for a large proportion of their capacity.

The introduction of five-minute settlement will further sharpen the incentives to make investment and operation decisions consistent with the needs of the system, while the proposed National Energy Guarantee should provide policy certainty regarding emissions reduction and so improve investor confidence.

5.3.2 What are the types of day-ahead markets?

There are a number of options for the design and implementation of day-ahead markets. Through this Review we have considered two common designs:

- a European-style ahead market that facilitates participant-to-participant trades ahead of real-time
- a US-style ahead market that facilitates participant-to-system operator actions as a tool to schedule reliable operations.

The Commission considers that a European-style ahead market, or a voluntary short-term forward market, could have benefits in the NEM, particularly for the demand-side, with this discussed in chapter 4 and appendix A.

In contrast, the introduction of a US-style market was found to be more complex and would require significant consideration of the associated costs and benefits in order for it to be considered to promote the National Electricity Objective.

Our directions paper focussed on US-style ahead markets and identified three potential objectives this type of ahead market could be designed to achieve in order to assist with both reliability and security outcomes in the NEM. The objective of an ahead market is important as it will inform the design of such a market. The three objectives identified in the directions paper were:

1. to provide market participants (both supply and demand side) with more, or better quality, information so that they can incorporate this information into their unit commitment and demand response decisions and bids/offers and therefore increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.
2. to provide the system operator with more, or better quality, information so that the system operator can use the information to manage the system in relation to reliability and security outcomes.
3. to provide the system operator (rather than participants) with a schedule that centrally coordinate unit commitment decisions, the intent being to increase the efficiency of outcomes in the NEM wholesale market, including in relation to reliability and security outcomes.

These three objectives exist on a spectrum, with the first objective being most closely aligned with the current NEM arrangements and the third objective being the biggest departure from the current market arrangements.

5.3.3 Commission's analysis and conclusions

Appendix D details these objectives and the following analysis and conclusions more comprehensively.

<u>Objective 1 – providing better information to market participants</u>

The current arrangements in the NEM provide market participants with large amounts of information from numerous sources. In addition, there are a number of more targeted changes that could be made to the current processes to provide the market with information. A number of recommendations to improve information provision in the NEM are discussed in chapter 3.

The Commission also notes that a short-term forward market, which is discussed in more detail in Appendix A, may be an alternative to a formalised ahead market that would also achieve the objective of providing the market with better information and price certainty.

The Commission does not consider that an ahead market with the objective of providing market participants with greater information is required to improve reliability outcomes in the NEM at this time. However, there may be some benefit associated with the introduction of a voluntary, contract-based short-term forward market in the NEM. The case for a short term forward market is discussed in more detail in Appendix A.

Objective 2 – providing better information to the system operator

The second objective discussed in the directions paper also related to information provision but this time it concerned the information that is provided to the system operator. This objective is framed around facilitating transparency of information to the system operator so that the system operator can better manage the system in respect of reliability and security.

The extent to which an ahead market could reduce the number of out-of-market actions by the system operator is not clear at this stage. A number of potential deficiencies with, or required improvements to, the current market design would need to be identified to provide evidence to support this claim. These would include:

- The current pre-dispatch process does not provide credible information to the system operator.
- The system operator does not have sufficient information to operate the market without relying on out-of-market directions to an inefficient degree.
- The system operator has insufficient tools available to it in advance of dispatch to maintain reliability, but more likely security, to an acceptable level.

AEMO and the AEMC will continue to work together on identifying potential deficiencies with, or required improvements to, the current arrangements – particularly in relation to security issues.

It does not appear appropriate that an ahead market that is designed to provide better information to the system operator is required for reliability reasons based on the information available to the Commission. However, it may be the case that such an ahead market may provide some system security benefits. The Commission acknowledges that work is currently underway by AEMO and the AEMC to identify deficiencies with the current NEM arrangements, in relation to both system security and reliability.

In addition, chapter 3 recommends a number of changes to the current arrangements for information provision in the NEM.

Objective 3 - centralised unit commitment:

Appendix B discusses the process currently used in the NEM, whereby each market participant makes their own unit commitment decisions. This section focuses on the third objective of an ahead market (as discussed in the directions paper) which was to move from commitment by market participants to unit commitment by the system operator.

An ahead market designed to achieve objective three would be the largest departure from the current NEM arrangements. A centralised commitment model, by definition, requires the system operator to take a view about the future and commit units on this basis. The risk of centralised unit commitment decisions taken by the system operator would likely be borne by all market participants (for example through "make whole" uplift payments for generators committed by the system operator but not required with the benefit of hindsight) and ultimately by customers.

The Commission agrees with stakeholder comments that moving responsibility for unit commitment decisions from market participants to the system operator is not appropriate in the NEM to assist with reliability, consistent with the Finkel Panel recommendation on this. There are a number of reasons for this.

The first reason relates to the information available to different parties in advance of dispatch. Although the system operator has a whole-of-system view, it does not have sufficiently up-to-date or granular information on conditions at the individual plant level. It would be very difficult and costly for market participants to provide this information to the system operator in real time. Submissions from stakeholders did not identify any fundamental problems with information provision or the iterative process for making unit commitment decisions that currently exists in the NEM.

Second, as explained in chapter 2 the design and architecture of the NEM rests on commitment decision making by market participants. The risks and costs associated with unit commitment decisions are most appropriately placed on market participants. This is because market participants have strong incentives to maximise their individual profits and therefore efficiently manage these costs and risks. Financial incentives are likely to provide the most robust and transparent driver for efficient decision making. Efficient outcomes can best be promoted by aligning the commercial incentives on businesses with the interests of consumers.

Third, the introduction of centralised unit commitment would impose large costs on the market since it is a significant departure from the current market design. The process of decentralised unit commitment is discussed in more detail in Appendix B and the centralised commitment is discussed in more detail above. It is clear from these discussions that there is a large difference, both practically and philosophically, between decentralised unit commitment by market participants and centralised unit commitment by the system operator.

Given these reasons, based on what is known to the Commission at the time of this report, a move to an ahead market with unit commitment by the system operator is not suitable for the NEM at this time to assist with reliability outcomes. Such a change is unlikely to be in the long-term interests of consumers and therefore does not meet the NEO.

However, the Commission acknowledges that work is currently underway to identify deficiencies with the current NEM arrangements, in relation to both system security and reliability. While it is not clear that an ahead market with centralised unit commitment would be beneficial from a reliability perspective it could - at some point in the future - provide some system security benefits.

Given the number of changes that would be required in advance of an ahead market with centralised unit commitment providing any demonstrable system security benefits, the introduction of an ahead market of this kind is unlikely to meet the NEO for many years. Further, as noted above, any potential system security benefits associated with the introduction of an ahead market would need to be carefully assessed against the associated costs, which are likely to be substantial.

FINDING

A move to an ahead market with centralised unit commitment is not suitable for the NEM at this time to assist with reliability outcomes. Such a change is unlikely to be in the long-term interests of consumers and so therefore does not meet the National Electricity Objective.

5.4 Self-forecasting by wind and solar generators

The Commission has considered the issue of self-forecasting by wind and solar generation operators as an initiative that could improve forecast accuracy. Improved accuracy would allow market participants and the system operator to make more efficient operational decisions, promoting reliability outcomes in the NEM.

AEMO and ARENA are conducting a trial whereby operators of utility-scale wind and solar generation will be able to provide a forecast of their expected output for the upcoming dispatch interval – see the box below.

BOX 4: AEMO-ARENA WIND AND SOLAR SELF-FORECASTING TRIAL

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. These systems cover the forecasting timeframe from five minutes to two years. The output from these systems are inputs into the unconstrained intermittent generation forecast (UIGF) with this used (amongst other things) in dispatch, pre-dispatch and short-term PASA.

AEMO and ARENA are collaborating on a project to enable self-forecasting by utility-scale wind and solar projects on a voluntary basis. The Commission understands that from mid-2018, operators of wind and solar generators will be able to provide an output forecast for the upcoming dispatch interval. So long as the self-forecast satisfies a series of validation checks, it will take precedent over AEMO's UIGF. The Commission understands that participants often have the capability to forecast more accurately than AWEFS by factoring in the operational status of individual turbines and ambient conditions that AWEFS does not reflect.

Self-forecasting could have benefits for reliability if wind and solar operators are able to outperform the central forecast in the hours ahead time frame. For example, if a decrease in regional wind output is anticipated more accurately and further in advance, other generators which may require time to organise fuel supplies and synchronise with the grid are more likely to be available to generate while the wind is not blowing.

The directions paper sought feedback on whether the rules should include an obligation on the operators of wind and solar generation to provide self-forecasts of their expected output.

The submissions received on the directions paper indicated that there is broad support for the self-forecasting trials that AEMO and ARENA are conducting. Several stakeholders thought that non-scheduled generation should also be eligible for self-forecasting.[95] There was a general view that changes to the rules should only be considered once the trials have concluded, and that if this does become a feature of the rules it should be on an opt-in basis. Some questioned the lack of regulation around the self-forecasts[96] and suggested that there may be the potential to manipulate pricing outcomes by generators under forecasting to inflate the spot price.[97]

The Commission agrees that the AEMO-ARENA trials will inform possible changes to the NER, so it is appropriate to wait for the results to be known. The Commission understands that the ARENA-funded projects assessing market and financial benefits are expected to run until late 2019. So that conclusions can be drawn on potential benefits for reliability, it is important that the trials consider the ability of wind and solar generation operators to outperform centralised forecasting in the hours ahead of dispatch since it is this time horizon that is important for making decisions that affect reliability outcomes. It would be advantageous for this study to consider the ability to outperform under a range of weather and power system conditions. An important aspect of ARENA funded trials is the knowledge sharing components, it will be important for learnings to be shared in a timely manner in order to appropriately inform rules development in this space.

The Commission also considers that there would be value in allowing non-scheduled wind and solar generators to participate in the self-forecasting trial. Although the benefits of self-forecasting for operators of non-scheduled generation are likely less than for semi-scheduled generation as they are not subject to being constrained down, some may still be able to derive a private benefit through improved contribution factors in the FCAS causer pays regime. Where this occurs, there would also be the opportunity for a wider system benefit from improved forecast accuracy.

On the issue of regulating self-forecasts, the Commission considers that this question will be addressed if there is a rule change request resulting from the trials. In the interim, the potential for spot price manipulation appears to be mitigated by two factors:

1. AEMO intends to apply a series of checks when assessing the suitability of participant self-forecasts for use as UIGFs in dispatch. AEMO is currently consulting on a process that includes an initial assessment before a participant's self-forecast is first used in dispatch, and an ongoing process to assess forecast performance on a weekly basis. At each stage, it is proposed that the self-forecast will have to out-perform the corresponding forecast produced by AWEFS or ASEFS, else the centralised forecast will continue to be used.[98]
2. The risk of a semi-scheduled generator being capped at an output level below its full potential. If a semi-scheduled wind or solar operator deliberately under forecasts its potential output, it risks being capped at this output level if a constraint is applied by the central dispatch engine.

95 ERM Power, Infigen Energy.

96 Bids and offers submitted by scheduled generators, semi-scheduled generators and scheduled loads are prohibited from being false or misleading under clause 3.8.22A of the NER. This is civil penalty provision.

97 AGL Energy, Major Energy Users.

98 AEMO, *(Draft) Semi-Scheduled Generation Self-Forecast - Assessment Procedure*, July 2018.

The Commission considers that the potential for price manipulation should be evaluated during the AEMO-ARENA trials to aid in the identification of an appropriate regulatory mechanism for self-forecasting.

RECOMMENDATION 3: SELF-FORECASTING BY WIND AND SOLAR GENERATORS

- ARENA is encouraged to continue to develop trials for projects that explore the potential for forecast improvements in the hours ahead of dispatch, and to share the learnings of these projects in a timely manner through existing knowledge sharing arrangements, including with the Commission.
- AEMO should consider providing the functionality for non-scheduled generators to participate in the existing trial that is available to semi-scheduled generators. AEMO should also seek to identify an appropriate regulatory arrangement to govern the provision of self-forecasts from all generators involved in the trial.

5.5 Health of the contract market

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. 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 is a vital element of the wholesale market for supporting efficient investment and operation over time.

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

5.5.1 Relationship between contracts and reliability

All electricity traded in the NEM must be settled through the spot market (known as a gross pool) and the variability of demand and supply conditions results in fluctuations in spot prices, which presently can range from a market price cap of $14,500/MWh to the market floor price of -$1,000/MWh.

Both buyers and sellers appreciate that large swings in spot prices have a similar but opposite effect on their costs and revenue and, consequently, their profits and share price. This encourages both buyers and sellers to agree to contracts that convert volatile spot revenues and costs for more certain cashflows or to help underwrite further investment in both generation and retail assets (vertical integration).

Contracts increase certainty for participants and incentivise generators to be available when needed by the market to support their contract positions. For example, if a generator sells a hedge or cap contract for a fixed quantity then, at times when the market signals a need for more supply by the price approaching the market price cap, the generator faces a high penalty for not generating the quantity specified in its contract.

The above discussion demonstrates the role that the contract market plays in the short-term, over operational timescales. The contract market also plays an important role over the longer term, supporting reliability by:

- providing market participants signals of market expectations of future spot prices (a forward price curve), which supports investment and retirement decisions
- lowering the cost of financing of investment in generation capacity, which lowers the cost of achieving efficient levels of reliability
- underwriting retailers' fixed-price offers to end-consumers, such as households and small businesses.

However, the contract market must be relatively liquid to provide confidence to investors and traders of its credibility and to support the reliability benefits described. A liquid market reduces the cost to traders of adjusting their positions to take advantage of new information, which increases willingness to trade and provides investors more confidence in the forward prices signalled by trades.

5.5.2 Contract trading data

There are two common ways in which contracts are traded in the NEM:

- Over-the-counter (OTC) contracts are a direct agreement between two parties and as such allow a high level of flexibility in the terms of the arrangement. However, because they are based on bilateral arrangements, they are not transparent. AFMA used to undertake a survey of OTC contracts, which was discontinued in 2015, which provided some transparency of these contracts. We understand that AFMA is restarting its survey shortly.
- The Sydney Futures Exchange, operated by the ASX, is a common exchange where participants trade in a number of standardised futures products. Trade is anonymous and risk is managed through a mark-to-market process. Since this trade of standardised products, there is transparency of these trades.

In response to the issues paper, stakeholders expressed concerns about the ongoing health of the contract market and AEMO and the Grattan Institute provided charts as evidence so we interrogated trading data ourselves. The two charts the Grattan Institute presented[99] were based on AFMA surveys that were discontinued in 2015 and showed:

- Annual volume of electricity traded as a share of regional consumption from 2003-04 to 2014-15.

99 Grattan Institute, Next generation: the long-term future of the National Electricity Market, https://grattan.edu.au/report/next-generation-the-long-term-future-of-the-national-electricity-market/, September 2017, pgs 20-21.

- Annual percentage of megawatt hours under contracts of 1 year or less from 2010-11 to 2014-15.

AEMO presented an annual ASX Cleared Volumes from 2003-2016.[100]

As noted above, since the AFMA survey was discontinued the only way to analyse up-to-date information on contract trading is to look at ASX data. For the interim report, we attempted to reproduce these charts using ASX base futures trading data to see if we could get similar results and to bring the data up to date. Appendix C contains an updated version of charts 5.4-5.6 from the interim report.

This view of a subset of data (i.e. from the ASX) - given it is a subset of data we would hesitate on drawing strong conclusions from it. However, this data does not support a significant cause for concern from a reliability perspective:

- Despite the decline since those highs in the first quarter of 2011 and 2012, recent levels of trading do not appear to be of significant concern, nor obviously trending downwards.
- In the regions, base futures:
  - continue to be thinly traded in South Australia
  - show signs of recovery after a period of decline in New South Wales
  - are trading at relatively healthy levels in Queensland and especially in Victoria.

The ACCC, in the final report of its Retail Electricity Pricing Inquiry, makes similar findings.[101] However, the ACCC's access to OTC trading data from its own retailer survey suggests this form of trading was at a low ebb in the last year of trading reported by AFMA (2014-15) and has bounced back considerably in the last two years.[102] This means our reporting of ASX trading tends to overplay indications about decreased trading.

It is therefore likely that the updated chart of percentage of long traded (over one year) base futures (Figure C.3 in appendix C), which shows a notable decline in trading, might also be of less concern if OTC trading has increased in the last two years.

The Commission notes the ACCC's access to both OTC and ASX contract trading has provided it with insights that has led it to recommend (recommendation 6) to improve access to trading of OTC data beyond that provided by AFMA.[103] However, it also recommended introducing market making obligations in South Australia to require large, vertically integrated retailers to make offers to buy and sell specific hedge contracts each day, in order to boost hedge market activity (recommendation 7).[104]

Therefore, while we find the data we have access to insufficient to make a recommendation from a reliability perspective, our findings support the case for working to improve the transparency of the contract market (see section 3.3).

100 AEMO, Submission on the issues paper, p. 5.

101 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018, Figure 5.3, p. 114.

102 Ibid. table 5.2, p. 116.

103 Ibid. p. 122.

104 Ibid. p. 130.

5.5.3 Impact of the proposed National Energy Guarantee

The ESB's detailed design consultation paper was published on 15 June 2018. The proposed Guarantee builds on existing spot and financial market arrangements in the electricity market to facilitate investment in dispatchable capacity. The ESB considers that the Guarantee should result in an increase in the proportion of generation capacity contracted and could incentivise investment in low cost dispatchable resources, which may include intermittent renewables 'firming up' their capacity. This could enable renewable generators to supply firm-capacity contracts such as swaps and caps and compete with existing dispatchable capacity, increasing contract supply and liquidity and lowering contract prices.

5.5.4 Further signs of market adaptation

We have seen the contract market adapting to the transformation that is currently occur. Businesses and governments are contemplating or moving to take advantage of opportunities that the transition creates - see below.

Snowy 2.0

On 16 March 2017, Snowy Hydro announced its proposal to carry out a feasibility study into the expansion of the pumped hydro-electric storage in the Snowy Mountains Scheme, also known as the Snowy 2.0 project. Snowy 2.0 is a pumped hydro project that will add an extra 2,000 MW of generating capacity and about 350,000 megawatt hours of energy storage to the existing Snowy hydro scheme. As its webpage says:[105]

> "Snowy 2.0 will act like a giant battery, storing water which can be used as energy at times of high energy demand. As the economy decarbonises we are seeing more intermittent sources of electricity generation (like wind and solar) added to the energy mix while coal fired generation is retiring. This change in the energy market will make large-scale storage projects like Snowy 2.0 critical."

The Tesla battery in South Australia

The Hornsdale power reserve is a South Australian Government project to construct 100 MW/129 MWh lithium battery provided by Tesla at Neoen's 309 MW Hornsdale Wind Farm in South Australia. While ostensibly to provide reliability services:[106]

"A portion of the battery will also be dedicated to trading on the electricity market. This capacity will be used to store power from the Hornsdale Wind Farm when demand is low and dispatch it when demand is high, reducing the need for expensive gas 'peaking plants' and placing downward pressure on power prices for South Australian consumers."

Origin-Tempus flexible energy demand trial

On 11 October 2017, Origin announced it was working with UK-based startup Tempus Energy, which is part of the global Free Electrons accelerator co-founded by Origin and seven other

105 Snowy Hydro, Snowy 2.0 webpage, http://www.snowyhydro.com.au/our-scheme/snowy20/, accessed on 20 November 2017.

106 HPR, Hornsdale power reserve overview webpage, http://hornsdalepowerreserve.com.au/overview/, accessed on 20 November 2017.

utilities from around the world. According to Origin, "during the trial, Origin will use Tempus Energy's demand-side management platform to shift non-time critical load into cheaper periods or when renewables are plentiful, and test the potential savings that could be unlocked for the customer". It says the "technology can also help overcome the intermittency challenges of renewables, by helping energy to be used more efficiently and effectively".[107]

EnergyAustralia seawater pumped hydro energy storage feasibility study

In early 2017, EnergyAustralia and its Consortium partners Arup Group and Melbourne Energy Institute were awarded $453,000 by the Australian Renewable Energy Agency (ARENA) to partially fund a feasibility study for a new pumped hydro energy storage project using sea water. The potential site is located at Cultana on the Spencer Gulf near Port Augusta in South Australia.[108] EnergyAustralia note the "core business model" for a storage asset like Cultana is "to maximise the arbitrage between buying energy when the price is low and selling it when the price is high".[109]

Lincoln Gap

Lincoln Gap Wind Farm is a 212 MW wind farm project with 10 MW grid scale battery storage, under development by Nexif Energy Australia Pty Ltd, located near Port August in South Australia. The project reached financial close in November 2017, with commissioning scheduled for late 2018.[110]

The CEFC committed $150 million in debt finance to stage one of the Lincoln Gap wind farm. The project is the first in Australia to secure debt finance for a grid connected large-scale battery component, on a non-subsidised basis. Nexif Energy Australia note that "with the scalable battery storage at Lincoln Gap we will be able to offer more flexibility to the national grid and improve the reliability of the system".[111]

We have also noted the following examples of new contracts for firming wind and solar generation.

AGL dispatch firming financial product

AGL launched a new product that would provide "an opportunity to bundle a firm and dispatchable energy source such as gas peaking generation with a non-dispatchable source such as wind, allowing wind to be a part of the contract market".[112]

ERM Power solar risk management product

107 Origin, Media centre webpage, https://www.originenergy.com.au/about/investors-media/media-centre/origin-to-trial-demandmanagement-with-large-customers.html, accessed 20 November 2017.

108 EnergyAustralia, Cultana pumped hydro project webpage, https://www.energyaustralia.com.au/about-us/energy-generation/energy-projects/pumped-hydro, accessed on 22 November 2017.

109 EnergyAustralia, Cultana pumped hydro project, Knowledge sharing report, September 2017, p. 20.

110 Lincoln Gap Wind Farm, About the project webpage, http://lincolngapwindfarm.com.au/about-the-project/, accessed on 12 June 2018.

111 Ecogeneration, http://www.ecogeneration.com.au/sa-wind-storage-project-wins-150m-cefc-debt-funding/, accessed on 12 June 2018.

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

ERM Power launched a solar risk management product “to help manage the risks of intermittent generation”.[113] WattClarity published an article[114] that explains the product in more detail.

These are all encouraging signs the market is adapting to take advantage of the opportunities created by the transition of the generation fleet.

Further, the Commission acknowledges that the ESB’s design of the NEG is expected to encourage greater contracting to support higher levels of reliability in the NEM.

113 LinkedIn, ERM Power’s New Solar Risk Management Product, Post by David Guiver (Executive General Manager Trading at ERM Power), https://www.linkedin.com/pulse/erm-powers-new-solar-risk-management-product-david-guiver/, 23 April 2018, accessed 12 June 2018.

114 WattClarity, New hedging options emerge in the NEM and the energy transition accelerates, http://www.wattclarity.com.au/2018/06/new-hedging-options-emerge-in-the-nem-as-the-energy-transition-accelerates/, accessed 14 June 2018.

6 INTERVENTIONS

6.1 Introduction

This chapter discusses the intervention aspects of the National Electricity Market (NEM) reliability framework. In the review's directions paper (April 2018), the Commission outlined that this final report would present views on the interventions mechanisms in the reliability framework. This chapter examines these mechanisms chiefly from the perspective of power system reliability - although the interactions with system security are considered as well.

The chapter discusses:

- The purpose, types and sequencing of intervention mechanisms.
- Key aspects of the Reliability and Emergency Reserve Trader (the RERT), directions and instructions.
- How intervention mechanisms interact in the long-term.
- Intervention pricing in practice.
- Recent issues with intervention pricing.
- Compensation following intervention events.
- Transparency of the compensation process.

The reliability framework, which includes the reliability settings such as the market price cap, is designed to deliver reliability consistent with the level of the reliability standard. However in operating the power system AEMO is expected to try to avoid any unserved energy (i.e. load shedding) in real time,[115] including by using the intervention mechanisms available to it if necessary.

6.2 Overview of interventions

6.2.1 The purpose of interventions

As discussed in chapter 2, reliability in the NEM is largely driven through the market responding to information provided about the need for resources. If the market fails to respond to the information, AEMO's next step is generally to engage in informal negotiations with market participants to alleviate any supply shortfalls.[116] 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.[117] If those options fail, AEMO may have no other choice but to intervene in the market more directly.

Therefore, intervention mechanisms are a key aspect of the current reliability framework. They enable AEMO to deal with actual or potential supply shortages (of varying degrees of severity) by intervening in the market in certain limited circumstances. Intervention

115 See Clause 4.2.7 of the NER – AEMO is required to keep the system operating to a reliable operating state which implies no unserved energy.

116 Under Clause 4.8.5A(d) of the NER.

117 Clause 3.11.5 of the NER.

mechanisms are 'last resort' powers. The fact that they are a last resort power is an attribute of the current framework strongly supported by stakeholders in submissions to this review.[118] AEMO may only deploy intervention tools in the event that wholesale and contract market price signals, AEMO's information disclosure processes and its informal negotiations with market participants fail to elicit the outcomes needed to alleviate the projected or actual, reserve shortfalls.[119] [120]

From an economic perspective, the purpose of intervention mechanisms in the NEM's reliability framework is to bring about, in certain circumstances, a reliability outcome contrary to that which would have occurred through the market process. An independent report recently described the purpose of interventions as follows:[121]

> "[I]n some circumstances, the market may be unable to deliver an acceptable outcome. At times of scarcity, a decision that is economic for a single generator or load may lead to an outcome that is not optimal for the entire power system. The consequences of an insecure or unreliable system are so severe that the system operator is given the power to override the market outcome – to *intervene* in the market."

The reliability framework establishes that to meet the reliability standard and so deliver an acceptable level of reliability AEMO may make a decision to intervene in the wholesale market. However, such decisions require careful consideration as to the flow-on effects for investment signals and investor confidence.

Intervention mechanisms are an acknowledged and important feature of the market design. Given the changes in the generation mix over the past years and the increasing challenges this has created for the system operator, the use of interventions has increased relative to the past. This has increased the spotlight on them - for their suitability and the frequency of their application and use. Intervention mechanisms are being applied in a range of scenarios to address a range of problems, some for which these mechanisms are not suited.

These mechanisms are not without cost. For example, for the 2017/18 summer AEMO estimates that the total cost of having the RERT on call and activated twice (168.5MW activated in total) was $51.26 million. This cost includes availability payments (i.e. payments for out of market generation/demand response being available regardless of whether or not an event occurs as well as other payments, including activation payments).[122] The costs of interventions are ultimately borne by consumers.

118 See for example the following submissions to the interim report: AGL, Energy Networks Australia, Hydro Tasmania, Flow Power.

119 In the case of the RERT, this is generally to alleviate an identification of a breach of the reliability standard, i.e. if AEMO identifies that expected unserved energy is higher than 0.002 per cent.

120 See clause 3.8.14 of the NER, which requires that submitted dispatch bids and offers be dispatched prior to the exercise of the RERT or implementation of further corrective actions. 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.

121 SW Advisory & Endgame Economics, Review of Intervention Pricing - Final Report prepared for AEMO, 4 October 2017. This is available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group in the meeting pack for Meeting 1.

122 AEMO, Summer 2017-18 operations review, May 2018, p. 5 and 32. Available at https://www.aemo.com.au/-/media/Files/Media_Centre/2018/Summer-2017-18-operations-review.pdf

Because of potential consumer cost impacts and the inherent interference with normal market functioning, the regulatory arrangements limit AEMO's powers to use interventions. For example, the RERT may only be used if AEMO identifies a breach or potential breach of the reliability standard, or for power system security reasons. Additionally, there may be times when AEMO has no choice operationally and/or legally but to require involuntary load shedding[123] to maintain the secure power system.[124] As established in the NER power system security must always take precedence over reliability – the power system is only allowed to operate in an insecure state for 30 minutes, so as not to risk an uncontrolled power system outcome following a credible contingency event.

AEMO has submitted a rule change request to the AEMC to amend the NER in regards to enhancing the RERT.[125] The Commission is exploring the potential improvements to the RERT that are within the scope of that rule change request, through the rule change process rather than through this review. We published a consultation paper on 21 June 2018 and are seeking stakeholder input (closing 26 July 2018). The discussion in this chapter therefore does not cover in detail the issues that may be considered through the rule change.

It will be important to consider the other intervention mechanisms (instructions and directions) alongside our consideration of the RERT. The order in which the three interventions mechanisms are used must deliver the lowest cost outcome for consumers. The NER provides some guidance on this issue but considering the interventions framework as a whole - reviewing the intervention mechanisms alongside the enhanced RERT rule change - allows this to happen.

6.2.2 Three mechanisms are available to the system operator

Under the NER, there are three key intervention mechanisms related to reliability.[126] These tools are also used to maintain or re-establish power system security. This is important because if the lack of supply to meet demand is allowed to continue an insecure power system will almost always be the result. In brief the three mechanisms are:

- **The Reliability and Emergency Reserve Trader (RERT)** – This allows AEMO to contract for (or 'lock-in') reserves ahead of a period when reserves are projected to be insufficient to meet the reliability standard.[127] At present AEMO can contract for reserves from 3 hours to nine months ahead of the projected shortfall.[128] AEMO can dispatch these

123 Clauses 3.8.14(c) and 4.8.9 of the NER.

124 Clauses 4.2.6 and 4.3.1 of the NER.

125 See https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader . Additionally, the Commission recently has made a determination to reinstatement the long notice RERT i.e. have a procurement lead time of nine months for the RERT – see https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader

126 In regards to the level of reliability supplied by the generation and interconnection assets. Also, a distinction is being drawn for the purposes of the discussion in this chapter between the general term of intervention mechanism and the legal definition of AEMO intervention event as defined in Chapter 10 of the rules. An 'AEMO intervention event' encompasses the RERT and directions, but not instructions. The term 'AEMO intervention event' is used in the rules with respect to intervention pricing and compensation, which apply jointly to directions and the RERT.

127 And where practicable for the maintenance of power system security. Clause 3.20.2 of the NER. See also section 7 of the RERT guidelines developed and published by the Reliability Panel under clause 3.20.8 of the NER.

128 On 21 June 2018, the Commission made a final rule which promotes reliability in the NEM by increasing the lead time available for AEMO to procure out-of-market reserves through the RERT, to nine months ahead of a projected shortfall. This effectively reinstates what was known as the long-notice RERT. For more information see https://www.aemc.gov.au/rule-changes/reinstatement-long-notice-reliability-and-emergency-reserve-trader

reserves in an operational time to ensure reliability of supply and maintain power system security, where practicable.[129] The RERT involves procuring generation and demand response capacity *additional* to that available through the wholesale market. AEMO may contract only with resources that are 'out-of-market'.[130] Examples include a back-up diesel generator (e.g. kept by a hospital) or emergency demand response.

- **Directions** – If there is a risk to the secure or reliable operation of the power system, AEMO can require:
  - a scheduled generator (including batteries >5MW), a semi-scheduled generator (such as a 150MW wind farm), or non-scheduled market generator (for example a 10MW wind farm supplying the wholesale market) to increase (or decrease) their output
  - a scheduled load to decrease (or increase) consumption
  - unless (in the Registered Participant's reasonable opinion) it would be a hazard to public safety, materially risk damaging equipment or contravene any other law.[131] For instance, a direction could involve AEMO directing a generator to cancel a maintenance activity and return to service as soon as possible.[132]

Directions may also apply to market network service providers (currently only Basslink).[133] For the direction to be effective, the directed plant must have enough time to 'start up' and/or increase its output ('ramp up').

- **Instructions** – If there is a risk to the secure or reliable operation of the power system, AEMO can require a large energy user to temporarily disconnect its load or reduce demand.[134] AEMO may also instruct a network service provider to shed and restore load consistent with schedules provided by the relevant state government.[135] Instructions refer to all remaining registered participants that cannot be subject to a direction (i.e. not scheduled plant or a market generating unit).

In addition to the NEM intervention mechanisms, each NEM jurisdiction has broad emergency powers granting relevant Ministers the ability to issue directions to respond to energy supply emergencies. Such powers extend to issuing directions relating to the use or supply of

129 Clause 3.20.7(a) of the NER.

130 The definition of out-of-market is being considered through the *Enhancement to the RERT* rule change request.

131 Clause 4.8.9(c) of the NER. See also footnote 15.

132 If that generator is a scheduled plant or market generating unit.

133 Clause 4.8.9(a). A direction can be issued in relation to scheduled plant or a market generating unit. A scheduled plant is defined in the rules as 'a scheduled generating unit, a semi-scheduled generating unit, a scheduled network service or a scheduled load classified by or in respect to that Registered Participant in accordance with Chapter 2.' It is current AEMO policy for a battery >5MW to be registered as a scheduled generating unit, and therefore a battery >5MW could be directed as scheduled plant. The only currently registered market network service provider is Basslink. As at 6 June 2018, the only registered market scheduled loads (and therefore the only scheduled loads potentially subject to a direction) were CS Energy Limited for Wivenhoe Power Station (Queensland, 480MW total for two units), Hornsdale Power Reserve Pty Ltd (South Australia, 80 MW) and Snowy Hydro Ltd for Tumut 3 pumps (NSW, 600MW). While it is possible for AEMO to direct a scheduled load, AEMO advises it has not historically directed a scheduled load. Typically scheduled loads would not be consuming when prices are high. A market generating unit is 'a generating unit whose sent out generation is not purchased in its entirety by the Local Retailer or by a Customer located at the same connection point and which has been classified as such in accordance with Chapter 2'. This category includes non-scheduled market generators, which as at 14 June 2018 numbered 58 generators according the AEMO's NEM Registration and exemption list. Current registration information sourced from https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists

134 This only applies to large users who are registered participants.

135 Clause 4.8.9(a) and 4.8.9(a1)(2).

electricity and other energy sources, which can be exercised at the discretion of the relevant state, or at the request of AEMO. AEMO and each of the NEM jurisdictions (excluding the Northern Territory since it is not interconnected) also have a non-binding memorandum of understanding detailing a process for the use of the emergency powers available to Ministers relating to the management of emergencies relating to the power system. This agreement is the "Memorandum of understanding on the use of emergency powers (2015)" (MOU). The MOU also reflects the general understanding that state based emergency powers are to be used after NEM procedures have been exercised where possible, and with co-ordination between jurisdictions and AEMO.[136]

6.2.3 The sequence of use

The NER establish a sequence for the use of the intervention mechanisms. In times of 'supply scarcity' after dispatching all valid bids and offers, AEMO must use its reasonable endeavours to first exercise the RERT (if it has been procured), and then if necessary, issue either directions or instructions.[137] The term 'supply scarcity' is not defined in the rules and is used only in this specific context.[138] As such, the term is to be read with its plain meaning – namely, periods during which there is a shortage or shortfall of supply.[139] This may include a period during which the reliability standard may not be met. Figure 6.1 summarises the intervention mechanisms in the reliability framework.

The NER are not clear on the priority between directions and instructions. The criterion for triggering the use of directions and instructions is the same for each mechanism; 'to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state'.[140] In practice, in relation to reliability, AEMO typically has used directions to bring additional capacity online rather than issue an instruction to shed load, consistent with the definition of a 'reliable operating state'.[141]

AEMO's obligation to follow this sequence of steps is a 'reasonable endeavours' obligation. That is, AEMO will be taken to have satisfied its obligation under the clause if it can demonstrate it has taken all action that is reasonable for it to take in the relevant circumstance to follow the sequence under clause 3.8.14. This is in recognition that AEMO will not always be able to achieve a reliable operating state.

136 "National electricity market – memorandum of understanding on the use of emergency powers", November 2015 as accessed from https://www.aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/2016/National-Electricity-Market—Memorandum-of-Understanding-on-the-Use-of-Emergency-Powers—April-2016.pdf on 13 June 2018, with Attachment 1 Emergency Legislation detailing a non-exhaustive list of emergency legislation relating to electricity and energy related emergencies.

137 In general terms, the sequence to be followed under the clause is as follows: all valid dispatch bids and offers submitted by scheduled generators, semi-scheduled generators and market participants should be dispatched (including those priced at market price cap); then, after all such bids and offers are exhausted, AEMO may exercise the RERT (i.e. dispatch/activate scheduled and unscheduled reserves in accordance with r. 3.20); and finally, if necessary, implement any corrective action under clause 4.8.5B and 4.8.9 (i.e. issue directions and clause 4.8.9 instructions).

138 That is, in regards to clause 3.8.14.

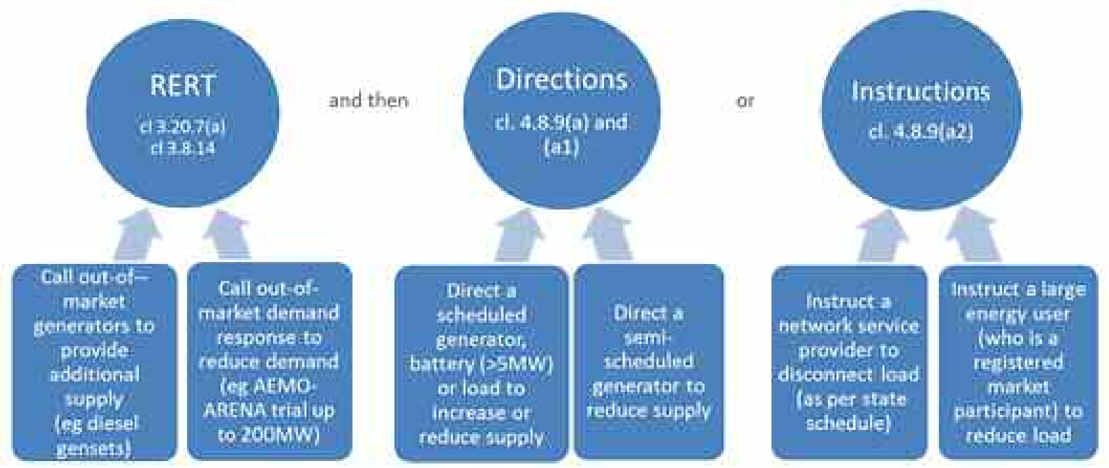
139 The term "supply" is defined under Chapter 10 of the NER as "the delivery of electricity".

140 Under Clause 4.8.9(a)(1) of the NER.

141 The definition of a reliability operating state is discussed in section 4. AEMO publicly states that it views load shedding as an 'absolute last resort' – see AEMO, Summer 2017-2018 operations review, May 2018, p17 and AEMO website; AEMO Market notifications explained – what does a 'lack of reserve' mean? https://www.aemo.com.au/Media-Centre/AEMO-market-notifications-explained, accessed 14 June 2018.

The obligation to dispatch all valid bids and offers, and to dispatch or activate reserves, is subject to "any adjustments which may be necessary to implement action under paragraph (c)"[142] and "any plant operating restrictions associated with a relevant AEMO intervention event".[143] Under clause 3.20.7 of the NER, AEMO may submit, update or vary dispatch bids or offers, or change other inputs to the dispatch process, to give effect to the dispatch or activation of reserve under a scheduled or unscheduled reserve contract. Under clause 4.8.9(h) of the NER, AEMO is similarly able to submit, update or vary dispatch bids, offers or rebids, or change other inputs to the dispatch process, to give effect to a direction or instruction.

Figure 6.1: Overview of intervention mechanisms and examples



Note: Note that, in regards to the sequencing of interventions shown in this diagram, the RERT can only be used if it has been procured. If it has not been triggered and then procured it cannot be used and so AEMO can only use directions and instructions.

6.3 The RERT

The RERT allows AEMO to contract for reserves (generation or demand-side capacity that is not otherwise available to the market through any other arrangement). AEMO can use the RERT in the event that it determines that market participants are not expected to meet the reliability standard (i.e. when AEMO projects that unserved energy in a region is expected to be greater than 0.002 per cent of total energy demanded in that region) and, where practicable, to maintain power system security. The existing RERT can therefore be considered a "strategic reserve". Table 6.1 presents the triggers for procurement and activation/use of the RERT.

142 Paragraph (c) refers to the implementation of "further corrective action" under clauses 4.8.5B and 4.8.9, being the implementation of directions or instructions.

143 See clauses 3.8.14(a)(1) and (2) and 3.8.14(b)(1) and (2) of the NER.

Table 6.1: RERT triggers

PROCUREMENT	DISPATCH
Under the NER, AEMO may determine to enter into reserve contracts to ensure that the reliability of supply in a region meets the reliability standard for that region, and where practicable, to maintain power system security.[144] AEMO's ability to procure the RERT is limited by a number of factors, including that AEMO must consult with relevant jurisdictions with respect to its determination of whether to procure and how much to procure.[145] The NER do not prescribe the amount that AEMO should procure once it has identified a potential shortfall. In relation to reliability, the NER imply that AEMO can only procure so much as would be reasonably necessary to ensure the reliability standard is met (and where practicable, to maintain power system security).[146] However, the way that AEMO operationalises the standard may influence how much reserves it procures.	In relation to activating/dispatching the RERT, in the first instance, AEMO must determine the latest time for exercising the RERT and publish a notice of any foreseeable circumstances that may require implementation of the RERT.[147] Once such time has arrived, the NER state that AEMO may dispatch reserves to ensure that the reliability of supply meets the reliability standard, and where practicable, to maintain power system security.[148]

The RERT guidelines, which are made and reviewed by the Reliability Panel, specify three types of RERT based on how much time AEMO has to procure the RERT prior to the projected reserve shortfalls occurring:

- long-notice RERT - between ten weeks' and nine months' notice of a projected reserve shortfall
- medium-notice RERT - between ten weeks' and one week's notice of a projected reserve shortfall
- short-notice RERT - between seven days' and three hours' notice of a projected reserve shortfall.

Typically, AEMO sets up a RERT panel of providers for both the medium-notice and short-notice RERT and only triggers the procurement contract when it has identified a potential

144 Clause 3.20.3(b) of the NER.

145 Clause 3.20.3(c) of the NER.

146 Clauses 3.20.2(a) and 3.20.2(b) of the NER.

147 Clause 4.8.5A and clause 4.8.5B of the NER

148 Clause 3.20.7(f) of the NER

shortfall and after seeking offers from RERT panel members.[149] There is no panel for the long-notice RERT; rather, contracts are signed following the close of a public tender process.[150]

During periods of supply scarcity, AEMO must use its reasonable endeavours to act in accordance with the sequence set out in section 6.2.3.

From a regulatory perspective, the RERT is a voluntary mechanism involving a tender process and/or pre-agreed RERT panel process. It is a tool that is arranged in advance (i.e. contracts procured and/or RERT panel established in advance) and dispatched in real or operational timeframes.

6.3.1 Principles for the RERT

AEMO's ability to determine whether to procure reserves, and its determination of the amount of those reserves, is limited by a number of requirements.[151] A number of these are also relevant to AEMO's ability to dispatch the RERT. Broadly speaking, they require AEMO to seek to minimise market distortion and maximise the effectiveness of the RERT at least cost to consumers.[152]

In particular, AEMO:

- *Is to ensure as far as reasonably practical* the number of affected participants and the effect on interconnector flows is minimised.[153]
- When procuring or dispatching the RERT must *have regard to* the following principles:[154]
  - 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.
- Must have regard to the RERT guidelines which are made and published by the Reliability Panel (last revised in 2018 to reflect the final rule made by the Commission to reinstate the long-notice RERT).[155] These provide additional guidance with respect to AEMO taking actions that have the least distortionary effect on the market, both in relation to the

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

150 For more detail on the RERT framework, such as on the operationalisation of the reliability standard, RERT procurement lead time and contracting periods, and on history of the RERT and the RERT in practice, refer to Chapter 2 of the Commission's consultation paper National Electricity Amendment (*Enhancement to the Reliability and Emergency Reserve Trader*) Rule 2018 https://www.aemc.gov.au/sites/default/files/2018-06/Consultation%20paper_0.pdf

151 The NER provide the high-level framework within which AEMO may procure and dispatch the RERT. Rule 3.20 of the NER.

152 Clause 3.20.2(b) of the NER.

153 Clause 3.8.1(b)(11) of the NER.

154 These are termed 'the RERT Principles'. Clause 3.20.2(a)(3) and 3.20.2(b) of the NER.

155 Clause 3.20.8 of the NER.The Guidelines must include: the information AEMO must take into account when deciding whether to exercise the RERT; the actions that AEMO may take to be satisfied that reserves contracted under the RERT are out of market; any additional assumptions about key parameters that AEMO must take into account in assessing cost effectiveness; and additional forecasts that AEMO should take into account prior to exercising the RERT. Clause 3.20.8(a)(1), (3), (56) and (7) of the NER. Reliability Panel, *Reliability Standard and Settings Guidelines*, 1 December 2016. Hereafter, these are referred to as the "RERT guidelines". As already outlined, AEMO must exercise the RERT in accordance with a number of other provisions in the NER that relate to central dispatch and market operation, including in relation to Clause. 3.8.14 of the NER and sequencing. See also clause 3.20.2(c) of the NER.

short-term impact on the spot prices and the long term impact on investment signals. They also guide AEMO as to the cost effectiveness of the RERT, and factors relevant to the consideration of the cost effectiveness of exercising the RERT, in consultation with relevant participating jurisdictions.

- Can only exercise the RERT *in accordance with* the RERT procedures, which are made and published by AEMO.[156]

6.3.2 Pricing under the RERT

When the RERT is activated (or when AEMO issues a direction under clause 4.8.9 - discussed further below in section 6.4), AEMO is required to set prices to the value which AEMO, in its reasonable opinion, considers would have applied had the RERT activation or direction not occurred.[157] This practice, known as 'intervention pricing', is applied whenever the RERT is activated (whereas directions relating only to localised issues do not trigger the requirement for intervention pricing). Intervention pricing is meant to preserve market price signals to minimise the distortionary effect of the RERT activation or direction. Intervention pricing is discussed further in section 6.7.

6.3.3 Reporting and evaluation for the RERT

There are no specific compliance provisions with respect to the RERT. However, if the RERT is dispatched, AEMO must as soon as practicable thereafter publish a report that details matters including:[158]

- the circumstances giving rise to the need to dispatch reserves
- the basis on which it determined the latest time for that dispatch and on what basis it determined that a market response would not have avoided the need for dispatch
- the changes in dispatch outcomes as a result of the dispatch of reserves
- the process implemented by AEMO to dispatch reserves.[159]

Each year the Reliability Panel's annual market performance review must provide observations and commentary on the security, reliability and safety of the national electricity market.[160] The Panel's analysis of market performance in terms of reliability considers amongst other elements the use of intervention mechanisms in the preceding year.

6.4 Directions

Reliability directions, the RERT and instructions were initially conceived as transitional mechanisms with sunset clauses. However, in 2008, the Commission extended these provisions indefinitely. In making its decision, the Commission concluded that reliability directions were necessary as a last resort mechanism to maintain reliability of supply,

156 Clause 3.20.7(e) of the NER
157 Clause 3.9.3 of the NER
158 Clause 3.20.6(a) of the NER
159 The remainder of clause 3.20.6 of the NER requires AEMO to provide more information to the market, including reporting on the cost and recovery of the cost of the RERT.
160 Under Clause 8.8.3(b) of the NER.

particularly in light of a projected tightening in the supply-demand balance, and to provide the market with long-term confidence that AEMO is able to intervene to avoid load shedding.[161]

AEMO may issue a direction (or an instruction – discussed further below) to registered participants where it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state.[162] The power system is assessed to be in a reliable operating state when:

- AEMO has not disconnected, and does not expect to disconnect, any points of load connection under clause 4.8.9;
- no load shedding is occurring or expected to occur anywhere on the power system under clause 4.8.9; and
- in AEMO's reasonable opinion the power system meets, and is projected to meet, the reliability standard, having regard to the reliability standard implementation guidelines.'[163]

In contrast to the RERT, directions are a non-voluntary regulatory tool: a registered participant must use its reasonable endeavours to comply with a direction regardless of the financial implications including potential losses - unless to do so would, in their reasonable opinion, be a hazard to public safety, materially risk damaging equipment, or contravene any other law.[164] This clause is classified as a civil penalty provision. Given this, a compensation framework exists to enable directed participants to recover any such losses. This is discussed further below in section 6.8.

According to AEMO's operating procedures, when AEMO considers that it might have to intervene in the market by issuing a direction, it will:

- publish a market notice of the possibility that AEMO might have to issue a direction 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
- issue a direction verbally to the relevant registered participant, confirming whether it is a direction
- issue a participant notice confirming the direction
- issue a market notice advising that AEMO has issued a direction.[165]

AEMO can also impose a counteraction to minimise the effects of a direction. Under NER clause 4.8.9(h)(3), AEMO may apply a counteraction constraint on a selected market participant to minimise the number of affected participants and the effect on interconnector

161 AEMC, *NEM Reliability Settings:* Information, Safety Net and Directions, Final Determination, 26 June2008.

162 Clause 4.8.9(a)(1) of the NER.

163 Clause 4.2.7 of the NER.

164 Clause 4.8.9(c) of the NER.

165 These same steps are applied to clause 4.8.9 instructions. AEMO, *Intervention, direction and clause 4.8.9 instructions*. System operating procedure, September 2014, See 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. Since the system black event in South Australia AEMO has clarified the way it communicates directions by developing a standard script to be used when it issues a clause 4.8.9 direction.

flows during an AEMO intervention event. See the section on this later in this chapter ("*Intervention pricing in practice")*.

6.4.1 Principles for directions

The principles AEMO must follow regarding directions are set out in the NER[166] and may be augmented by guidelines issued by the Reliability Panel (though none have been published to date). As per the RERT, they broadly seek to limit the impact of directions and minimise cost. Some of the principles are put into effect through AEMO's system operating procedures manual.

Specifically AEMO:

- *Is to ensure as far as reasonably practical* when issuing directions that the number of affected participants and the effect on interconnector flows is minimised.[167]
- *Must use its reasonable endeavours* to minimise any cost related to directions and compensation to Affected Participants and Market Customers pursuant to clause 3.12.2 and compensation to Directed Participants pursuant to clauses 3.15.7 and 3.15.7A.[168]
- *Must* observe its obligations under clause 4.3.2 concerning sensitive loads.[169]
- *Must* expressly notify a Directed Participant that AEMO's requirement or that of another person authorised by AEMO pursuant to clause 4.8.9(a) is a direction.[170]
- *Must* take into account any applicable guidelines issued by the Reliability Panel.[171]
- *Should* revoke a direction as soon as AEMO determines it is no longer required.[172]

6.4.2 Pricing under directions

AEMO is also required to set prices during AEMO intervention events to the value which AEMO, in its reasonable opinion, considers would have applied had the intervention event not occurred.[173] This practice, known as "intervention pricing", is applied both when the RERT is activated and when directions are issued. However, some directions do not trigger the application of intervention pricing. Under what is known as the "regional reference node test", intervention pricing is not to be applied when a direction relates only to an isolated part of the network.[174]

Intervention pricing is discussed further below in section 6.7.

166 Clause 4.8.9(b)(1) to (5) of the NER.

167 Clauses 3.8.1(b)(11) and 4.8.9(h)(3) of the NER.

168 Clause 4.8.9(b)(1) of the NER. This principle is to be reflected in AEMO's directions procedures.

169 Clause 4.8.9(b)(4) of the NER. This principle is to be reflected in AEMO's directions procedures.

170 Clause 4.8.9(b)(5) of the NER. This principle is to be reflected in AEMO's directions procedures.

171 Clause 4.8.9(b)(3) of the NER. This principle is to be reflected in AEMO's directions procedures.

172 Clause 4.8.9(b)(2) of the NER. This principle is to be reflected in AEMO's directions procedures. There are no such Reliability Panel guidelines on directions.

173 Clause 3.9.3(b) of the NER.

174 NER, clause 3.9.3(d) provides that normal pricing processes should continue if a direction given to a plant located at the regional reference node would not have avoided the need for the direction issued by AEMO.

6.4.3 Reporting and evaluation of directions

When AEMO intervenes in the NEM through the use of directions, it must publish a report outlining amongst other matters the circumstance giving rise to the direction and the basis on which it determined that a market response would not have avoided the need for the direction.[175] The report does not appear to need to address how AEMO applied the principles governing directions.

As with the RERT, the Reliability Panel's Annual Market Performance Review (AMPR) is a mechanism for annual review by the Panel of the performance of the NEM regarding security, reliability and safety.[176] Past reports examine the occurrence, nature and significance of the issuance of directions.

6.5 Instructions

An instruction differs from a direction in the types of market participants AEMO can require to take action and the nature of the action taken. Instructions generally involve AEMO requiring a network service provider or a large energy user to shed load.

AEMO is taken to have issued an instruction when it requires a registered participant, other than in relation to *a scheduled plant or market generating unit*, 'to do any act or thing if AEMO is satisfied that it is necessary to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state' under Clause 4.8.9 (a1)(2).[177] The categories of registered participants that can be subject to an instruction on the basis that they are neither scheduled plant nor a market generating unit include:

- A scheduled network service provider: A person who owns, operates, or controls a transmission or distribution system and has classified any of its network services as a "scheduled network service".
- The following customers:
- Market load (other than scheduled load): A person who wishes (or is required) to have their load settled on the spot market must register as a market customer. A market customer must purchase all electricity related to the market load from the spot market. Local retailers must be registered as market customers and must classify any connection point that connects their local area to another part of the power system as a market load.[178]
- A first tier load if they are registered: first-tier loads are settled through a local retailer and must not participate in the spot market.

175 Clause 4.8.9(f) and 3.13.6A(a) of the NER.

176 Clause 8.8.3(b) of the NER requires the Reliability Panel to conduct a review of the performance of certain aspects of the market, at least once every calendar year and at other such times as the AEMC may request. The latest report is at https://www.aemc.gov.au/sites/default/files/2018-03/Final%20report.pdf

177 Clause 4.8.8 (a) and 4.8.9 (a1) of the NER.

178 AEMO, Participant categories in the NEM, available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Participant-Categories-in-the-NEM.pdf

- A second tier load if they are registered: second-tier loads are settled through a market customer who is not the local retailer. Second-tier customers must not participate in the spot market.

Currently there are 76 registered market customers, the majority of which are retailers.[179]

The reliability trigger for the AEMO's use of instructions is the same as for directions. AEMO may issue an instruction to registered participants where it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state.[180] As an instruction may involve load shedding it is fundamentally a mechanism for maintaining or returning the system to a secure operating state.[181]

Instructions oblige instructed parties to use reasonable endeavours to comply. As with directions the intervention mechanism is a non-voluntary form of regulation (with some carve outs such as to prevent public safety hazards and material equipment damage).[182] Also akin to directions, instructions are unplanned interventions that occur in operational time.

The significant role of jurisdictions is unique to instructions. Jurisdictions specify in advance the impact of instructions by providing a load schedule. In the event of an instruction, network businesses are required to shed and restore loads in accordance with the schedules provided by the relevant state government.[183]

6.5.1 Principles for instructions

In issuing instructions, AEMO must comply with the sequence of steps outlined earlier. Additionally there are requirements in the rules on AEMO to use reasonable endeavours to shed load across regions in an equitable manner as specified in the power system security standards,[184] and to maintain supply to sensitive loads.[185]

When issuing clause 4.8.9 instructions:

- AEMO must use its reasonable endeavours to ensure that the national electricity system is operated in a manner that maintains the supply to sensitive loads.[186]

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179 As at 7 June 2018, based on AEMO's NEM Registration and Exemption List, accessed on 7 June 2018 at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists This appears to include all registered market customer types (noting that registered Participants can be registered in more than one category).

180 Subsequent to complying with the sequence of steps outlined earlier (for instance first activating the RERT).

181 See reporting section. Notably, while the rules require that the AEMO report on instructions assess the appropriateness of actions taken to restore or maintain power system security they do not require the report to assess the actions with regards to the restoration or maintenance of a reliable operating state.

182 Under Clause 4.8.9(c) : A Registered Participant must use its reasonable endeavours to comply with a direction or clause 4.8.9 instruction unless to do so would, in the Registered Participant's reasonable opinion, be a hazard to public safety, or materially risk damaging equipment, or contravene any other law. This clause is classified as a civil penalty provision. See also Clause 4.8.9(c1).

183 See Clause 4.3.2(f) of the NER and National Electricity Law Part 8 (section 111). A Memorandum of Understanding (MOU) and the National Electricity Market Emergency Protocol were developed by the Jurisdictions, that is, South Australia, Victoria, New South Wales, Queensland, Tasmania, and AEMO, to co-ordinate actions to be taken under individual state legislation to manage power system security emergencies. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/2016/National-Electricity-Market-Emergency-Protocol—-April-2016—-Signed.pdf

184 Clause 4.8.9(i) of the NER.

185 Clause 4.3.2(f) of the NER.

186 Part 8, section 114 of the National Electricity Law.

- To implement load shedding across interconnected regions, AEMO must use reasonable endeavours to implement load shedding in an equitable manner as specified in the power system security standards, taking into account the power transfer capability of the relevant networks.[187]
- AEMO must comply with its obligations under clauses 4.3.2(e) to (l) of the NER which include a requirement for AEMO to maintain a set of load shedding procedures for participating jurisdictions and Part 8 of the National Electricity Law regarding the safety and security of the national electricity system.[188]

6.5.2 Pricing under instructions

In contrast to the RERT and directions, intervention pricing is not triggered in relation to instructions to shed load issued under clause 4.8.9. Instead, AEMO sets the regional price to the market price cap when involuntary load shedding occurs.[189] This can be considered a form of intervention pricing in its broader sense, but is not intervention pricing as defined in the NER.

Intervention pricing is discussed further below in section 6.7.

6.5.3 Reporting and evaluation of instructions

The requirement on AEMO to report on instructions is provided for separately in the NER to the directions reporting obligation.[190] If AEMO issues an instruction for load shedding, it must conduct a review of the incident to assess the adequacy of the provision and response of facilities or services, and the appropriateness of actions taken to *restore or maintain power system security.*[191] AEMO must also prepare a review report and make it available to Registered Participants and to the public.[192] Registered participants must co-operate in any review conducted by AEMO, including making records and information available.[193]

As with the RERT and directions, the Reliability Panel through the annual AMPR may analyse and report on the occurrence, nature and significance of instructions in regards to the reliability of the NEM.

6.6 How the intervention mechanisms interact in the long-term

6.6.1 Trends in directions and instructions

The RERT

Prior to 2017, the RERT had only been procured three times and had never been dispatched.

In 2017, AEMO procured reserves through the long-notice RERT and introduced new panel members to the short-notice RERT panel through the ARENA-AEMO demand response trial.

187 Clause 4.8.9 (i) of the NER.

188 Clause 4.8.9 (j) of the NER.

189 Clause 3.9.2(e)(1) of the NER.

190 Reporting on instructions is addressed in Clause 4.8.15 while reporting on directions is clause 3.13.6A.

191 *Clause 4.8.15(b) of the NER, emphasis added.*

192 Clause 4.8.15(c) of the NER.

193 Clause 4.8.15(e) of the NER.

The RERT was activated twice in 2017-18 to maintain the power system in a reliable operating state.[194] On 30 November 2017, the RERT was activated (i.e. dispatched)[195] for the first time. AEMO also entered into reserve contracts in January 2018 and dispatched the RERT in Victoria and South Australia. AEMO has noted that both short- and long-notice RERT providers were used.[196]

In June 2018, following a number of LOR2 notices in New South Wales, AEMO entered into reserve contracts (i.e. it procured the RERT) on 7 June and again on 8 June. The RERT was not dispatched on either of those events. Costs in relation to those events are not yet known.

Directions

The use of the directions has increased markedly over the last year; direction events have increased in number and duration.

Figure 6.2 presents the number of direction events since 2006-07. It shows that:

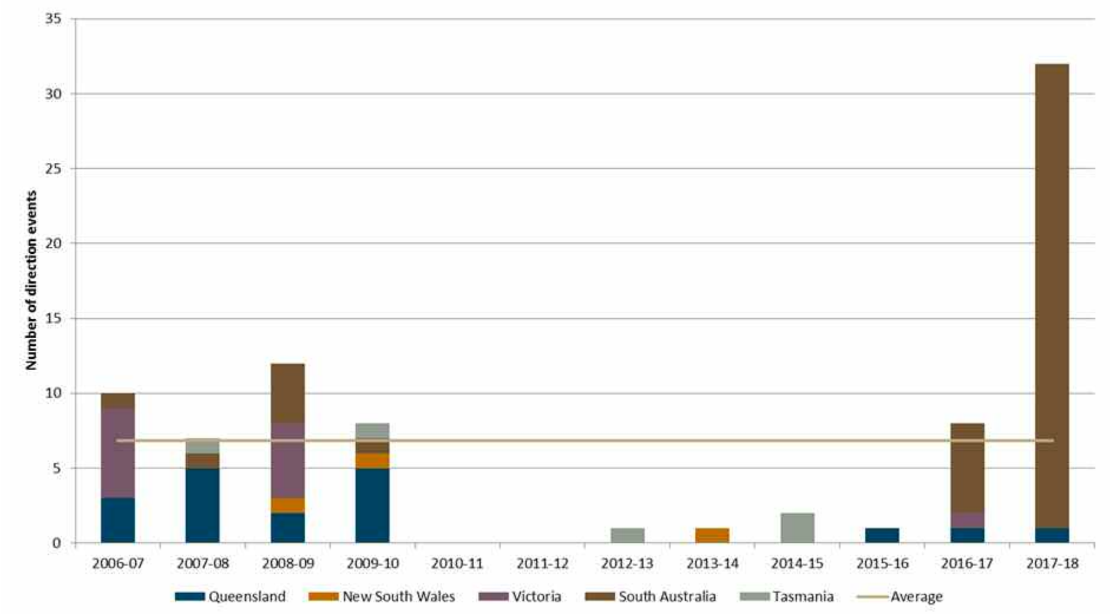
- The number of direction events in this financial year (2017-18) was the highest of the past ten years. The number of events was four times higher than the past financial year (32 in 2017-18 compared to eight in 2016-17).
- All but one of the direction events this financial year (2017-18) occurred in South Australia.
- Over the past two years almost all of the direction events involved maintaining the system in a secure operating state (38 of 40 events). Only two direction events were to maintain the system in a reliable operating state.

194 These were in Victoria, on 30 November 2017 and 19 January 2018. AEMC Reliability Panel, 2017 Annual Market Performance Review, final report, 20 March 2018. Sydney, p. xix, footnote 59.

195 The term activation is used to refer to the dispatch of unscheduled reserves.

196 For details see AEMC 2018, *Enhancement to the Reliability and Emergency Reserve Trader*, Consultation Paper, 21 June 2018, Sydney pp16 -17.

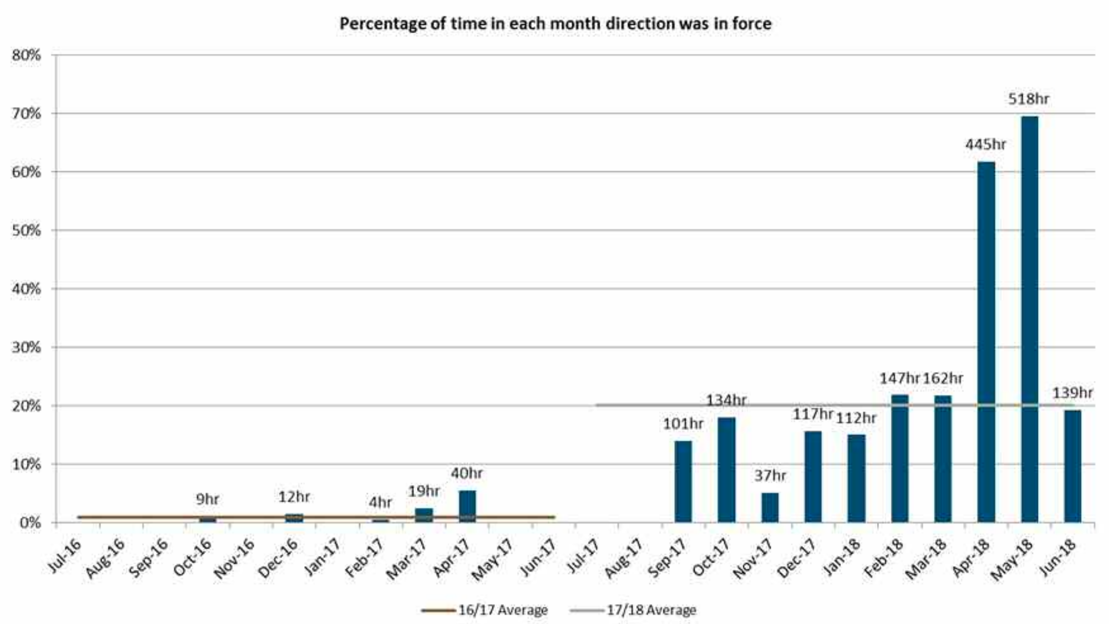
Figure 6.2: Direction events in the NEM



Note: Data provided by AEMO. 2017-18 includes data up to 30 June 2018, i.e. the full financial year. The chart includes directions issued under clause 4.8.9 of the NER. Note directions data provided by AEMO to the Reliability Panel incorporated two additional events in 2016-17, not included in this chart, which were issued under the NEL section 116. These were instructions to shed load in South Australia on 8 February 2017 and in New South Wales on 10 February 2017, and were included in the Reliability Panel's AMPR report.

The proportion of time in which a direction event has been in force in the NEM has risen noticeably over the last year. Figure 6.3 presents the percentage of time per month that directions were in force since July 2016. For 2017-18 a direction event was in force in the NEM on average approximately 20 per cent of time, up from 1 per cent in 2016-17. Notably, directions were in force for over 60 per cent of the time during April and May 2018. That is, in 2017-18 a direction event was in force on average 159 hours per month; in 2016-17 the average figure was seven hours per month.

Figure 6.3: Direction duration



Source: AEMO data and direction event reports. AEMC analysis.

Note: The percentage calculations are based on the total number of hours per month, which varies month to month. The assumptions made regarding how directions are grouped may affect total monthly hours.

Since April 2016, AEMO has issued only two instructions resulting in load shedding. Both of them were in February 2017.[197]

6.6.2 Preliminary views

The Commission considers that it remains appropriate for the NEM to have some form of reserve mechanism to act as a safety net and as one of the last resort alternatives to involuntary load shedding.

However, the increased use of intervention mechanisms, including for reliability purposes, has brought interventions into the spotlight. Interventions are being applied in a range of scenarios to address a range of problems, some for which the mechanisms are not suited. To understand the reasons for the market intervention and identify any 'lessons learnt' for the NEM, the use of interventions needs to be examined on a case–by-case basis: it is important to understand the circumstances involved with each intervention before considering whether the increased use of intervention mechanisms are indicative of broader problems.

Most of the directions that have occurred to date, and that account for the increased number of interventions, are the system strength directions being used in South Australia. This issue

197 AEMC analysis of AEMO's *Power system operating incident reports*. These were in South Australia on 8 February 2017 and in New South Wales on 10 February 2017. For details, see AEMC Reliability Panel, 2017 Annual Market Performance Review, final report, 20 March 2018, Sydney, discussion starting p.58 and p. 110. https://www.aemc.gov.au/sites/default/files/2018-03/Final%20report.pdf

is discussed further in chapter 5. It is important to note that typically these interventions are occurring for *security* reasons to maintain system strength levels in South Australia, not *reliability* reasons.

The increased spotlight on interventions - their suitability and the frequency of application and use has led the Commission to consider that it is timely to examine intervention mechanisms, and the rules underpinning them, from a broad 'framework' perspective. It is also important to consider these in conjunction with the rule change proposal to modify key aspects of the RERT rules, submitted by AEMO, which is considering the RERT framework holistically. [198] Considering the interventions framework as a whole - reviewing the intervention mechanisms alongside the enhanced RERT rule change - allows this to happen.

The Commission's initial comparative assessment and the views of this review's technical working group suggest there are a range of aspects of the overall framework for interventions that could benefit from further consideration. These matters should therefore be examined through an AEMC review of the interventions mechanisms. It will be important to consider the rules related to directions and instructions, but we also consider there is also a need to look at interventions and the rules from the perspective of how interventions occur and operate as a suite of mechanisms. This is supported by stakeholders.

In considering what matters should be examined, the Commission considers the following areas would warrant attention:

- Whether the rules provide an adequate level of clarity regarding the hierarchy between the intervention mechanisms. Interventions remain relatively infrequent, are time-critical (activated in real operational time) and involve complex data management, analysis and communications. Clarity about the hierarchy of use of the three intervention tools is essential for maximum efficacy. Is the preferred hierarchy of activation between the RERT, directions and instructions sufficiently clear in the rules (and associated procedures), in the case of both a system security event and 'supply scarcity'? Alternatively, are the circumstances under or principles by which one mechanism should take priority over the others as well-defined as possible? For example could a reasonable endeavours 'least cost' principle across the mechanisms be valuable? Currently the NER could be interpreted as requiring the RERT to be used prior to directions in the event of supply scarcity. This could result in higher cost resources (i.e. RERT resources, which by definition should have a value higher than the market price cap) being used ahead of directing on cheaper generators.
- Analysing the principles that constrain and guide AEMO's use of each mechanism. The intention is that each mechanism is designed to be operationalised in a way that results in the smallest disruption possible to the ongoing operation of the market. Nonetheless there appear to be some disparities between the principles applying to each mechanism.

198 For instance, the rule change process with examine the concerns AEMO has raised about the apparent inconsistency in the rules between the reliability outlook that could allow the system operator to intervene using the RERT compared with that which allows AEMO to issue a direction. AEMO may only use the RERT to ensure the reliability meets the reliability standard, while it may issue a direction to avoid any unserved energy (load shedding). Given the reliability standard is a maximum expected unserved energy in a region of 0.002 per cent of the total energy demanded in that region for a given financial year, it is unclear whether a difference is intended in the rules, if one is appropriate, and/or whether such a difference can apply in practice or operationally.

For instance the principles regarding minimising cost for the RERT cites both maximising effectiveness and minimising cost to end use consumers of electricity. The obligation on AEMO in regards to directions does not directly mention end use customers in regards to minimising costs (and compensation).[199] AEMO is to 'have regard to' the RERT cost principle and apply the higher bar of 'reasonable endeavours' to meet the directions cost principle.[200] Differences between the principles governing how AEMO is to apply each mechanism may be appropriate even within the broad goal of limiting the impact of interventions on the market.

- Consider the mechanisms in regards to both reliability and system security to better understand the circumstances under which each tool could prove most effective and test the framework. For example, it may be that directions have greater utility in addressing system security than reliability, for instance. Reliability directions typically occur at very tight demand-supply balance periods where, presumably, the prevailing price is close to the market price cap. It could therefore be argued that most generating units, if online and functioning properly, would already be generating for dispatch into the wholesale market. On the other hand, it may not always be commercially advantageous and/or reflect a firm's risk appetite for a generator to make itself available each time a forecast indicates a tight supply-demand balance.
- Consider the need for a clear, timely evaluation process for a series of interventions. The event-based intervention reports by AEMO could be augmented to identify whether events of a similar nature have occurred previously, and to analyse whether they could occur again. In other words, with the increasing incidence of interventions there should be a timely process for identifying, analysing and learning from a serial problem.

RECOMMENDATION 4:

The AEMC will review the NEM intervention mechanisms of directions and instructions, including the rules governing them, from the perspective of how interventions occur and operate as a suite of mechanisms (including in relation to the RERT), in regards to both reliability and system security through our reliability work program.

6.7 The role of intervention pricing

As noted earlier, when a relevant AEMO intervention event occurs, AEMO must set the dispatch price and ancillary services price at the value which AEMO, in its reasonable opinion, considers would have applied had the AEMO intervention event not occurred.[201] For this reason, intervention pricing is often referred to as "what if pricing" – what would the price have been if the intervention had not occurred?

199 There is an obligation to minimise costs to affected participants and market customers under Clause 4.8.9(b)(1), and market customers pass on costs to end users. However there may be benefit in examining why the principles terminology in directions should be different to that for instructions.

200 Clauses 4.8.9(b)(1) and 3.20.2(b) of the NER.

201 Clause 3.9.3(b) of the NER. A relevant AEMO intervention event includes the activation of the RERT and the issue of directions. As noted earlier, intervention pricing is not implemented when directions apply only to isolated network areas.

AEMO determines the intervention price in accordance with an intervention pricing methodology developed in accordance with clause 3.9.3(e).[202] As the methodology notes, the aim of intervention pricing is to preserve the market signals that would have existed had the intervention not occurred. Such signals are important as they are designed to convey to stakeholders the need for investment in additional capacity (in cases where price signals reflect scarcity in the market) and to provide signals and incentives to participants in operational timescales. In this way, intervention pricing seeks to minimise the market distortion that would otherwise result from the intervention.

6.7.1 Intervention pricing in practice

Intervention pricing is used to determine prices for energy and market ancillary services in every dispatch interval (being five minutes in duration[203]) that AEMO declares to be an "intervention price dispatch interval" in accordance with clause 3.9.3 of the NER. An AEMO intervention event may consist of a large number of dispatch intervals (up to three weeks)[204] and intervention pricing is applied across all these intervals (with prices calculated every five minutes).

Intervention pricing is implemented by running the NEM Dispatch Engine (NEMDE) twice – once to determine dispatch targets (the "base case target run") and once to determine intervention prices for energy and market ancillary services (the "what if run"). This process happens every five minutes. Generators are dispatched in accordance with the "base case target run" but prices produced by that run are ignored for the purpose of setting prices. Dispatch (and spot) prices are instead determined in accordance with the "what if run", but dispatch targets produced by that run are ignored for system operation purposes.

The "base case target run" includes the actions taken as part of the AEMO intervention event – including the issuing of directions or the activation of the RERT, and any counteraction constraints imposed by AEMO in order to minimise the effects of the intervention.[205] For example, AEMO may direct one generator to increase its output, and may constrain down another generator in order to reduce the impact of the direction on interconnector flows etc. If no counteraction is imposed, and all else being equal, the amount of energy exported from that region would likely increase or the amount imported reduce, with flow on effects for participants in other regions. When the counteraction does not perfectly offset the impact of the intervention, resulting price changes can be observed in other regions of the NEM. For example, directions issued in South Australia can impact prices in Queensland.

Where AEMO intervenes in the market in response to a reliability issue (e.g. by issuing a direction following an inadequate market response to a lack of reserve (LOR) condition notice), then AEMO may opt to implement little or no counteraction if measures to offset the impact of the intervention would be contrary to its objective of bringing more capacity on line. For example, the AEMO report documenting the activation of the RERT in Victoria in

202 AEMO, Intervention Pricing Methodology, October 2014, available at https://www.aemo.com.au/-/media/Files/PDF/Intervention-Pricing-Methodology-October-2014.pdf

203 Clause 3.8.21(a1) of the NER.

204 Recent intervention events in South Australia have lasted three weeks: e.g. from 23 April to 14 May 2018.

205 Clause 4.8.9(h)(3) of the NER.

November 2017 notes that, because the activated reserves were unscheduled, no counteractions were practical.[206]

However, there can be instances where reliability-related directions are issued to increase output from one generator and counteractions are implemented to reduce output from other generators.[207] This was the approach adopted in South Australia on 9 February 2017. AEMO issued a direction to bring an additional generating unit online (even though, due to counteractions, total combined output from all generators was broadly the same pre- and post-direction). The result was that a greater number of generators were online and able to increase output in response to rising demand, thereby alleviating the forecast LOR2 condition.[208]

The "what if run" does not include the direction or RERT activation, or any counteractions implemented to reduce their flow on effects. Under the current intervention pricing methodology, both runs use the same inputs, with three exceptions.[209] In the "what if run":

- the initial loading of each unit is set to the dispatch target of that unit from the "what if run" for the previous dispatch interval (while the base case target run will use actual SCADA data); as a consequence, if a unit trips, this will not be reflected in the "what if run" – as occurred when intervention pricing was implemented following a direction on 1 March 2017[210]
- the initial operating mode for each fast start unit is set to the value calculated in the "what if run" for the previous dispatch interval
- the initial load of each interconnector is set to the value in the "what if run" for the previous dispatch interval while the base case target run uses actual SCADA data (so, for example, if a line is de-rated, this will not be reflected in the "what if run")[211]

These differences in inputs mean that "what if" outcomes can diverge from actual outcomes, particularly if the period of the intervention is prolonged.

When an intervention event brings on additional capacity (for example, to alleviate a tight supply demand balance or to address inadequate system strength) and counteractions are not implemented to offset the effect of the direction, the prices produced by the "what if run" will generally be higher than those produced by the "base case target run". This is because the "what if run" will continue to signal the price associated with the supply demand balance as it was prior to the intervention, while prices in the "base case target run" will generally be

206 AEMO, *Activation of unscheduled reserves for Victoria – 30 November 2017*, May 2018, p. 11

207 As noted previously, most directions are issued in response to system security issues and only twice have directions been issued in response to reliability concerns.

208 AEMO, *NEM Event – Direction to South Australia Generator – 9 February 2017*, July 2017, p. 6. 'Lack of reserve 2' (LOR2) signals a tightening of electricity supply reserves and provides an indication to the market to encourage more generation. At this level, there is still no impact to power system security, however AEMO will bring in available additional resources, such as demand response and support generation (such as diesels if required): https://www.aemo.com.au/Media-Centre/AEMO-market-notifications-explained

209 AEMO, Intervention Pricing Methodology, October 2014, p. 4, and SW Advisory & Endgame Economics, op cit, pp 7-8.

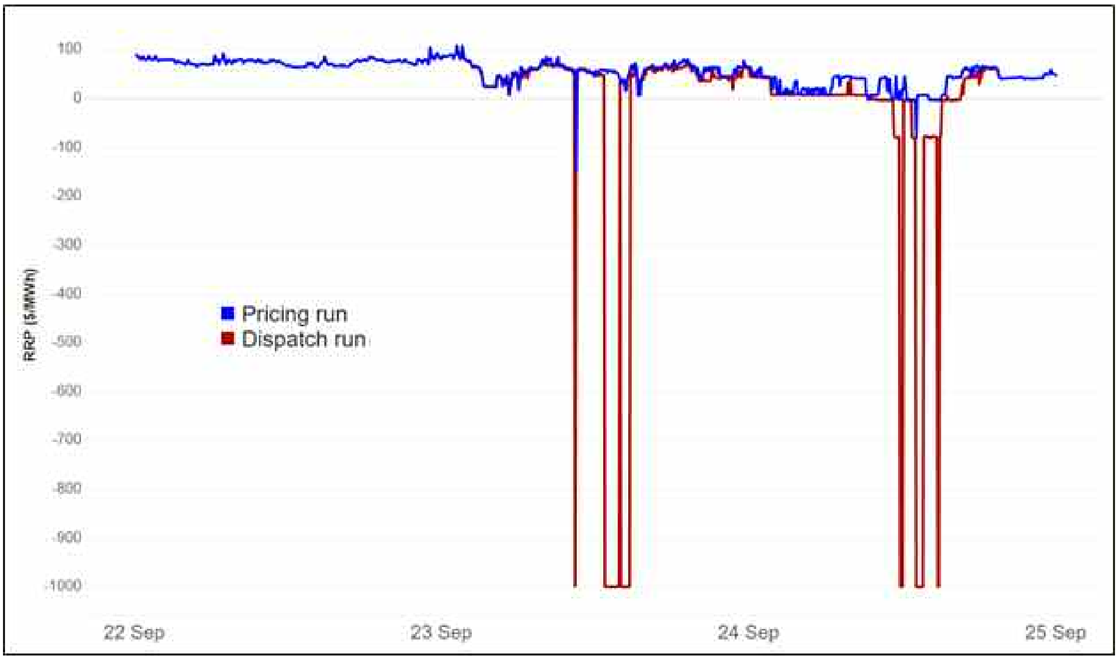
210 SW Advisory & Endgame Economics, op cit, p. 23. The current workaround when this occurs is to stop intervention pricing.

211 Ibid, pp. 7-8.

lower due to the addition of generation capacity. This is not to say that the spot price is being pushed up by the intervention.[212] Rather, intervention pricing is not allowing the price to fall in response to the additional generation coming online.

This effect can be seen in Figure 6.4 which shows that the commencement of the direction did not result in spot prices rising. However, the use of intervention pricing means that the spot price in the "what if" or pricing run does not fall (as it does in the "base case target run" or dispatch run - shown in red) in response to additional generating capacity coming online. This divergence between the "what if run" and the "base case target run" occurs when counteractions are not put in place to reduce the effect of the direction on the supply demand balance. In practice, implementing counteractions in connection with system strength directions in South Australia is difficult when there is limited thermal capacity online, and given the practical difficulty of counter-acting on wind farms.[213]

Figure 6.4: Impact of direction on SA prices - 22-25 September 2017



Source: AEMC analysis of NEM data
Note:

While prices in the "what if" run will generally be higher than those in the "base case target run" or dispatch run, there are occasions when the prices produced by the "what if run" are

212 There have been two anomalous occasions where this has occurred, as discussed in section 6.10.

213 As discussed by the Intervention Pricing Working Group, there are practical difficulties in counter-acting on wind farms. For example, counteractions are implemented manually and counter-acting on wind farms is difficult to manage manually (given their intermittent output) when directions span multiple days. Further, current systems do not support automatic invocation of counteraction constraints. See Meeting 4 slides and associated minutes, available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

lower than those in the "base case target run". This can occur when, early in an intervention event, loads respond to the initially higher "what if" prices by reducing consumption, with the lower demand level then resulting in lower "what if" prices in later dispatch intervals.

Lower "what if" prices can also result from the different input assumptions used in the two runs.

An example of this occurred in South Australia on 25 and 26 April 2017.[214] As noted in the SW Advisory and Endgame Economics report, such an outcome (i.e. "what if" prices that are lower than those produced by the "base case target run") is inconsistent with the concept of intervention pricing.[215]

Interventions in response to inadequate system strength are now a common occurrence in South Australia when low spot prices (associated with low demand and high output from wind farms) make it uneconomic for thermal generators to bid available. In such cases, AEMO relies on directions to ensure that system strength requirements are met. System strength and inertia are services that are not traded in the market - meaning that there is no scarcity of a market commodity that would justify the use of intervention pricing to preserve signals to the market. As there is no scarcity of energy or FCAS in such cases (products that *are* traded in the market), the economic rationale for applying intervention pricing is not present when directions are issued in response to inadequate system strength. This illustrates the issues that arise when a "one size fits all" framework is applied in very different contexts, and is discussed further in section 6.10.

The limited use of counteractions in such cases means that, all else being equal, more energy will be exported to neighbouring regions - resulting in changes to generator output in those regions. As discussed further below, this gives rise to compensation payments to affected participants, the costs of which will generally be borne by customers in South Australia (since the benefit of the direction - creating a secure system - accrues to those customers). This prompts questions as to whether changes are required to mitigate these impacts - for example through changes to the NEM dispatch engine.[216]

6.8 Compensation following intervention events

While intervention pricing is used to set prices for *all* participants in the NEM during an AEMO intervention event, there is also a compensation framework to ensure that participants who have been directed by AEMO to provide services are not out of pocket. This framework is also designed to ensure that participants affected by the direction are in the position that they would have been in but for the direction or RERT activation – thereby minimising market distortion resulting from the intervention. The compensation framework in the NER relates to AEMO intervention events, which includes directions and the RERT. Therefore, when examining the compensation framework holistically we have considered how it applies to

214 This is discussed in SW Advisory & Endgame Economics, *Review of Intervention Pricing - Final Report prepared for AEMO*, 4 October 2017, p. 26.

215 ibid

216 As discussed in the minutes of the Intervention Pricing Working Group meeting on 22 March 2018 - available in meeting pack 5 at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

both mechanisms.[217] A rule change request is currently being considered which seeks to introduce a compensation framework for market suspension events - this is a separate issue and is not discussed further here.[218]

Where AEMO issues a direction, compensation is payable to both "directed participants"[219](those parties to whom the direction was issued) and "affected participants"[220] (those parties who are affected by the direction – for example, a generator the output of which was constrained down to minimise flow on effects from the direction). Where AEMO activates the RERT, compensation is only available to "affected participants" – reflecting that, in relation to the RERT, there are no "directed participants". Instead, the party providing services under the RERT is compensated pursuant to the relevant contractual arrangements.

The NER do not articulate the objective of this compensation framework – in contrast to the administered price period (APP) compensation framework, the objective of which is set out in NER clause 3.14.6(c). That clause states that the objective of the APP compensation framework is to maintain the incentive, during price limit events, for generators (scheduled and non-scheduled) and scheduled network service providers to supply energy, for ancillary service providers to supply ancillary services, and for market participants with scheduled load to consume energy. One stakeholder has suggested that a clearer articulation of the purpose of the AEMO intervention event compensation framework would be beneficial.[221]

"Directed participants" are eligible to receive compensation so that they can recover their costs.[222] In the first instance, a base level of compensation is paid automatically: AEMO adjusts the settlement process so that directed participants are paid for the services they provide pursuant to the direction at the 90th percentile price (calculated by reference to the regional spot price in the preceding 12 months). Directed participants can also lodge a claim for additional costs, including loss of revenue, if payment at the 90th percentile price is not adequate to cover their costs.[223]

We understand that the majority (around 85 per cent) of directed participants have not lodged claims for additional compensation. This may reflect that many are adequately compensated (or, for many, more than adequately compensated) by the 90th percentile price. For example, in South Australia, the 90th percentile price in 2017 was $145. By contrast, the short run marginal costs (SRMC) of the generators who are frequently directed to provide system strength services are well below this level.[224] However, it may also be that some participants who are still out of pocket elect not to incur the administrative cost associated with making a claim for additional costs.[225]

217 Note there are interactions with the *Enhancement to the RERT* rule change request.

218 Further information is available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

219 Clauses 3.15.7 to 3.15.7B of the NER.

220 Clause 3.12.2(a)(1) of the NER.

221 Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016*: *an independent expert report prepared for AEMO,* June 2017, p. 38

222 Clauses 3.15.7 and 3.15.7A of the NER.

223 Clause 3.15.7B of the NER.

224 Based on recent AEMO data, Pelican Point has an estimated SRMC of around $85/MWh, Osborne $85/MWh, Torrens Island A and B $111/MWh and $104/MWh respectively, and Quarantine $115/MWh: AEMO, *Integrated System Plan Assumptions Workbook v2.2* and AEMC analysis.

"Affected participants" are entitled to receive from, or pay to, AEMO an amount that puts them in the position they would have been in but for the direction or RERT activation.[226] Again, the process is automatic in the sense that affected participants need not lodge a claim for compensation. AEMO is required to notify affected participants of the estimated level at which they would have been dispatched had the intervention not occurred, and the trading amount they would have received had the intervention not occurred (less the trading amount already paid to the participant).[227] This additional amount is then incorporated into the participant's final statement for the relevant billing period.[228] An affected participant may dispute the amount payable to them, or payable by them to AEMO, by making a submission to AEMO itemising and substantiating each component of the claim.[229]

No compensation is payable to the affected participant, or payable by that participant to AEMO, if the amount payable is less than $5,000 per trading interval.[230] This threshold also applies to directed participants.[231] The rationale for the threshold is that, if the amount if less than $5,000, this amount is immaterial and does not justify the costs of determining a compensation payment.[232]

While this threshold currently applies to each trading interval, recent stakeholder discussions have explored whether this should instead apply "per intervention event" so that market participants are not adversely affected where an intervention event comprises a number of trading intervals. This is discussed further below.

Compensation costs in respect of directions are funded by market customers, having regard for the relative benefit each region receives as a result of the direction.[233] By contrast, the NER are silent as to who should pay for any compensation to participants affected by the activation of the RERT. [234]This issue may be considered as part of forthcoming rule change processes.

The current use of directions in South Australia raises questions as to whether the compensation framework strikes an optimally efficient balance between, on the one hand, fairly compensating directed parties for their services and, on the other, the level of compensation costs imposed on consumers. For example, is the current compensation framework creating incentives for generators to bid unavailable and await a direction from AEMO, with flow on effects for costs facing consumers? A recent AER compliance report also raises questions about generator behaviour in the lead up to directions being issued and this

225 Anecdotal evidence suggests that the process of seeking compensation for additional costs can be time consuming and costly for directed participants.

226 Clause 3.12.2(a)(1) of the NER.

227 Clause 3.12.2(c) of the NER.

228 Clause 3.12.2(d) of the NER.

229 Clauses 3.12.2(f) and (g) of the NER.

230 Clause 3.12.2(b) and (i) of the NER.

231 Clause 3.15.7B(a4) of the NER.

232 SW Advisory & Endgame Economics, op cit, p. 51

233 Clause 3.15.8 of the NER.

234 The NER does provide for cost recovery in relation to other aspects of the RERT. In particular, AEMO's liabilities under reserve contracts are to be paid for by customers in the region which benefits from the contract – clause 3.15.9(d). Operational and administrative costs incurred by AEMO in relation to the RERT are to be recovered from market participants generally – clause 3.15.9(g). Neither of these provisions relate to costs associated with compensating affected participants.

issue may warrant further consideration in the context of any future discussions regarding system strength requirements in South Australia.[235] As noted earlier, questions also arise regarding the extent of payments to affected participants due to the current difficulties with implementing counteractions in connection with system strength directions.

6.9 Transparency of the compensation process

The degree of publicly available information regarding the AEMO intervention event compensation process varies.

6.9.1 Compensation following directions

Until late 2016, AEMO's post event reports did not identify the directed participant. However since December 2016, these reports do identify the party directed.

In accordance with clause 3.13.6A(b) of the NER, AEMO publishes aggregate data about the compensation payable to directed and affected participants following a direction. [236] However, this data is very high level and does not show how much compensation has been paid to individual directed and affected participants.

The quantum of compensation paid to individual directed and affected participants is only publicly available where an independent expert report has been prepared and that report identifies the directed or affected participant. Such reports are prepared where an independent expert has been engaged by AEMO to assess a claim for additional compensation (beyond that automatically paid to directed participants) or where, in order to compensate a directed participant who provided a service other than energy or FCAS, it is necessary to determine a fair payment price for that service.[237]

Since January 2016, only three such independent expert reports have been prepared.[238] Of these, only one identifies both the participant and the compensation payable.[239]

While the NER do prohibit independent experts from including in their 'fair payment price' report the identity of a directed participant,[240] there is no such prohibition in the clause relating to other independent expert reports (e.g. where a directed or affected participant

235 AER, Quarterly Compliance Report, available at https://www.aer.gov.au/system/files/Quarterly%20Compliance%20Report%20January%20-%20March%202018%20.pdf The AER notes at page 7: "We are currently considering the conduct of some scheduled generators who have advised AEMO of their intention to desynchronise at shorter notice than is required by clause 4.9.7(a) of the Electricity Rules. Further, we are examining whether this has led to AEMO issuing directions to generators to remain synchronised, to ensure the market remains in a secure operating state."

236 Available at http://www.nemweb.com.au/REPORTS/CURRENT/Directions_Reconciliation/

237 See clauses 3.15.7A and 3.15.7B of the NER.

238 Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Market-event-reports While other such reports have been prepared in the past, these are considered outdated and are no longer made available on the AEMO website.

239 Harding Katz Pty Ltd, Compensation for Directions in Queensland on 28 and 29 March 2017, 4 September 2017, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Market_Event_Reports/2017/Final-report—-Compensation-for-Directions-in-Queensland-on-28-and-29-March-2017.pdf There are two further reports. One of these involves estimating a "fair payment price" and, as such, anonymity of the directed participant is required by clause 3.15.7A(5) the NER. The other report is not subject to this requirement however and therefore anonymity does not appear to be warranted.

240 Clause 3.15.7A(c)(5) of the NER.

lodges a claim for additional compensation).[241] As such, the legal basis for the current lack of transparency is not clear.

This practice in relation to directed participants contrasts with the approach to compensating participants who incur loss during an administered price period (a process set out in clause 3.14.6 of the NER). While there has only been one claim made under that framework, the practice adopted was to identify the claimant (together with the quantum of compensation paid), even though there is no explicit legal requirement in the NER to identify the participant.[242]

While it may be possible for an informed stakeholder to access detailed NEM data and apply the 90th percentile price to estimate (based on a number of assumptions) the compensation automatically paid to individual directed participants, it would be difficult if not impossible to estimate the amount of compensation paid to individual affected participants (following the issue of a direction or the exercise of the RERT).

Such payments can be substantial. For example, compensation paid to affected participants following the direction issued in South Australia on 9 February 2017 amounted to approximately $4.3 million.[243] This was paid for by customers in South Australia. This figure is not included in the AEMO report relating to these events (it is not required to be). The cost of compensation associated with the growing number of system strength directions in South Australia is also significant, as shown by the aggregate data made available by AEMO.[244]

While it is not suggested that commercially sensitive information should be made public, greater transparency regarding the directions compensation process may be appropriate, particularly given that consumers pay for compensation costs, and noting the increase in the use of directions in South Australia. This would be particularly useful in considering whether the current compensation framework is incentivising bidding practices that are not optimally efficient, at the expense of consumers. It could also inform deliberations as to whether the current approach to intervention pricing and counteractions is appropriate, particularly in situations where the intervention relates to a service (system strength or inertia) that is not traded in the market. This is discussed further below in section 6.10.

6.9.2 Compensation following RERT activation

In addition to the cost of procuring and activating the RERT, there may be additional costs incurred through the payment of compensation to “affected participants”. As with compensation related to directions, information regarding the payment of compensation in connection with the RERT is similarly limited. While it appears that no compensation was paid in relation to the RERT activation in Victoria on 30 November 2017, $170,000 in

241 Clause 3.12.3(c)(5) of the NER.

242 AEMC, *Final Decision, Compensation Claim from Synergen Power Pty Ltd*, 8 September 2010

243 See D*raft Minutes – Intervention Pricing Working Group – Meeting 1,* p. 4, available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

244 See http://www.nemweb.com.au/REPORTS/CURRENT/Directions_Reconciliation/

compensation was payable in relation to the RERT activation in Victoria and South Australia on 19 January 2018.[245]

The report relating to the latter event notes that "other costs [the column in which the compensation costs are shown] represent the compensation paid to Market Participants due to the intervention event (for example, to compensate for energy generation which is displaced by RERT capacity), and to Eligible Persons due to changes in interconnector flows, and therefore changes in the value of Settlement Residues". No further information is provided as to whether the compensation paid related to displaced generation and/or changes to interconnector flows.

Given that the cost of activating the RERT on that occasion was just over $24 million (taking into account pre-activation and activation costs), more granular data would be useful to inform considerations as to whether the approach adopted delivered least cost outcomes consistent with the National Electricity Objective.[246] For example, if the compensation was paid to displaced generators, such information could inform deliberations regarding the degree to which activation of the RERT was necessary and optimally efficient.

RECOMMENDATION 5:

That AEMO consider how to increase the level of transparency surrounding AEMO intervention events (directions and RERT activation) and resulting compensation payments. This could be achieved through changes to processes adopted by AEMO and their independent expert consultants, and may not necessitate changes to the NER.

6.10 Recent issues with intervention pricing

The application of intervention pricing has resulted in some anomalous and unexpected price outcomes in recent times. One such instance occurred on 9 February 2017, when a direction issued in South Australia resulted in prices in Queensland and NSW reaching the market price cap at a time when such an outcome might not otherwise be expected.[247] The prices produced by the two runs (base case target run and what if run) on that occasion were materially different.[248] This was because a feedback constraint in NEMDE bound incorrectly – resulting in less power flowing north to NSW and Queensland and therefore causing more expensive generators to come on line and push up prices in the "what if run" (though not in the base case target run or real world).[249] A similar incident occurred on 13 January 2018

245 AEMO, Activation of unscheduled reserves for Victoria – 30 November 2017, May 2018, p. 9, and AEMO, Activation of unscheduled reserves for Victoria and South Australia – 19 January 2018, May 2018, p. 9.

246 Total costs associated with the RERT in 2017-18 were more than $51 million, including $26 million in availability payments: AEMO, Summer 2017-18 operations review, May 2018, p. 33.

247 SW Advisory & Endgame Economics, op cit, p. 19.

248 AEMO, NEM Event – Direction to South Australia Generator – 9 February 2017, July 2017, p. 15. While the AEMO report refers to a graph showing intervention prices in NSW and Queensland, the relevant graph is not in fact included. Only intervention price outcomes for Victoria and SA are shown.

249 AEMO Intervention Pricing Working Group, Meeting 2 – 20 December 2017, minutes available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/IPWG/IPWG-F2F—Draft-minutes—-20171220.pdf AEMO has identified that this outcome resulted from the mixing of measured values (from SCADA) and what-if values (produced in the

when binding feedback constraint equations limited interconnector flows resulting in higher prices.[250] (AEMO has commenced consultation on changes to the Intervention Pricing Methodology to address these issues.[251])

The February 2017 incident prompted AEMO to initiate a review of whether the current intervention pricing methodology is fit-for-purpose. To this end, it commissioned a report from SW Advisory and Endgame Economics to review the implementation of intervention pricing and make recommendations to address issues arising.[252] It also established an Intervention Pricing Working Group to review the report and consider whether changes should be made.

The consultants' report notes that, when the Reserve Trader provisions (now the Reliability and Emergency Reserve Trader) were included in the original 1998 National Electricity Code (now the NER), the intention was that the plant offered under a reserve contract or pursuant to a direction would be offered at the market price cap. They note that "at the time, it was not envisaged that there would be something like the current NEM Dispatch Engine (NEMDE) intervention pricing reruns as the mechanism for determining intervention prices."[253]

In reviewing recent intervention events, the consultants note that "in many instances, the services that AEMO has obtained for the power system (e.g. system strength and inertia) are ones for which there is no market. In these circumstances, setting intervention prices in other markets (i.e. for energy and FCAS) may be unnecessary and even counter-productive".[254] The report concludes that the economic rationale for intervention pricing (being to preserve the price signal that would have been provided to the market if AEMO had not intervened) does not apply when there is no relevant market and that AEMO should not use intervention pricing in such cases.[255]

The report recommends that the intervention pricing framework be designed to address only those instances where there is scarcity of traded services (i.e. energy and market ancillary services).[256] It notes that the economic rationale for intervention pricing in such cases is sound.

The consultants note the inherent difficulty in the rerun approach and suggest that any new rerun approach will be susceptible to unintended outcomes "because of the noise that is

previous dispatch interval of the pricing run) in the NEMDE algorithm used for intervention pricing purposes.

250 AEMO Intervention Pricing Working Group, Meeting 3 – 15 February 2018, slides available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group [1] SW Advisory & Endgame Economics, op cit

251 An issues paper has been prepared and is available at: http://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2018/Intervention-Pricing/Intervention-Pricing-Methodology_Issues-Paper.pdf It notes on page 9 that "the anomalous price outcomes in NSW and QLD were a result of overly restrictive limits produced by some feedback constraint equations in the [what if] pricing run. ... The use of measured values for intra-regional flows in computing the RHS of the feedback constraint equations produced overly restrictive limits for some network elements in the pricing run."

252 SW Advisory & Endgame Economics, op cit

253 Ibid, p. 5.

254 Ibid, pp. 9-10.

255 Ibid, pp. 28-29.

256 Ibid, p. 49.

inherently introduced during the exercise".[257] Given this, the consultants conclude that there is merit in adopting an approach to intervention pricing that does not rely on the rerun of the dispatch engine.[258]

Instead, they recommend that, where additional capacity (or load reduction) is brought into the market to address a shortfall – either through the RERT or directions – it should be priced at the market price cap. This would be similar to the approach already adopted when involuntary load shedding occurs pursuant to a clause 4.8.9 instruction. They note that this approach does not require the use of intervention pricing reruns because it preserves the price signal that would have occurred but for the intervention.[259]

A similar approach was also recommended in submissions to the *Reliability Frameworks Review* interim report with respect to the RERT. EnerNOC recommended that the Commission explore setting the spot price to the market price cap for the duration of strategic reserve activation, to preserve investment signals and so that AEMO intervenes as late as possible, thereby minimising market distortions. This was echoed in the Energy Efficiency Council's submission.[260]

Given that reliability-related directions and the activation of the RERT are rare and occur during periods of tight supply-demand balance, implementation of the proposed market price cap approach could be expected to have relatively limited price impacts on consumers. On the other hand, if the price had been at the market price cap for the six hours during which the RERT was activated on 19 January 2018, the cost implications would have been not insignificant.

Regard must also be had for the potential for such high prices to trip the cumulative price threshold and trigger an administered price period. In addition, careful consideration of impacts on bidding behaviour would be important before progressing any such change. Nonetheless, the proposed approach (with its significant benefit of simplicity) may warrant further consideration, particularly if anomalous outcomes from the rerun approach recur.

While the NEMDE algorithm issue which caused the anomalous price outcomes on 9 February 2017 has been identified by AEMO and work is underway to address it, broader questions remain regarding the economic rationale for applying an intervention pricing approach designed with reliability events in mind to situations centred on security concerns and services that are not traded in the market. Further consideration may be warranted as to whether the current "one size fits all" intervention pricing approach is sufficiently nuanced. On the other hand, this may be considered a second order issue – with the primary issue being to address system strength issues and thus reduce the current need to issue directions.

257 Ibid, p. 54.
258 Ibid, p. 54.
259 Ibid, p. 50.
260 See EnerNOC, submission to interim report, p. 7 and Energy Efficiency Council, submission to interim report, p. 18.

6.10.1 The Intervention Pricing Working Group

The Intervention Pricing Working Group (IPWG) was tasked with considering the recommendations in the SW Advisory & Endgame Economics report, as well as discussing any new approaches that had not been considered.[261]

A number of issues and proposed rule changes have been identified.[262] While most proposed changes are administrative in nature, some have important implications. For example, it is proposed that the $5,000 threshold (applicable when calculating compensation for directed and affected participants) should apply not on a "per trading interval" basis, as currently, but on a "per intervention event" basis. This is proposed on the basis that the current threshold reduces the amount of compensation payable, to the detriment of those parties who are directed or affected.

On the other hand, and particularly given the lengthy period of recent intervention events,[263] the proposed change could result in a substantial increase in compensation payments. Given that compensation costs are funded by consumers, this has implications for the NEO. Further analysis would be required to understand the trade-off between the costs facing generators, and the costs that would need to be recovered from consumers if this change were to be made.

Another proposal involves including semi-scheduled generators in the definition of "affected participants", thereby making them eligible to receive compensation when their output is affected as a result of an intervention event. Again, careful consideration will be required to understand the implications of this proposal both for semi-scheduled generators (which typically have low or zero marginal costs) and the consumers who ultimately bear the cost of compensation.

> **RECOMMENDATION 6:**
>
> The AEMC will build on the work that has been done by AEMO through the *Intervention Pricing Working Group* and review the current intervention pricing and compensation framework to make sure that it is sufficiently nuanced to respond efficiently to the variety of contexts in which AEMO intervention events occur. The AEMC will also progress any rule changes submitted to us by AEMO on intervention pricing and compensation framework in conjunction with this Review.

261 Terms of reference are available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/IPWG/Intervention-Pricing-WG_Terms-of-Reference_Final.pdf

262 These are detailed in the meeting papers available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group See in particular item 4.1 in the meeting pack for meeting 5.

263 As noted earlier, one recent intervention in South Australia lasted three weeks: from 23 April to 14 May 2018.

7 ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
ASEFS	Australian Solar Energy Forecasting System
ASX	Australian Stock Exchange
AWEFS	Australian Wind Energy Forecasting System
COAG	Council of Australian Governments
Commission	See AEMC
DER	Distributed energy resources
DNSP	Distribution network service providers
DRM	Demand response
DRSP	Demand response service provider
EAAP	Energy Adequacy Assessment Projection
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
FRMP	Financially responsible market participant
GSH	Gas supply hub
Guarantee	See NEG
LOR	Lack of reserve
MASP	Market ancillary service provider
MSATS	Market settlement and transfer system
NEG	National Energy Guarantee
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National electricity objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National energy retail objective
NERR	National Energy Retail Rules

NMI	National Metering Identifier
OTC	Over-the-counter
PASA	Projected Assessment of System Adequacy
PoLR	Procurer of Last Resort
RERT	Reliability and Emergency Reserve Trader
RoLR	Retailer of last resort
SCADA	Supervisory control and data acquisition
STFM	Short-term forward market
TNSP	Transmission network service provider
USE	Unserved energy

A FACILITATING DEMAND RESPONSE IN THE WHOLESALE MARKET

BOX 5: KEY POINTS

- Demand response refers to consumers of electricity changing their level of consumption in the short term in response to signals to do so.
- The Finkel Panel recommended that the Commission should undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market. We have taken on this recommendation in our *Reliability frameworks review*.
- The ACCC also recommended, in the final report of its Retail Electricity Pricing Inquiry, that a mechanism for third parties to offer demand response directly into the wholesale market should be developed.
- In removing barriers to the utilisation of wholesale demand response the Commission considers it is important to allow flexibility in how a consumer can provide wholesale demand response. The framework for facilitating wholesale demand response should be flexible and resilient enough to remain fit for purpose irrespective of what the future may bring. New products and services for wholesale demand response will have the potential to benefit consumers, but the regulatory framework needs to enable this evolution in line with consumer preferences.
- During the course of this Review, the Commission has considered how to best to facilitate the demand-side, and in particular, demand response in the wholesale market. We have set out a package of recommendations that seek to remove barriers and provide a range of additional tools to help the demand-side attain more price certainty ahead of real time, while preserving the market-based arrangements in the NEM that allow for flexible and resilient frameworks. These recommendations complement each other and act in concert to facilitate demand response in the wholesale market.
- There has been significant interest from multiple stakeholders - representing a range of industry participants - who have noted that they intend to submit a rule change request to the Commission to implement our a way for demand response aggregators to be treated on equal footing with generation i.e. implement a demand response mechanism. The Commission welcomes this - integrating demand response into the wholesale market is a critical component of facilitating the energy sector transition and so we do not consider there should be any delays in progressing this issue. If the Commission has not received a rule change request from one of these stakeholders by the end of August 2018, then it will draft a rule change request that the Energy Security Board can submit.
- In addition, AEMO and ARENA will be trialling “in-market demand response”. The objective of this trial is to demonstrate the potential to increase wholesale market competition by improving access of demand-side resources to spot market pricing. Under the trial, demand response would be provided to the spot market by the customer /

aggregator which displaces the energy which would otherwise have been provided by the marginal generator. As an in-market trial, the majority of the revenue would be earned in the spot market, paid for by retailers and dispersed to demand response providers through the market settlement system.

- Therefore, in order to facilitate increased demand response in the wholesale market, and in response to Finkel Panel recommendation 6.7 we consider that:
  - A voluntary, contracts-based short-term forward market be implemented that would allow participant-to-participant trading of financial contracts closer to real time. This will provide the demand side with more opportunities to lock in price certainty, making it easier for large demand side consumers to engage in the wholesale market and demand respond (i.e. reduce consumption) in response to expected wholesale prices. AEMO should undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market.
  - Demand response providers should be able to be recognised on equal footing with generators in the wholesale market and so being able to more readily offer wholesale demand response in a transparent manner to AEMO. The Commission understands, through their submission to this Review, that TEC and PIAC will submit a rule change request to the AEMC to implement such a mechanism by end of August 2018. If these stakeholders have not submitted a rule change request by this time then the Commission will draft the rule change request for the Energy Security Board to submit. This will be supported by testing the practicability and costs associated with this, with in-market demand response trials being undertaken by AEMO and ARENA.
  - Consumers should be allowed to engage multiple retailers / aggregators at the same connection point (multiple trading relationships). This will promote competition between retailers, supporting new business models for demand response and providing consumers with greater opportunities to engage in wholesale demand response with parties other than their incumbent retailer. Subject to the outcomes of relevant trials, AEMO should develop a rule change request to submit to the Commission to implement multiple trading relationships.

The appendix is structured as follows:

- Appendix A.1 provides background and context for this work stream
- Appendix A.2 provides a summary stakeholder comments made in submissions to the directions paper
- Appendix A.3 sets out our approach to developing our recommendations
- Appendix A.4 sets out an overview of the Commission's proposed approach to facilitating wholesale demand response
- Appendix A.5 presents our recommendation to introduce a voluntary contracts-based short term forward market

- Appendix A.6 presents our recommendation to allow consumers to access multiple service providers behind the same connection point
- Appendix A.7 presents our recommendation for how third parties can sell demand response in the wholesale market.

A.1 Background and context

A.1.1 What is the context for this work stream?

Demand response refers to consumers of electricity changing their level of consumption in the short term in response to signals to do so.

Demand response has been receiving growing attention as a service that will increasingly play a role in the future of the NEM, most notably as an alternative to generation. This is being driven by technological advancements allowing the demand side to become more dynamic, as well as acknowledgement of the need for flexible and dispatchable resources on both the supply and demand side to accommodate the increasing penetration of variable renewable generation. As this transition continues, the demand-side is expected to increasingly participate and contribute to power system reliability. This has been widely recognised in the electricity industry.

Demand response is currently being used by a number of market participants and technology providers in the NEM. Its value has also been highlighted in a range of reports over the last several years, including:

- the Commission's *Power of choice* review (published in 2012)
- the Independent Review into the Future Security of the National Electricity Market ('Finkel Panel review') (2017)
- the Commission's *Strategic priorities* (2015 and 2017)
- Energy Networks Australia and CSIRO's *Electricity network transformation roadmap* (2017)
- the AER's demand management incentive scheme (2017)
- AEMO's *Advice to Commonwealth government on dispatchable capacity* (2017)
- the Energy Security Board's *Health of the NEM* report (2017)
- the Energy Security Board's *National Energy Guarantee: Draft detailed design consultation paper* (2018)
- the Energy Security Board's technical working group paper on demand response (2018)
- AEMO's *Summer operations report 2017-18*. (2018)

The Finkel Panel review placed substantial emphasis on demand response as playing a pivotal role in the future of the NEM. The Finkel Panel review concluded:[264]

- There is a need for adequate levels of dispatchable capacity in the NEM, which includes demand response.

264 Finkel Panel, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, pp. 76, 80, 101.

- Price-responsive demand has a role in reducing demand peaks when wholesale spot prices are high.
- The NEM currently does not have sufficient incentives for encouraging the participation of distributed demand response aggregation services. It may be a low-cost and under-developed opportunity for maintaining reliability.

Of particular relevance is the Finkel Panel recommendation 6.7:[265]

> "The COAG Energy Council should direct the Australian Energy Market Commission to undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market. This review should be completed by mid-2018 and include a draft rule change proposal for consideration by the COAG Energy Council."

Accordingly, when the Commission commenced this review it committed to a consideration of further facilitation of demand response in the wholesale energy market in accordance with the Finkel Panel recommendation.

It is important to recognise that there are different types of demand response: wholesale, emergency, network and ancillary services. While the equipment that provides these different types of demand response are often the same, the services provided are separate. While wholesale demand response and ancillary service demand response participate on a wholesale level, network demand response and emergency demand response do not. There are also clear interactions between these different types of demand response as shown in the table below.[266]

The ACCC has also highlighted these interactions, noting that there are coordination issues to consider when it comes to demand response participating in different markets - e.g. high spot prices (which may incentivise wholesale demand response) may not occur at the same time as localised network issues.[267] It should also be noted emergency demand response typically sits outside of the market.

Table A.1: Four types of demand response in the NEM

TYPE	DESCRIPTION	CURRENT STATUS	WHERE IS IT BEING CONSIDERED?
Wholesale demand response	Market-driven demand response used to change the quantity of electricity bought in the wholesale market in response to	Due to the lack of transparency around how much wholesale demand response is currently being utilised, it is difficult to draw	This review.

265 Ibid, p. 25.

266 For example, the interactions between wholesale and emergency demand response are being considered in the *Enhancement to the RERT* rule change request.

267 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

TYPE	DESCRIPTION	CURRENT STATUS	WHERE IS IT BEING CONSIDERED?
	wholesale prices, or to help market participants manage their positions in the contract market.	firm conclusions about how much demand response is occurring in the NEM, or whether this level is efficient.	
Ancillary service demand response	Demand response employed for providing ancillary services. For example, responding quickly to brief, unexpected imbalances in supply and demand by participating in the frequency control ancillary service (FCAS) markets.	Large energy users have used demand response to provide FCAS. Market ancillary service providers (MASPs) can offer customers' loads into FCAS markets. Currently, there are two MASPs using demand response to provide FCAS.	*Frequency control frameworks review.*
Emergency demand response	Demand response employed as an emergency lever by the system operator during supply emergencies, the service being centrally dispatched or controlled to avoid involuntary load shedding. This is generally provided by out-of-market reserves.	Demand response can – and currently is – participating in the RERT.	This review. *Reinstatement of long-notice RERT* rule change. *Enhancement to the RERT* rule change. AEMO-ARENA demand response trial.
Network demand response	Demand response employed to help a network business to provide network services to consumers.	The existing regulatory framework provides a number of incentives and obligations for non-network options (including demand response) to be adopted where it is efficient to do so e.g. the Demand	Demand management incentive scheme. Demand management incentive allowance.

TYPE	DESCRIPTION	CURRENT STATUS	WHERE IS IT BEING CONSIDERED?
		Management Incentive Scheme that provides DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.	

Given the Finkel recommendation, as well as the fact that wholesale demand response is the least facilitated in the NEM, we will focus on wholesale demand response for the remainder of this chapter.

Similarly, the ACCC report into Retail Electricity Pricing Inquiry, published on 11 July 2018, recommended developing a mechanism for wholesale demand response for third parties to offer demand response directly into the wholesale market.[268] It recommended that design of the mechanism should commence immediately and should build on the work undertaken in this Review.[269]

The ACCC noted that it supported the development of a mechanism for third parties to offer demand response directly into the wholesale market, due to its potential to limit the need for additional generation and its potential to put downward pressure on price.[270] One of its reasons for doing so is that third parties that specialise in the provision of demand response services and that have identified market opportunities without the need for incentive payments is more likely to result in an efficient level of these services being provided.[271] It also noted that retailers would continue to be able to develop demand response products.[272]

A.1.2 How do consumers currently engage in wholesale demand response?

Wholesale demand response is market-driven demand response used to change the quantity of electricity bought in the wholesale market in response to wholesale prices, or to help market participants manage their positions in the contract market. To provide wholesale demand response, a consumer must be exposed to the wholesale price for electricity, either directly or through an intermediary, and must be able to change their exposure by changing their level of consumption in response to price.

268 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

269 Ibid. p. 205.

270 Ibid. p. 204.

271 Ibid, p. 204.

272 Ibid. p. 204.

Under the current arrangements

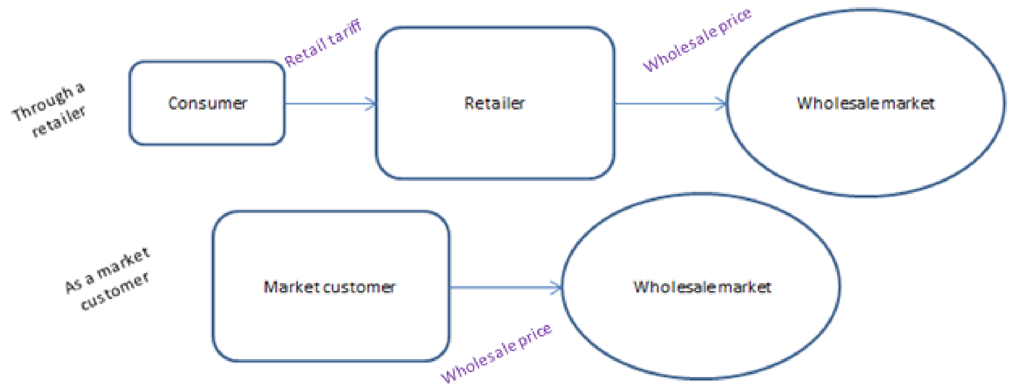
Currently, a consumer sees the wholesale price either directly as a market customer, or indirectly through a retailer.

A market customer sees price signals that enable it to respond to wholesale prices in line with its willingness to consume at different prices.

Energy retailers must source supply from the wholesale market. The spot market price is currently set every 30 minutes, and can fluctuate greatly depending on the conditions in the market in a given trading interval.

There is a mismatch between the way most retailers purchase electricity and how they recover the costs from their customers. The wholesale price of electricity changes every 30 minutes and can vary greatly. Small customers are generally charged a fixed rate for their energy consumption for a period of time (typically, 12 months) and are billed at regular periods (for example, monthly or quarterly). Energy retailers manage the risks associated with wholesale market volatility through the purchase of hedging products on the contract market and through vertical integration with generators.

Figure A.1: Wholesale demand response under current arrangements



The arrangements for providing other types of demand response can involve different parties.

Because demand response is energy that is not consumed or energy that is curtailed, under current arrangements, demand response is primarily through energy retailers (or as mentioned, consumers may be able to participate directly in demand response by becoming a market customers. In some circumstances, it may be commercially beneficial for market customers, including retailers, to offer demand response, to the extent that load curtailment may, for example, offset their exposure, if any, to wholesale spot prices.[273]

273 See, for example, ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

The ACCC has noted that current arrangements are a limitation due to the lack of an explicit price paid for demand response offered in the wholesale market.[274] As discussed in the directions paper, this limitation is due to the fact that there can only be one FRMP at each connection point, i.e. each consumer can only have one retailer for each connection point, meaning that "demand response" cannot be disagreggated from energy consumption by a third party.

However, third parties are able to participate at present. Under the current arrangements, a third party *can* offer wholesale demand response services to a consumer and to retailer but because the third party has no exposure to the wholesale market, they must enter into an agreement with a participant that is exposed e.g. a retailer or a market customer.

Therefore, it can be difficult for third parties (i.e. parties who are not retailers or another form of market customer) to capture the value associated with wholesale demand response under the current framework because the benefits of wholesale demand response accrue to the retailer or market customer through lower exposure to high wholesale prices, and there is no regulated mechanism by which that can be shared with a third party.

This is supported by the ACCC, which noted that third party providers can only benefit from demand response services through retailers, and that these third party providers have stated that there are commercial barriers to partnership with retailers.[275]

Proposed market changes

As flagged by the ACCC, there are a number of changes and potential proposed changes under way in other parts of the energy sector that could facilitate the role of demand response in the wholesale market. These are:[276]

- the National Energy Guarantee and in particular, in the event that the reliability requirement is triggered, requiring retailers to comply with it, including through demand response
- the implementation of five-minute settlement, which may incentivise investment in fast-response options in order to capture any potential benefits of flexibility brought about by the move from 30 minutes to five.

Price certainty and forecasts

Wholesale demand response involves the altering of consumption in response to wholesale prices. Demand response resources undertake decisions that are similar to the unit commitment decisions of generators participating in the wholesale market. They must make decisions to change their level of consumption at a particular time based on their expectations of future wholesale prices at that time. Forecasts of future prices assist decision making regarding shifts in demand or reducing consumption of electricity in industrial/commercial processes with a long lead time.

274 Ibid. p. 202.
275 Ibid. p. 202.
276 Ibid. p. 201.

However forecasts can only assist participants in forming their expectations of future outcomes. They do not guarantee value for consumers committing to demand response ahead of real time.

Consequently, consumers also need some degree of certainty of future prices to undertake demand response. Certainty improves with firmer expectations of future prices and through the use of tools such as financial derivatives. Contracts allow participants to transfer (or take) some of the risk associated with price uncertainty to a contract counterparty.

Alternatively, a consumer can outsource the challenges and risks associated with trying to anticipate future wholesale prices. A third party can take on the uncertainty of making decisions based on forecast prices and manage this risk through financial tools.

Firm v/s non-firm wholesale demand response

It is important to recognise that there are different types of wholesale demand response:

- Firm and fast acting wholesale demand response requires time, education and equipment to develop - it is this type of demand response that can be considered dispatchable and so the reduction in output can be in response to a particular instruction.
- In contrast, there is non-firm wholesale demand response that can be utilised without investing as much time or resources, but the extent of this demand response is likely to be both less firm and more variable e.g. consumers may receive voluntary prompts to reduce consumptions but are able to elect whether they will do so.

A.1.3 What are the current levels of demand response in the NEM?

There is a lack of transparency about how much wholesale demand response is currently being utilised in the NEM and so it is difficult to draw firm conclusions on how much demand response is occurring, and on whether the current level of demand response is efficient.

While some stakeholders have suggested that demand response has been limited in the NEM, others have suggested that it is present in substantial quantities that are not visible to the rest of the market. This makes it difficult to determine how much wholesale demand response occurs and where it occurs.

Stakeholder comments indicate that an increasing number of large consumers have entered into arrangements where they have the incentive to respond directly to changes in the wholesale price. However, there is no data on how "large", "large" is. We have been informally advised by stakeholders that energy users with capacity of greater than about 5 MW[277] are generally able to take wholesale price exposure and undertake wholesale demand response - but whether they actually do so, or not, is unclear.

The Commission made a final rule that sought to improve the quality of information on demand side participation in the NEM. Under the final rule, which was published in 2015, registered participants in the market are required to provide information on demand side participation to AEMO, in accordance with guidelines.

277 This size is highly dependent on the type of load and the internal expertise of the energy user.

This has now been implemented through the creation of AEMO's demand-side participation portal.[278] The data provided through this process is expected to provide greater visibility of demand-side resources that are price sensitive, and so those which are engaging in wholesale demand response.

The information provided to AEMO through the portal should include:[279]

- contractual arrangements between a registered participant and a person, in which they agree to the curtailment of non-scheduled load or the provision of unscheduled generation in specified circumstances.
- non-contractual arrangements entered into between a registered participant and a person, or between two registered participants in relation to demand response.

The information sought by AEMO is relatively detailed and should provide greater transparency regarding the extent of wholesale demand response in the NEM. This information is important in being able to draw conclusions on the efficiency of the level of demand response levels system wide.

Market participants were required to submit their data to the online portal by 30 April 2018. However, more than half of the total expected responses regarding demand side participation were not received.[280] The Commission considers that this lack of response is disappointing, and is therefore encouraged that the AER, in its compliance role, intends to work with AEMO to review the performance of participants' obligations with respect to providing demand side information into this portal.

A.1.4 Contribution of demand response to reliability

In many instances, wholesale demand response can more efficiently contribute to reliability than building new generation. This is particularly true when a tight supply-demand balance is only forecast to occur for a short period of time. An active demand-side, characterised by the presence of wholesale demand response, promotes efficient consumption of electricity in the wholesale market.

Where load can effectively respond to prices, it can "choose" its level of consumption based on its willingness to pay for consuming electricity compared to the cost of that electricity. That is, consumers are able to express their individual value of reliability. In a tight supply-demand balance, high prices would encourage an active demand-side to reduce consumption and maintain the reliability of the power system.

A.1.5 What did the directions paper say on wholesale demand response?

In the directions paper, the Commission highlighted limitations and challenges that could be considered as possible barriers to facilitating greater amounts of demand response in the wholesale market. These aspects were:

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278 AEMO's demand side participation portal collects information on demand side participation from electricity market participants for the purposes of informing AEMO's load forecasts under the NER.

279 AEMO, *Demand side participation information guidelines*, July 2017, p. 5.

280 AER, Quarterly compliance report: National electricity and gas laws, 1 January - 31 March 2018, May 2018.

- Enabling demand response from smaller customers is technically difficult and has an upfront cost. While the extent of this technical difficulty and cost appears to be subsiding, the rate of uptake of enabling technology (e.g. smart meters) may limit the development of wholesale demand response from smaller customers, despite it being increasingly technically feasible.
- Uncertainty for providers of wholesale demand response as to whether they can recover the upfront costs of enabling this demand response.
- There is only one financially responsible market participant (FRMP) for each connection point.[281]
- Challenges for new retailers using wholesale demand response to acquire customers and become established in the market.

We considered the first two factors relate more to the commercial and technological challenges associated with efficiently eliciting wholesale demand response. As such, they do not require changes to regulatory frameworks and we have not focussed on these.

BOX 6: EXAMPLES OF DEMAND RESPONSE IN THE NEM

A number of parties in the NEM have overcome the commercial and technological barriers that may have previously been an impediment to demand response. Some examples include:

- EnerNOC has developed a portfolio of loads which it uses to provide FCAS. By aggregating demand responsive loads, EnerNOC has become an active provider of contingency FCAS services.
- Flow Power is a retailer that provides consumers with opportunities to undertake demand response.
- Reposit has partnered with some retailers to provide consumers with credits when their batteries respond to high wholesale prices.

These examples demonstrate that commercial and technical challenges associated with demand response are being overcome and it is an increasingly cost effective service employed by some parties operating in the NEM.

Of the factors influencing the uptake of wholesale demand response in the NEM, there are two that the Commission proposed could be addressed through changes to the regulatory frameworks:

- the requirements for there to be a single FRMP at a connection point
- the challenges faced by retailers offering demand response products.

281 Under the current arrangements allow only a single FRMP at a connection point. Unless a customer is willing to directly participate in the wholesale market or has a retailer that is willing to offer demand response (either from itself, or via a third party aggregator), the customer will not be able to engage in wholesale demand response.

In order to address these issues, three options were presented in the directions paper, two which sought to address challenges associated with a single FRMP at a connection point, and one that sought to address challenges faced by retailers offering demand response products:

1. Transferring the value of wholesale demand response from the FRMP to a third party. That is, a third party would be able to capture the value of wholesale demand response from the existing FRMP (in the directions paper, this was option 1A[282] and 1B[283]).
2. Allowing a third party to assume responsibility for demand responsive load. That is, a third party would be able to more easily become the FRMP for resources that are flexible and dispatchable, including for example controllable loads and batteries (Option 2).
3. Increased incentives for retailers to offer wholesale demand response. This would entail an additional incentive to retailers to provide demand response, with the incentive funded by other retailers (Option 3).

We sought stakeholder feedback on each of these options. Stakeholder feedback on these is discussed below.

A.2 Stakeholder views on directions paper

A.2.1 Overview

Wholesale demand response received substantial attention from stakeholders.

Consistent with stakeholder feedback over the course of this review, support for the introduction of a mechanism to facilitate demand response remained polarised.

The sentiment of stakeholder submissions generally fell into three groups:

1. One group (typically third party demand response providers, technology providers, consumer groups and large energy users) supported the introduction of a mechanism, with the majority being most supportive of a mechanism that transfers the value of demand response to a third party.
2. Another group (majority of incumbent retailers and generators) generally did not consider there was a need for a mechanism to be introduced. These stakeholders highlighted existing retail innovation in providing demand response and suggest a mechanism would distort the market and impose costs on consumers.
3. The last group (some incumbent retailers and other participants) indicated some support for the Commission to undertake further work but cautioned against making changes that would undermine the existing regulatory frameworks

In submissions to the directions paper, Total Environment Centre and Public Interest Advocacy Centre indicated that they intend to submit a rule change request in relation to wholesale demand response.[284] The Energy Efficiency Council noted that the rapid

282 A method that involved a centrally determined baseline.

283 A method that involved participants setting their baselines.

284 Both referred to an unnamed third proponent of a potential rule change request. Submissions to directions paper: Total Environment Centre, p. 3; Public Interest Advocacy Centre, p. 1.

development of a mechanism to facilitate wholesale demand response is essential to rebuild trust in the governance of the NEM.[285]

A.2.2 Role for wholesale demand response

A number of parties emphasised the role of demand response in the future of the NEM.[286] For example, the Australia Institute highlighted the growing number of consumers looking to engage in demand response.[287] Similarly, the Energy Efficiency Council noted that the evidence suggests the level of demand response in the NEM is well below both the economically optimal level and the level seen in overseas markets.[288]

The Australian Energy Council considered the most appropriate role for third party aggregators in the NEM was to actively manage retailers' and networks' customers to limit exposure to high wholesale prices and network congestion respectively.[289]

Some parties commented on the interactions between different types of demand response:

- Energy Networks Australia, Energy Queensland and TransGrid all noted the role that networks can play in providing demand response, and the implications of this.[290] For example, Energy Queensland noted the need to better understand local network constraints which could otherwise prevent consumers with distributed energy resources participating in demand response.[291]
- The Clean Energy Council considered that where practicable, demand response should be incentivised to partake in regular wholesale market operations and not solely as an off-market safety net measure such as the RERT or a strategic reserve mechanism.[292]

CS Energy submitted that demand side participation was the best option for managing low probability reliability events. It also provided analysis which concluded that scheduled demand side participation was not a direct reliability mechanism.[293]

A.2.3 The need to facilitate demand response

A number of stakeholders supported ways to facilitate demand response in the wholesale market.[294] For example, the Energy Users Association of Australia and the Major Energy Users noted that their members could have more opportunities to provide demand response.[295]

285 Energy Efficiency Council, submission to directions paper, p. 2.

286 Hydro Tasmania agreed that demand response would play an increasing role in the future of the NEM; similarly both ERM Power and Infigen Energy supported measures to encourage more demand response; however, Infigen Energy cautioned against making changes at a time when the demand response sector is experiencing significant growth. The South Australian Government stated that it recognises the potential for demand response to reduce peak demand and take pressure off prices.

287 The Australia Institute, submission to directions paper, p. 9.

288 Energy Efficiency Council, submission to directions paper, p. 2.

289 Australian Energy Council, submission to directions paper, p. 4.

290 Submissions to directions paper: TransGrid, p. 4; Energy Networks Australia, p. 6.

291 Energy Queensland, submission to directions paper, p. 8.

292 Clean Energy Council, submission to directions paper, p. 3.

293 CS Energy, submission to directions paper, p. 3.

294 Submissions to directions paper: EUAA, p. 1; CSR, p. 1; S & C Electric, p. 4; Clean Energy Council, p. 3; Tesla, p. 1; The Australia Institute, p. 9; Major Energy Users, p. 4; Zen Ecosystems, p. 1; Energy Efficiency Council, p. 5.

295 EUAA, submission to directions paper, p. 1; Major Energy Users, submission to directions paper, p. 4.

Some stakeholders noted barriers to demand response, and stated that increasing the ways that demand response could be provided would help:[296]

- Zen Ecosystems noted that, as an aggregator looking to create new values streams for its customers, value in the wholesale market was difficult to access and pursuing new value streams would require the creation of bespoke commercial arrangements.[297]
- The Total Environment Centre considered that barriers may be cultural and practical, rather than just regulatory.
- EnerNOC agreed with the barriers presented by the Commission.[298]

However, a number of stakeholders did not consider there was a need for changes to the regulatory frameworks to permit greater demand response in the wholesale market.[299] For example, the Australian Energy Council found that the directions paper appeared to pre-suppose that demand-side response in the NEM was below the efficient level.[300] It noted that this is yet to be empirically demonstrated and that it believed demand-side response may be more prevalent than is generally assumed as a result of being effectively invisible to AEMO and the market. Similarly, EnergyAustralia considered that the factors that had lead the Commission to not introduce the previously considered demand response mechanism were unchanged.[301]

Meridian Energy considered there to be no barriers to development of demand response, and encouraged the Commission to make sure that any further developments designed to encourage demand response do not have the opposite effect of discouraging the very significant retail innovation already underway by both large and small players.[302] Flow Power also highlighted the growing numbers of retailers and consultants facilitating demand response as evidence of demand response occurring within the existing framework.[303]

A.2.4 Transferring value to a third party (option 1A in the directions paper)

As noted above, a group of stakeholders supported this option.[304]

EnerNOC supported the proposal to schedule demand response. In relation to this proposal, it noted:[305]

- that the demand response participating in FCAS markets is effectively scheduled

296 Hydro Tasmania also supported further exploration of options for facilitating wholesale demand response, noting while this is complex, a successfully implemented framework would provide benefits to the market as a whole.

297 Zen Ecosystems, submission to directions paper, p. 1.

298 EnerNOC, submission to directions paper, p. 1.

299 Submissions to directions paper: Flow Power, p. 2; EnergyAustralia, p. 3; Snowy Hydro, pp. 2-3; ERM Power, p. 10; CS Energy, p. 8; Australian Energy Council, p. 4; Meridian Energy, p. 2.

300 Australian Energy Council, submission to directions paper, p. 4.

301 EnergyAustralia, submission to directions paper, p. 3.

302 Meridian Energy, submission to directions paper, p. 2.

303 Flow Power, submission to directions paper, p. 2.

304 Submissions to directions paper: EnerNOC, p. 8; CSR Limited, p. 2; Tesla, p. 2; Energy Users Association of Australia, p. 2; Major Energy Users, p. 5; The Australia Institute, p. 12; Zen Ecosystems, p. 1.

305 EnerNOC, submission to directions paper, pp. 6-8.

- the full suite of obligations that accompany scheduling in the wholesale market may not be appropriate for demand side resources
- the expected changes to retailer billing systems was expected to be minimal as they can accommodate similar arrangements from embedded networks
- it would address the risk of retailers investing in demand response and having those customers changing retailer before the retailer is able to recoup the upfront costs.

Similarly, Zen Ecosystems considered this option would allow it to expand its business model and noted it would be suited to being scheduled in the wholesale market.[306] CSR Limited and Tesla also supported the option to be a way to allow consumers to access the wholesale market.[307]

The SA Government also supported this option, stating that there is value in further developing option 1 and building on the previous work done in this space and through the ARENA-AEMO RERT trial.[308]

Major Energy Users supported this option but noted that end users may experience difficulty being scheduled.[309]

On the other hand, Snowy Hydro considered this option was a solution looking for a problem. Snowy considered that there are sufficient incentives for demand response and found this option to be distortionary and costly. It noted that separating demand response from the retail energy supply without understanding the extent to which demand response is being underutilised would unnecessarily require significant changes to market design.[310]

CS Energy considered this option would reduce economic surplus, is administratively complex and requires paying for unproven, unmetered consumption.[311] ERM Power considered this option has been exhaustively examined in in the *Demand response mechanism and ancillary services unbundling* rule change and that some of the major issues, such as how to accurately develop baselines, had not been resolved.[312]

The Australian Energy Council and Infigen Energy noted that developing accurate baselines is likely to become increasingly difficult e.g. as the amount of demand response grows.[313] Flow Power noted that the development of a baseline posed a major issue.[314]

Snowy Hydro did not support the use of a baseline because it considered this would:[315]

- constitute a regulatory intervention
- compromise the current market design and pricing signals

306 Zen Ecosystems, submission to directions paper, p. 1.
307 CSR Limited, submission to directions paper, p. 2; Tesla, submission to directions paper, p. 2.
308 SA Government, submission to directions paper, p. 6.
309 Major Energy Users, submission to directions paper, p. 5.
310 Snowy Hydro, submission to directions paper, pp. 2-3.
311 CS Energy, submission to directions paper, p. 6.
312 ERM Power, submission to directions paper, p. 10.
313 AEC, submission to directions paper, p. 4; Infigen, submission to directions paper, p. 5.
314 Flow Power, submission to directions paper, p. 2.
315 Snowy Hydro, submission to directions paper, p. 10.

- distort contract/financial markets
- be open to gaming through the baseline
- have potentially significant implementation costs.

Tesla considered the development of baselines would be complex but could be managed through customer trials and stakeholder consultation.[316]

Similarly, EnerNOC noted that work was being undertaken to understand the applicability of baselines from the AEMO-ARENA RERT trial and suggested that this work inform the design of a mechanism.[317]

A.2.5 Singaporean style demand response model (option 1B in the directions paper)

Only several stakeholders commented on this model. EnerNOC did not consider the Singaporean model[318] as appropriate for the NEM because:[319]

- Demand response does not earn the spot price in the Singaporean mechanism (instead, it is paid for on the basis of reductions in spot price) which complicates the ability for a provider to determine revenue prior to dispatch.
- A provider would be required to schedule loads constantly which would prevent participation from volatile loads.

ERM Power noted that there may be some value in considering the Singaporean model further but noted that it would represent a significant shift in the market design.[320] Infigen Energy suggested this model should be considered further but cautioned that it presented opportunities for gaming and increased costs for consumers.[321] SA Government stated that while this option could facilitate customers electing to have spot price pass-through arrangements, there would likely be barriers to this option, such as the cost of establishing a second connection point and the technical feasibility of separate metering.[322]

A.2.6 Transferring responsibility to a third party (option 2 in the directions paper)

As noted above, a group of stakeholders supported this option. For example, EPC Technologies supported this proposal as it considered this would promote innovation and efficiency but would not add complexity or cost to the NEM.[323]

Zen Ecosystems did not consider this option would reduce barriers to entry in the demand side of the NEM.[324] Both EnerNOC and the Total Environment Centre considered this option to be less preferable to Option 1A.[325] EnerNOC attributed this to the following reasons:

316 Tesla, submission on the directions paper, p. 2.
317 EnerNOC, submission to directions paper, pp. 7-8.
318 As discussed in the directions paper. See: AEMC, *Reliability frameworks review*, directions paper, p. 134, April 2018.
319 EnerNOC, submission to directions paper, pp. 10-11.
320 ERM Power, submission to directions paper, p. 10.
321 Infigen Energy, submission to directions paper, p. 5.
322 SA Government, submission to directions paper, p. 8.
323 EPC Technologies, submission to directions paper, p. 2.
324 Zen Ecosystems, submission to directions paper, p. 2.
325 Submissions to directions paper: Total Environment Centre, p. 3; EnerNOC, pp. 11-12.

- Third parties using this design to undertake demand response would need to become retailers and be responsible for purchasing energy from the wholesale market. The third party would need to post prudentials, obtain a retail billing system and undertake the other retailing functions.
- It is currently possible through the embedded networks framework
- It would not facilitate third parties being able to sell risk management products
- It would not avoid costs associated with installing revenue meters and any re-wiring that would need to be undertaken.
- A customer would need to engage with two retailers, doubling a customer's administrative costs.

CS Energy, ERM Power and Energy Networks Australia were open to further consideration of this option if it were seen to be cost effective.[326] However, Infigen Energy suggested the benefits were unclear, particularly given the aggregator would also need to register as a retailer.[327] Flow Power noted that this could result in unnecessary costs being imposed on retailers and consumers.[328] Hydro Tasmania noted that this could raise some potential issues with retailers' obligations to meet various consumer protection requirements.[329]

A.2.7 Retailer incentive fund (option 3 in the directions paper)

This option was generally not supported by stakeholders.[330]

The Australian Energy Council cautioned against this option as it considered the option to be distortionary and not technology neutral.[331] The Total Environment Centre did not support this option because it created the impression of demand response being uneconomic.[332]

Hydro Tasmania suggested that there may be merit in considering ideas to foster innovation and provide benefit to consumers.[333]

A.2.8 AEMO and ARENA joint submission

AEMO and ARENA submitted a joint submission to the review.[334] In it, the two organisations noted:

- Demand response, and more generally distributed energy resources, need to be valued as a resource that can provide a range of energy, ancillary, and network services. This value can best be unlocked through competitive markets to ensure efficient demand side investment and operation.[335]

326 Submissions to directions paper: ERM Power, p. 10; Energy Networks Australia, p. 5; CS Energy, p. 8.
327 Infigen Energy, submission to directions paper, p. 5.
328 Flow Power, submission to directions paper, p. 2.
329 Hydro Tasmania, submission to directions paper, p. 3.
330 Submissions to directions paper: TransGrid, p. 4; EnerNOC, p. 12, Flow Power, p. 2; Snowy Hydro, p. 10; Australian Energy Council, p. 4; Total Environment Centre, p. 3.
331 Australian Energy Council, submission to directions paper, p. 4.
332 Total Environment Centre, submission to directions paper, p. 3.
333 Hydro Tasmania, submission to direction paper, p. 3.
334 AEMO and ARENA, submission to directions paper.
335 Ibid, p. 2.

- Options 1 and 2 could play a role in encouraging more price responsive loads to participate in the NEM - both would encourage access to the wholesale market.[336]
- There was merit in trialling both Option 1 and 2 in a market context.[337]
- in respect of Option 3, it would not offer the potential to lower transaction costs for market participation in the same way as other options.[338]

In regard to undertaking trials, the submission noted that a program was being developed to test demand response (both aggregated and individual commercial and industrial customers) participation in the wholesale market. It was noted that this could test different approaches to settlement, scheduling and forward commitment.[339]

The submission also providing some learnings from the AEMO-ARENA demand response RERT trial. Some key points were:

- Each of the participants in the ARENA-AEMO demand response trial undertook testing of their response capacity. While overall, the results were positive there was a wide variation of test performance between participants.
    - One participant achieved 227% of its contracted capacity
    - four out of 10 achieved within 10% of their contracted capacity
- It was noted that some challenges were experienced with baselines, particularly in relation to demand response that relies on consumer behaviour change.[340]
- Feedback from trial participants was the baseline method was not suitable for non-variable loads or those with solar PV.[341]
- The strong participant response to the AEMO and ARENA process together with the AEMO RERT tender indicates there is significant latent price responsive demand in the NEM.[342]

A key issue raised by third parties, and retailers participating in the trial, was the ability to access meter data from distributors or retailers even though they had customer consent.[343]

A.2.9 Short-term forward market

The directions paper did not directly discuss a short-term forward market. However, we received some comments on these topics from stakeholders in their discussion of ahead markets that suggested that some participants, particularly on the demand side, would be supportive of a short term forward market.

AEMO's submission supported the introduction of a short-term forward market that it would operate. The reasons given are:

336 Ibid.
337 Ibid, p. 3.
338 Ibid, p. 2.
339 Ibid, p. 3.
340 Ibid, p. 9.
341 Ibid, p. 10.
342 Ibid, p. 9.
343 Ibid, p. 10.

- A short-term forward market may facilitate greater demand response as it would enable demand response providers to pre-commit ahead of time with added price certainty.
- A short-term forward market may provide market participants with better information.
- The short-term forward market may not solve security-related issues (such as directions to maintain system strength in South Australia) but it could provide complementary value by providing greater certainty around contracting for dispatchable generation and would provide greater price certainty to the market.[344]
- Although the information could not be used directly by AEMO in its dispatch engine, a liquid short term forward market would provide additional insight to AEMO on the forward position of generators to inform market operations and dispatch. Currently AEMO's visibility on contract positions is limited to pre-dispatch and ST-PASA.

Several submissions commented on the potential for ahead markets or short-term trading to facilitate increased levels of wholesale demand response in the NEM. For example, S&C Electric, BlueScope Steel, the South Australian government and CSR Limited noted that it could help promote demand side response.[345] Infigen Energy also considered that voluntary financial markets may deliver efficiency benefits through short-term trading and allowing better alignment between gas and electricity markets. The submission supported further consideration of the benefits of a short-term forward market.[346]

On the other hand, some submissions to the directions paper were not in favour of the introduction of a short-term forward market. The generator group submission was not in favour of the introduction of a short-term forward market.[347] This was based on the fact that shorter-term trading has not developed on its own despite there being no barriers to such products being traded, if there was sufficient demand for them. The report concluded that such a trading tool is simply not required as the NEM has a liquid and deep financial market for contracts.

ERM Power noted that although a centrally-coordinated day-ahead trading platform may not currently exist there is nothing in the current NEM design that prevents day ahead or even on day trading of hedge contracts between counterparties should the need exist.[348]

Aurora Energy's submission was not in favour of introducing a short-term forward market.[349] This is because the cost associated with introducing such a market would outweigh the benefits, given that a clear problem with the current arrangements has not been identified.

A.3 Approach to developing recommendations

When considering the Finkel recommendation to facilitate demand response in the wholesale market, the Commission is required to do so in a manner that would advance the NEO. That

344 The issue of using a US-style day-ahead market to assist with security outcomes is discussed further in section XX.

345 S & C Electric, submission to directions paper, p. 3; CSR Limited, submission to directions paper, p. 2; BlueScope Steel, submission to directions paper, p. 3; Government of South Australia, submission to directions paper, p.3.

346 Infigen, submission to directions paper, p. 3.

347 The Generator Group, submission to directions paper, p. 1.

348 ERM Power, submission to directions paper, p. 6.

349 Aurora Energy, submission to directions paper, p. 3.

is, changes to the regulatory framework must be made in the long term interests of consumers. Therefore, the Commission has developed an assessment framework by which to consider potential ways that wholesale demand response could be facilitated.

The Commission has considered the following principles:

- **Promoting competition**: Competition provides incentives for market participants to provide services that consumers value, given the price. It is also the mechanism by which the benefits of efficient levels of demand response accrue to consumers.
- **Resilience of the framework**: Regulatory arrangements must be flexible to changing market conditions. They should not be implemented to address issues specific to a particular time period or jurisdiction, or the prevailing technology of the day. This encompasses both technology neutrality but also the ability of the framework to adapt, regardless of what the future brings.
- **Not distorting efficient market outcomes**: Changes to the regulatory framework should not detract from the ability of the NEM to provide for the least cost combination of supply-side and demand-side options at any point in time. A distortionary change to regulatory frameworks would detract from the allocative and dynamic efficiency of the current market frameworks.
- **Transparency**: Providing greater amounts of information to market participants will improve their ability to make efficient decisions in both operational and investment time frames on both the supply and demand side of the market.
- **Appropriate risk allocation**: Any changes to regulatory framework to facilitate wholesale demand response should be cognisant of the risks introduced and the party(ies) that bears the costs associated with this risk. A risk can be considered to be allocated to the best party when:
  - there is an incentive to manage that risk because the party will gain or lose in the event of the risk materialising
  - the party managing the risk has the most information about it and how it can be mitigated
  - there is the ability for that party to improve its risk management over time.
- **Administrative costs**: Where costs are imposed in implementation and cannot be mitigated through market mechanisms, these costs should be minimised relative to the benefits of the regulatory changes.

These principles are consistent with the ACCC's Retail Electricity Pricing Inquiry final report which recommended that a mechanism for third parties to offer demand response directly into the wholesale market should:[350]

- promote competition through allowing the widest range of businesses to directly offer demand response services

350 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

- not allow retailers to limit the ability of their customers to engage a third party demand response provider (to the extent it is not inconsistent with the retail contract)
- ensure load and generation response are valued appropriately based on the benefit they provide to the wholesale market
- limit technical requirements placed on the customer that may inhibit take up or scope of these services (for example, requirements for multiple meters at the customer site) .

The AEMC looks forward to incorporating the ACCC's principles in any rule changes that it receives following the publication of this report.

A.4 Recommendations to facilitate demand response in the wholesale market

As noted above, there is a lack of transparency about how much wholesale demand response is currently being utilised in the NEM and so it is difficult to draw firm conclusions on how much demand response is occurring, nor whether the level of demand response is efficient.

What is undisputed is that consumers want more opportunities to participate in demand response. Commercial and industrial consumers are generally better equipped to provide wholesale demand response, and typically have greater opportunities to participate in the wholesale market. On the other hand, residential consumers haven't had the same opportunities or capabilities to provide demand response. However, this is likely to not remain the case with new technological developments and business models providing consumers with increased opportunities to participate in the wholesale market.

In many instances, wholesale demand response can more efficiently contribute to reliability than building new generation. This is particularly true when a tight supply-demand balance is only forecast to occur for a short period of time. An active demand-side, characterised by the presence of wholesale demand response, promotes efficient consumption of electricity in the wholesale market. Where load can effectively respond to prices, it can "choose" its level of consumption based on its willingness to pay for consuming electricity compared to the cost of that electricity. In a tight supply-demand balance, high prices would encourage an active demand-side to reduce consumption and maintain the reliability of the power system.

To facilitate wholesale demand response consumers need to be provided with more opportunities to become active participants in the wholesale market and respond to price changes. Demand response provides consumers with the opportunity to reduce costs by lowering consumption during high priced periods and shifting consumption to low priced periods. So, when we seek to facilitate wholesale demand response, it is not about having more demand turn off during a high price. It's about having more consumers enabled to make informed decisions regarding levels of consumption and with regard to the wholesale price.

The Commission therefore considers that the barriers to entry for providing demand response in the NEM should be lowered so *more* consumers have *more* opportunities to offer wholesale demand response.

A key challenge at the moment is that the interaction between a consumer and the wholesale market is directly managed by a retailer. If that retailer doesn't offer demand response products, or provide a direct signal of the wholesale price consumers have no incentive to change their consumption since they have no signals to do so.

Further, in order to respond to wholesale price signals, consumers need to be able to have a reasonable level of certainty about what the real time price will be (or hedge against changes to those expectations). Forecasts can assist with this by providing an indication of expected outcomes. However, approaching real time, forecasts will change as they reflect updated information about the nature of the system, and about revised participant decisions and intentions. The value of price certainty for demand response was noted in submissions from large energy users including CSR Limited and Bluescope Steel.

Financial instruments can be used to provide participants with greater price certainty. On the supply-side, generators can manage real-time price uncertainty by using financial instruments that have the effect of locking in a price ahead of real time. Similarly, retailers use financial contracts to manage the volatility of the wholesale price. However, smaller consumers may find it difficult to enter into these contracts on an enduring basis.

In considering these we have also sought to balance this against the risks that this could impose on consumers. The Commission is conscious of affordability concerns in the market at the moment and would be wary of recommending anything that would impose undue costs on consumers.

We think that there are a number of ways in which wholesale demand response can be facilitated. It is important that consumers have choices in how they generate their own electricity, better manage their consumption and engage in demand response. Therefore, we need to provide a range of options for how wholesale demand response can be facilitated - allowing parties to innovate, and consumers to exercise choice in how and when they provide wholesale demand response. This also promotes flexibility and resilience, irrespective of what the future may bring. The regulatory framework will be able to evolve in line with consumer preferences.

What is particularly important is that parties other than the existing retailers can be provided with opportunities to provide demand response offerings to consumers. As recognised in our *Retail Competition Review*, retailers have been slow to innovate on tariff, pricing and products, consumers have also taken matters into their own hands, with increased investment in distributed energy resources, such as solar PV systems and batteries. This applies equally to demand response as well. Allowing new parties to sell wholesale demand response would increase the competition for these services and provide consumers with greater value.

Our recommendations therefore seek to facilitate demand response in the wholesale market, by removing potential restrictions to providing wholesale demand response and provide a range of additional tools to help the demand side attain more price certainty ahead of real time, while preserving the market-based arrangements in the NEM underpinned by flexible and resilient regulatory frameworks. These recommendations complement each other to provide avenues for facilitating demand response in the wholesale market.

There has been significant interest from multiple stakeholders - representing a range of industry participants - who have noted that they intend to submit a rule change request to the Commission to implement our a way for demand response aggregators to be treated on equal footing with generation i.e. implement a demand response mechanism. The Commission welcomes this - integrating demand response into the wholesale market is a critical component of facilitating the energy sector transition and so we do not consider there should be any delays in progressing this issue. If the Commission has not received a rule change request from one of these stakeholders by the end of August 2018, then it will draft a rule change request that the Energy Security Board can submit.

In addition, AEMO and ARENA will be trialling in-market demand response. The objective of this trial is to demonstrate the potential to increase wholesale market competition by improving access of demand-side resources to spot market pricing. Under the trial, demand response would be provided to the spot market by the customer / aggregator which displaces the energy which would otherwise have been provided by the marginal generator. As an in-market trial, the majority of the revenue would be earned in the spot market, paid for by retailers and dispersed to demand response providers through the market settlement system.

In order to facilitate increased demand response in the wholesale market, and in response to Finkel Panel recommendation 6.7 we consider that:

- A voluntary, contracts-based short-term forward market be implemented that would allow participant-to-participant trading of financial contracts closer to real time. This will provide the demand side with more opportunities to lock in price certainty, making it easier for large demand side consumers to engage in the wholesale market and demand respond (i.e. reduce consumption) in response to expected wholesale prices. AEMO should undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market.
- Demand response aggregators and providers should be able to be recognised on equal footing with generators in the wholesale market and so offer wholesale demand response transparently into the market. The Commission understands, through their submission to this Review, that TEC and PIAC will submit a rule change request to the AEMC to implement a wholesale demand response mechanism by end of August 2018. If these stakeholders have not submitted a rule change request by this time then the Commission will draft the rule change request for the Energy Security Board to submit.
- Consumers should be allowed to engage multiple retailers / aggregators at the same connection point (multiple trading relationships). This will promote competition between retailers, supporting new business models for demand response and providing consumers with greater opportunities to engage in wholesale demand response with parties other than their incumbent retailer. Subject to the outcomes of relevant trials, AEMO should

develop a rule change request to submit to the Commission to implement multiple trading relationships.

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We discuss these recommendations in turn below. The structure of each of the following sections replicates the typical structure of a rule change request to help any participants who are considering submitting a rule change to us on these issues.

While we think that treating demand response providers on equal footing with generators will have benefits, we need to better understand the extent of the associated direct and indirect costs. Therefore, we consider that there would be benefits from having trials to test and inform policy decisions. As noted above, these will be undertaken by AEMO and ARENA through in-market demand response trials. These trials would allow the market bodies, interested stakeholders and market participants to trial these new services being provided in the wholesale market. It would also provide an opportunity to consider how consumers respond under these new frameworks, observe these new models may foster and further provide learnings to the Commission about how these changes might promote the long-term interests of consumers.

It is also important to that demand response products are significant for the proposed National Energy Guarantee. As noted in the technical working group paper on demand response published alongside the National Energy Guarantee draft detailed design consultation paper:[351]

> Demand response products designed to meet any future arrangements the AEMC puts in place are likely to be automatically eligible for the reliability requirement and the AEMC will be able to amend the rules to align with any future scheme. However, the treatment of demand response under the Guarantee is designed to ensure that the eligibility of demand response under the reliability requirement is not dependent on the implementation of new arrangements.

A.5 Short-term forward market

The Commission considers that there would be benefit in introducing a voluntary, contracts-based short term forward market into the NEM to facilitate trading of hedging products between participants in the short-term. This section discusses this further.

A.5.1 Overview

The interim report to this review discussed ahead markets that are designed to facilitate greater levels of trading between market participants. Such ahead markets were termed European-style ahead markets, as they are typically observed in European electricity markets but may be otherwise known as short-term forward markets. We use this term ("short-term forward markets") throughout the remainder of this section.

351 Energy Security Board, National Energy Guarantee, *Technical working paper - demand response*, p. 3, June 2018.

Short-term forward markets assist participants with concentrating trading liquidity at a certain point in time; as well as allowing market participants to fine tune previously traded positions ahead of real time and/or to hedge against volatility in the real time market. This aids the ability of market participants to enter into hedging products.

The Commission's preliminary view as expressed in the interim report was that these markets are much closer to the current market arrangements, where market participants enter into and supply financial contracts, than a US-style ahead market[352] and that there were few, if any, barriers to the establishment of such a market in the NEM.

The interim report found that since such a market was not markedly different from the current arrangements there would be few direct reliability benefits associated with such a trading tool. The indirect reliability benefits could be derived from improved transparency and incentives to provide more accurate forecasts through their bids in the ahead market. There would also be limited benefits to the system operator in operational timescales since information flows typically flowed between market participants in this model.

However, there are a number of other benefits associated with markets that are designed to facilitate trading over shorter time horizons - which were recognised by AEMO in their submission to our directions paper. A liquid short term forward market may aid price discovery and give participants greater certainty of price signals. Such a market may facilitate greater demand-side participation in the wholesale electricity market. This is because they may give demand response providers greater ability to contract in advance at a certain price which would give them sufficient notice to deploy their demand responsive resources.

A.5.2 Nature of the issue

Under the current arrangements, a number of stakeholders have highlighted uncertainty regarding future prices as a barrier to demand response.

For example, a consumer might observe a forecast high price and commit to undertaking demand response. However, in real time, if the forecast high price does not eventuate the consumer would not see the benefit of undertaking demand response. We recognise that these challenges are not unique to the demand side - generators in the NEM make the same decisions based upon expectations of future prices.

Financial instruments can be used to provide participants with greater price certainty. On the supply-side, generators can manage real-time price uncertainty by using financial instruments that have the effect of locking in a price ahead of real time. Similarly, retailers use financial contracts to manage the volatility of the wholesale price.

However, smaller consumers may find it difficult to enter into these contracts on an enduring basis. Smaller consumers may be able to more actively participate and manage price uncertainty in a shorter timeframe where they have a better understanding of expected production and maintenance schedules.

352 For more information, see Appendix DAM.

A.5.3 How this recommendation would address the issue

A short-term forward market would provide the demand side with greater opportunities to lock in a price for reducing consumption and demand response. Indeed, this market would provide all market participants with increased price certainty and the ability to lock in a price in advance of dispatch.

Allowing consumers greater opportunities to lock in a price for reducing consumption ahead of time could provide price certainty. The lack of notice and time it takes to respond to price spikes are considered as barriers to wholesale demand response. Shorter-term trading through a facilitated market may therefore enable increased wholesale demand response in the NEM. Price certainty has been raised by some stakeholders as a challenge for demand response, particularly when there is a significant lead time on changing the demand.[353] This is demonstrated in Box 7.

BOX 7: A SHORT-TERM FORWARD MARKET FACILITATING DEMAND RESPONSE

Example 1

An energy consumer is participating in both a voluntary, contracts-based short-term forward market and the real-time wholesale electricity market.

The consumer is able to change their level of consumption. However, the consumer will incur costs of $5,000 to undertake demand response and they have to commit to this demand response ahead of real time.

Due to changing operating conditions, the consumer will now have some unhedged load in the short term. The consumer buys 100 MWh for the next day in the short term forward market at a price of $50/MWh. The counterparty to this short term forward contract could be a generator looking to lock in a price for its generation.

The next day, a contingency occurs and the wholesale price for electricity rises to $500/MWh. The consumer decides not to consume anything, and is paid by the counter party for the difference between the short-term forward market price and the real time price. Therefore, the consumer earns:

- (100 MWh * ($500 - $50)/MWh) = $45,000.

The consumer also incurs the cost of demand response:

- -$5,000.

The net position for the consumer is:

- $40,000.

Example 2

This time the energy consumer has also entered into a long-term swap with a generator for

353 While an ahead market can provide more opportunities for price certainty for demand side participation in the wholesale market, it would not necessarily facilitate demand response from participants who are not the FRMP.

100 MWh per day, at $50/MWh.

There is an expectation that prices will be high tomorrow. The consumer sells 50 MWh for the next day in the short-term forward market at $500/MWh. The counterparty to this contract could include:

- a gas generator unable to secure gas supply to defend a cap position
- a market customer that wants to hedge any unhedged load
- a generator concerned about possibly being affected by an outage the next day.

Outcome 1: If the next day, the wholesale price is $300/MWh. The consumer consumes 50 MWh.

- The consumer buys 50 MWh at the real time price: cost of 50 MWh * $300/MWh = $15,000.
- The consumer is compensated for their swap position: earn 100 MWh * ($300 - $50)/MWh = $25,000.
- The consumer is also compensated for their short term forward market position: *earn* 50 MWh * ($500 - $300)/MWh = $10,000.
- The consumer incurs the costs of demand response: -$5,000.
- The net position of the consumer is a *gain* of $15,000.

Outcome 2: The next day, the wholesale price is $1,000/MWh. The consumer consumes 50 MWh.

- The consumer buys 50 MWh at the real time price: *pays* 50 MWh * $1,000/MWh = $50,000.
- The consumer is compensated for their swap position: *earn* 100 MWh * ($1000 - $50)/MWh = $95,000.
- The consumer compensates the counter party for their short-term forward market position: *pays* 50 MWh * ($1,000 - $500)/MWh = $25,000.
- The consumer incurs the costs of demand response: -$5,000.
- The net position of the consumer is a *gain* of $15,000.

This example demonstrates how a short-term forward market allows a consumer to lock in price certainty to sell demand response. Regardless of what the real-time price is, by using the short term forward market the consumer locked in a price for the quantity of demand response. This would allow a consumer to make a decision to undertake demand response ahead of real time, which includes being able incur any upfront costs and be certain that these costs will be recovered.

Note: The second example involves a consumer hedging their consumption and actively trading contracts to achieve price certainty for demand response. If the consumer is doing so directly, they would likely need a license to trade these products. This would impose additional trading risks and regulatory burdens on the consumer. An alternative is that a third party with the appropriate licensing could trade these product on behalf of the consumer.

Potential design of a short-term forward market

There are a number of design choices that would need to be made designing a voluntary contracts-based short term forward market. One possible model of this market is that it could be run by AEMO and have the following design features:

- a voluntary exchange, similar to the Gas supply hubs (GSH)
- anonymous bids and offers matched continuously throughout the day based on price and volume
- daily contracts traded on a rolling basis for the following day and up to seven days in advance
- flat contracts for a 24 hour period as well as blocks across the day to manage peak, off-peak and shoulder periods.
- separate contracts linked to each regional reference price in $/MWh.

There are a number of advantages associated with this model.

Implementation costs could be minimised by using the same trading interface as the GSH (Trayport). AEMO indicated that the final implementation costs of such a model are unlikely to be prohibitive and the market could commence within 18 months of the detailed design process commencing.

In addition to minimising implementation costs there is an additional benefit in using the same trading interface - this would reduce costs for those already familiar with the platform. Using the same trading interface in both markets may facilitate integration between gas and electricity markets. This is because gas generators could sell short-term electricity contracts when prices are high and then immediately source gas on the GSH to meet this contractual obligation. The result may be that gas generators may find it easier to respond to price signals at short notice.

The Commission notes that this is one such design of a short-term forward market, but there may be others. Therefore, the Commission considers that a rule change should be submitted to the Commission to implement a short-term forward market. This will allow further consideration of the legal issues highlighted below as well as policy issues, such as the impact of market power issues on the operation of a short-term forward market, and the interaction with the gas market.

A.5.4 Benefits and costs

The Commission considers that there would likely be benefits in pursuing a short-term forward market in the NEM.

A market that facilitates shorter-term financial trading of hedging products in the NEM would serve a number of useful purposes that could lead to increased demand side participation in the wholesale market. These include:

- providing market participants with greater confidence in the price signal, by enabling them to lock in a price for consumption ahead of time which would provide price certainty
- potential for greater demand-side participation due to increased price certainty
- providing greater opportunities for participants to manage wholesale price risk

- concentrating liquidity in hedging products at a certain point in time closer to dispatch
- increased flexibility by allowing market participants to fine tune previous traded positions
- providing more information to participants regarding the state of the market ahead of real-time
- may allow for greater participation of gas, wind and solar generators:
    - allows greater certainty for gas generators to source short-term gas on the gas supply hubs - this is discussed in more detail below
    - more closely aligns with the time frames over which a wind or solar generator could forecast with a greater degree of certainty.

While there are no regulatory barriers to the establishment of such a market in the NEM, such a market has not developed. The lack of such a market developing could indicate a lack of appetite from market participants for such a short-term forward market. However, given we have heard from participants that there would likely be benefits in a short-term forward market, it may more possible that a market failure exists. For example, the relatively high transaction costs of negotiating over-the-counter (OTC) contracts and credit arrangements for contracts of a short tenure could preclude the development of short-term OTC products. Similarly, the additional prudential obligations of trading ASX futures and OTC contracts may reduce the attractiveness for some parties looking to trade short term products.

Forecasting affects the ability for demand response to be used in conjunction with a short term forward market since forecasts of real time prices will influence the prices observed in a short term forward market. This review has made a number of recommendations to improve the transparency of forecasting processes in the NEM, which are discussed in chapter 3.

A.5.5 Legal considerations

A decision on the final model will be influenced by a range of legal issues that require further consideration. These issues may also impact on potential benefits and timing. Some of these issues are discussed below.

- A preliminary issue is whether the short-term forward market should be treated as part of the 'wholesale exchange' (as defined in the National Electricity Law) that forms part of the national electricity market (as defined in that Law) or whether it should have a separate legal identity under the Law. This may depend both on how the National Electricity Law applies to the preferred design of the market and the other legal issues identified below.
- Options for credit risk management and settlement include stand-alone arrangements and integration with the NEM prudentials and settlement systems. If stand-alone arrangements are used, measures to mitigate credit risk similar to those applicable to the GSH may be desirable.[354] For the integrated model, potential impacts on the NEM or NEM participants arising out of integration will need to be considered, including impacts on credit risk and credit risk management, GST treatment of NEM transactions and the

354 In the case of the GSH, this includes a declaration under the Payment Systems and Netting Act 1998 (Cth). Payment Systems and Netting Regulations 2001, regulation 3A.

continuing application of other exemptions from which the NEM or NEM participants benefit.[355]

- Depending on the market design, operation of the short-term forward market and market participation may require financial services licences under Chapter 7 of the Corporations Act or exemptions from the requirement to hold one or more of those licences. Exemptions from the obligation to hold financial services licences have been granted in the relation to the GSH and in relation to reallocation in the NEM.[356] The availability of similar exemptions in relation to a short-term forward market will likely need to be considered as part of the design phase.
- The potential for market manipulation in relation to the short-term forward market will be considered in the design phase. To the extent regulation under the Corporations Act or the existing Rules is not otherwise applicable, the design will need to include measures to facilitate identification and regulation of the conduct being targeted.

A.5.6 Next steps

Given the benefits described above, the Commission considers a voluntary, contracts-based short-term forward market should be introduced into the NEM. The Commission recommends that AEMO undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market which would allow participant-to-participant trading of hedging products closer to real time to provide the demand side with more opportunities to lock in price certainty.

A.6 Multiple service providers at a connection point

The Commission recommends changes to regulatory framework to better enable consumers to access multiple service providers. It is envisaged that this would provide opportunities for consumers to access value from different parts of the supply chain, as well as supporting the integration of increasing amounts of distributed energy resources.

A.6.1 Overview

Under the current arrangements, a consumer is only able to have a single FRMP at a connection point. This means that a consumer is only able to buy electricity from a single retailer at each connection point. This has the effect of bundling retail energy supply, wholesale demand response and energy exports from distributed energy resources such as solar PV. Allowing consumers to access multiple service providers at a connection point would help with unbundling the above services.

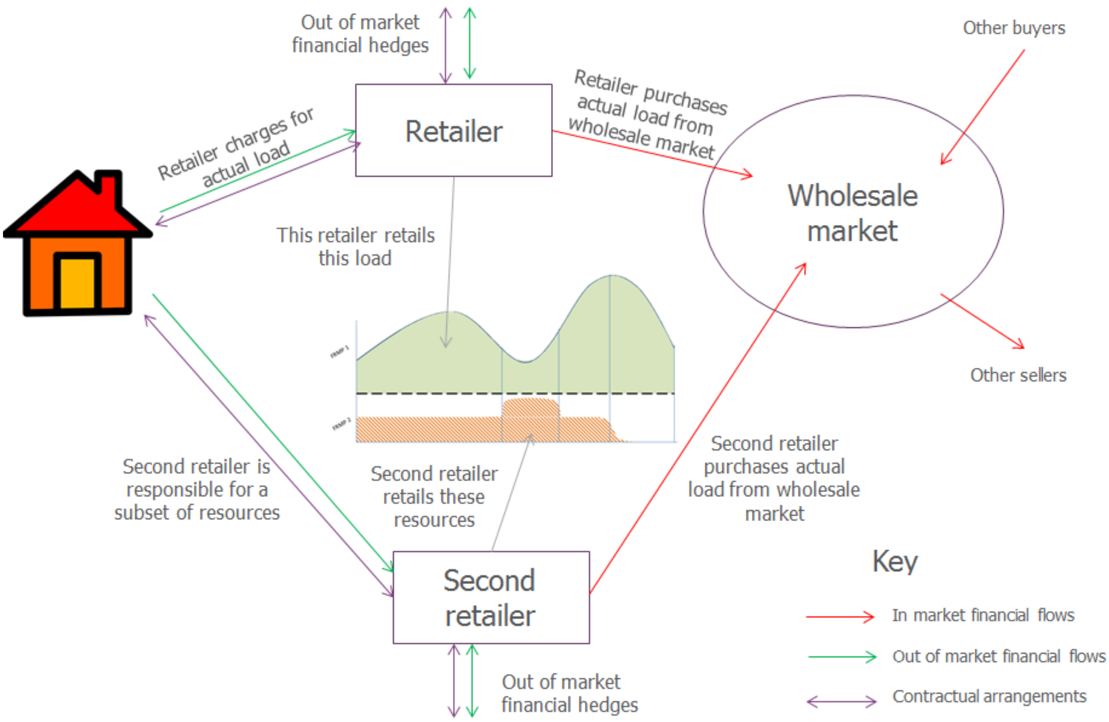
Third parties would be allowed to be a FRMP behind a connection point for a subset of the resources (including loads and distributed energy resources) without becoming the FRMP for

355 Such as an exemption under chapter 22 of the Anti-Money Laundering and Counter-Terrorism Financing Rules Instrument 2007 (No. 1), and the CS facility licence exemption granted to AEMO in respect of swap and offset reallocations (Notice under section 820C of the *Corporations Act* 2001 (Cth), 23 February 2016).

356 Corporations Regulation 7.6.01(1)(z); Corporations Regulation 7.10.03; Corporations Regulation 9.12.05.

all of the load behind that connection point. An example of such an arrangement is demonstrated in Figure A.2.

Figure A.2: Proposed arrangements



The Commission considers this change would provide consumers with greater opportunities to interact with the wholesale market and engage with a number of different service providers. It would also facilitate the integration of new dynamic and controllable resources in the wholesale market and provide increased opportunities for consumers to engage in demand response.

This would enable other sources of value to be accessed by consumers. Allowing consumers to access multiple service providers at the same connection point would support small generation aggregators and may allow regulatory frameworks to better accommodate orchestrated distributed energy resources (often referred to as a virtual power plant or VPP) participating in the wholesale market. For example, where solar PV and/or a battery is co-located with consumer load behind a connection point, participation in the wholesale market can only occur through a single market participant (typically a retailer). Under this proposal, a third party could aggregate the output of multiple consumer batteries for participation in the wholesale market.

It would also allow the regulatory framework to enable nascent developments such as the growing interest in electric vehicles. This recommendation could facilitate arrangements where a consumer is able to establish a separate retail relationship for their electric vehicle and maintaining their existing retail relationship. Implementing this arrangement would also allow for innovate approaches to retailing electric vehicle load to emerge.

The Commission notes that the Electricity Authority in New Zealand is also currently contemplating changes to its regulatory frameworks to allow consumers to access multiple FRMPs, and is in discussions with the Electricity Authority to see what lessons can be learned.[357]

A.6.2 Nature of the issue

Under current arrangements, a consumer is only able to engage with a single participant at a connection point in respect of any interactions with the wholesale market.[358]

There are a number of situations in which a consumer may wish to engage with separate service providers at the same connection point:

- domestic consumers could separate electricity charging for uncontrollable loads and controllable loads (such as air conditioning, hot water, pool pumps and electric vehicles) between retailers
- a commercial or industrial customer may elect to have a spot price pass-through contract with a new retailer for a controllable sub-load
- a consumer may be a party to a virtual power plant arrangement and wish to have their residential storage and solar PV separately metered to enable participation with the virtual power plant.

Consumers are able to achieve the above by establishing a separate connection point or through the existing embedded networks framework (discussed further below). This was highlighted in submissions to the directions paper. For example, EnerNOC noted that a participant with a retail license could create an embedded network with a new child National Metering Identifier (NMI) and act as the FRMP for the child NMI.[359]

However, there are challenges associated with these options. To establish a second connection point:

- a consumer may be required to invest in rewiring a premises to establish the second connection point
- a consumer would need to pay the costs associated with establishing a second connection point
- a consumer would need to pay two sets of networks tariffs.

These costs may be unnecessary or duplicative.

Equally, the embedded networks framework does not seem appropriate for all circumstances where a consumer might seek to engage multiple service providers - to be used in the above

357 The Electricity Authority is currently consulting on whether allowing consumers to access multiple FRMPs at a connection point would result in more efficient outcomes. The consultation can be accessed on the Electricity Authority's website: https://www.ea.govt.nz/

358 However, a consumer is able to engage with third parties to provide FCAS and to provide network services.

359 EnerNOC, submission to directions paper, pp. 11-12.

scenarios seems to be using that framework as a workaround. These frameworks were set up to allow for consumer protections and retail contestability for consumers connected within an embedded network, not to facilitate multiple trading relationships. These are different objectives to the intention of this proposal. For a single small to medium sized consumer behind a single connection point, it would be impractical to incur the costs of meeting these requirements which suggests that an embedded network would not be a practical solution for a customer seeking to engage with multiple FRMPs at a premises.

Consequently, the current regulatory framework does not facilitate consumers easily engaging with multiple FRMPs at the same connection point. While it may not be impossible, the existing avenues for doing so may present barriers that make them not appropriate for all possible applications. Providing a low-cost opportunity for consumers to engage multiple FRMPs would provide consumers with more opportunities to access a range of service providers. This would consequently promote retail competition and innovation.

A.6.3 How this recommendation would address the issue

The proposed solution would allow a consumer to engage multiple FRMPs at the same connection point.

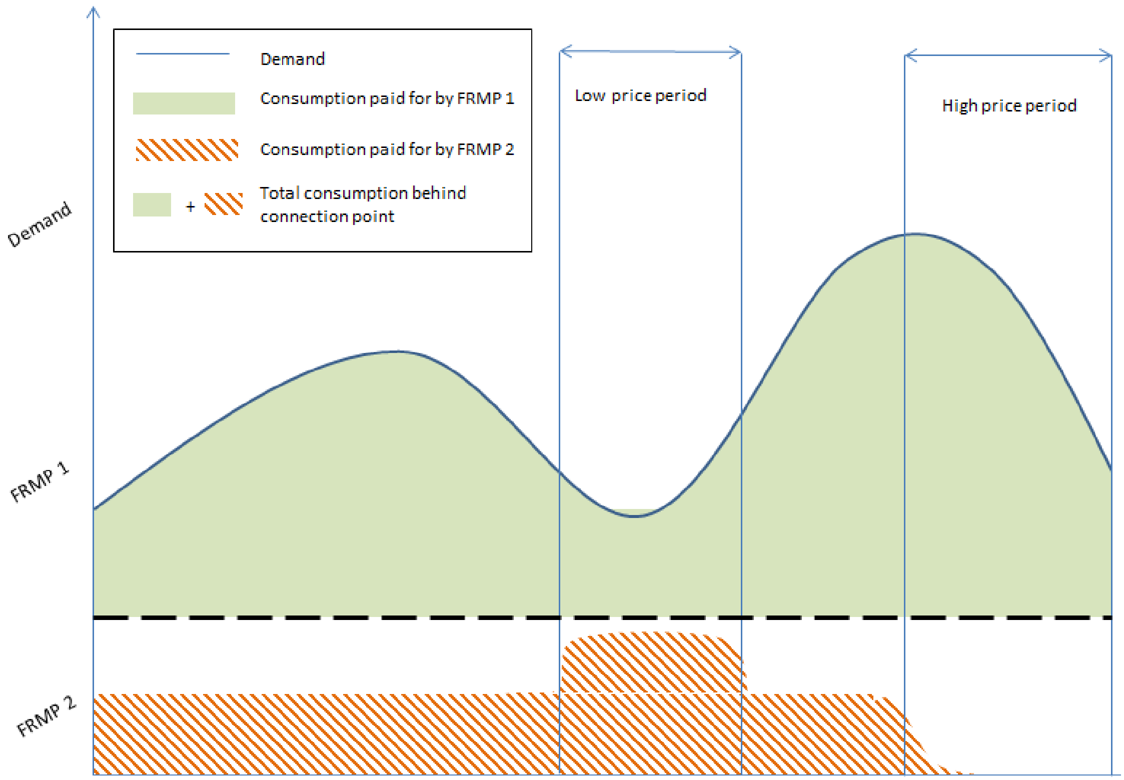
This would transfer spot market responsibility for some of the resources behind a connection point from the existing FRMP to a new FRMP. This would allow a consumer to elect to have a standard retail contract with one retailer, while third parties would be able to disaggregate demand responsive load (and other resources e.g. batteries and solar PV) to be used in the wholesale market. The consumers would be able to change retailer for the non-responsive component of their consumption without impacting on the new FRMP accessing the controllable demand response. Since the new party would only be responsible for a subset of the load, the costs (e.g. prudential requirements) associated with this role should be less onerous than becoming a retailer for the whole of the load.

Figure A.3 demonstrates how a load might be separated into a two components: a responsive, controllable load and a non-controllable load.

In this example, the initial FRMP now retails a smaller component of the customers' load. Because some of the dynamic load is now being separately retailed, the initial FRMP may be able to better predict the load shape and consequently better anticipate and manage the variability of its retail portfolio.

The second FRMP retails the sub-set of controllable load. If it installs controls, it is able to shift consumption from high priced periods to low priced periods to reduce wholesale price exposure. This would allow the second FRMP to retail the load at a lower cost which would reduce costs faced by the consumer. Alternatively, the second FRMP could provide the consumer with a spot price pass-through arrangement and the consumer would then face the incentive to manage its load in response to signals from the wholesale market.

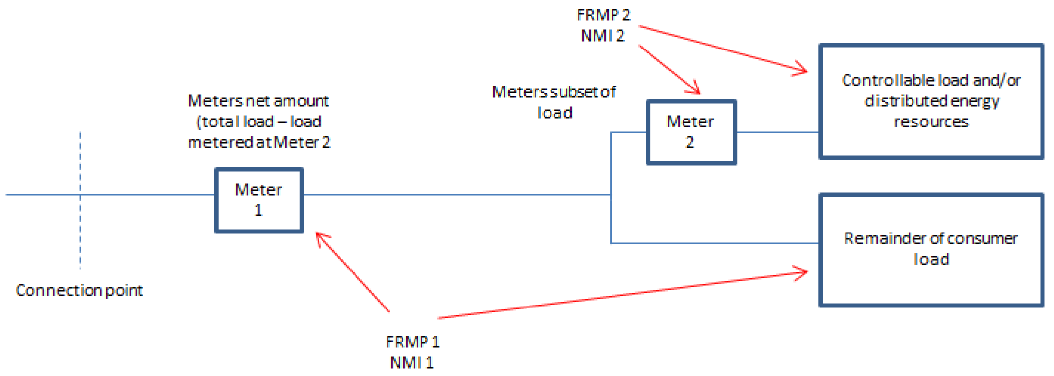
Figure A.3: Transferring responsibility to third party



Under this option, the rules would not specify the metering arrangements that would be introduced (beyond the existing requirements for accurate metering of energy use for billing purposes). This is because different metering arrangements would likely facilitate consumers accessing different combinations of service providers. For example:

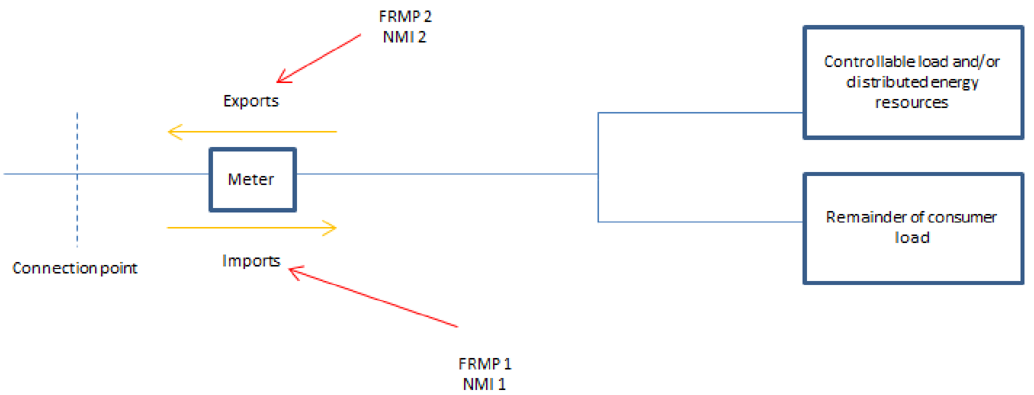
- For a consumer engaging multiple retailers for different loads, subtractive metering arrangements (shown in Figure A.4) might be most appropriate. This is where a single settlement meter is retained but some loads are sub-metered and subtracted from the net load at the settlement meter.

Figure A.4: Subtractive metering



- For a consumer with on-site generation (e.g. rooftop solar panels), engaging a retailer and a small generation aggregator using import/export metering arrangements (shown in Figure A.5) may provide the consumer with greatest value. This is where a single settlement meter is retained with an element for import and an element for export. The imports of energy would be attributed to one FRMP and the exports would be attributed to another FRMP. This would allow the consumers to get the benefits of offsetting retail costs with any distributed energy resources and also being able to sell energy exports to through a third party. It is unclear whether this would have direct benefits for demand response providers; however, it may facilitate greater integration of distributed energy resources and virtual power plants.

Figure A.5: Import/export metering



A range of changes to metering and settlement rules and procedures would be required, in addition to some potential changes to customer protection arrangements under the National Energy Retail Law and Rules, as discussed below, for example:

- There would be a need to accommodate two or more NMIs at a connection point. This is possible under the current NER as NMIs are linked to metering installations as opposed to a connection point. A consumer would have two (or more) NMIs in MSATS which would be allocated to the respective FRMPs. Under the embedded networks framework, AEMO and distributors already need to account for multiple NMIs (a parent NMI and child NMIs) at a connection point, so the required systems changes may not be extensive.
- There may need to be qualifying criteria for a consumer to be able to engage multiple FRMPs. A number of the challenges associated with this recommendation relate to maintaining consumer protections, in particular those that apply to small customers. These challenges could in part alleviated if some qualifications were required, such as:
  - only allowing large customers to engage multiple FRMPs
  - requiring each FRMP to be able to disconnect and reconnect its individual load, independently of the other FRMP's portion of the customer's load.
- There would need to be further consideration of how network tariffs should be apportioned between the FRMPs.

Differences from previous *Multiple trading relationships* rule change request

The Commission has previously considered a similar solution under the *Multiple trading relationships* rule change request.[360] The focus of that rule change request centred on the integration of electric vehicles and providing consumers with the ability to elect to have a separate retailer for an electric vehicle. The Commission acknowledged in the final determination for that rule change request that there would be other potential benefits of introducing multiple trading relationships,[361] and the Commission now considers that these benefits have become increasingly prominent.

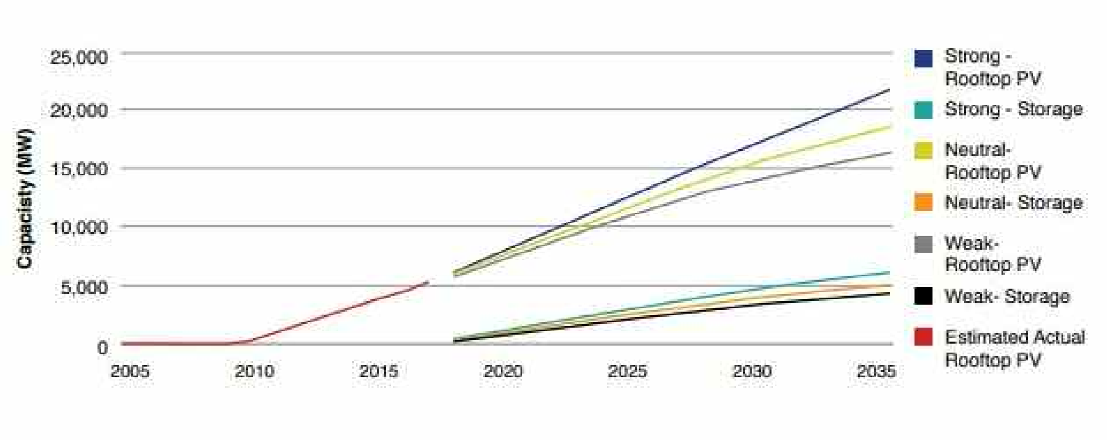
It is worth noting that a number of aspects of the energy market have changed since we made a final determination for that rule change request, which we think translates to more benefits being realised from this option. This includes:

- The increasing uptake of distributed energy resources, including solar PV, batteries, electric vehicles and dynamic controllable loads. A formerly passive demand side is becoming increasingly engaged through the uptake of distributed energy resources which are greatly expanding the choices that consumers have to manage their energy needs at the household/business level. Figure A.6 show the growing, and projected growth, of these resources in the NEM. In aggregate, they have the potential to provide value to consumers and NEM participants through the provision of wholesale services (such as FCAS) or network services (such as network congestion management).

360 See: https://www.aemc.gov.au/rule-changes/multiple-trading-relationships

361 AEMC, *Mutliple trading relationships*, final determination, p. 26, February 2016.

Figure A.6: Uptake of solar PV and storage



Source: AEMO/Energy Networks Australia, *Open Energy Networks*, consultation paper, p. 10, June 2018.
Note: This is a projection of installed capacity of rooftop PV and distributed energy storage in the NEM.

- The growing number of virtual power plants where distributed energy resources are being orchestrated to provide services on a wholesale level. Examples of current virtual power plants include the Simply Energy virtual power plant, the AGL virtual power plant and the South Australian Power Networks virtual power plant. The growing number of virtual power plants may lead to higher rates of uptake of multiple trading relationships than was considered in the previous rule change request.
- Configurations of meters that would reduce the cost and complexity of accessing multiple FRMPs at a connection point. In the *Multiple trading relationships* rule change request, the Commission considered a limited set of metering arrangements. The model recommended now may facilitate a consumer accessing multiple service providers at a lower cost than the model that was considered in the *Multiple trading relationships* rule change process by considering different metering arrangements, including single meter models.
- Renewed stakeholder support from small generation aggregators and AEMO. EPC Technologies (a small generation aggregator) submitted that empowering consumers to be able to engage with multiple service providers would support innovation and allow consumers greater access to the wholesale market.[362] AEMO also suggested that, when considering barriers to distributed energy resources participating in FCAS, thought should also be given to how a consumer might be able to access multiple parties at a connection point.[363]

A.6.4 Benefits and costs

Introducing multiple trading relationships could have a number of benefits including:

362 EPC Technologies, submission to directions paper, p. 2.
363 AEMO, submission to *Frequency control frameworks review - draft report*, p. 10.

- Providing consumers with more choice to use energy when it is of value to them, and reducing consumption where the cost exceeds this value. Over time, this framework would facilitate the use of new technologies that allow for the least cost use of resources to meet consumer needs.
- Increasing the range of services available to be provided to, and by, consumers.
- Promoting greater retail competition and innovation. By creating opportunities for more targeted and bespoke retail business models, this change could facilitate the development of retail models that are better able to cater to the value individual consumers can provide. For example, retail offers that specifically cater to electric vehicles.

This would have the effect of unlocking value that can be created with demand-side resources. Demand responsive load would be able to be aggregated and controlled to create value for consumers in wholesale markets, in providing ancillary services such as FCAS and in assisting in reducing network congestion.

It could also provide consumers with greater opportunities to take spot price exposure for a sub section of their load. This could enable these consumers to undertake wholesale demand response and retain a retail contract for their remaining consumption.

There are broader benefits that may be facilitated by allowing multiple parties to interact with a consumer behind the same connection point. These benefits, shown in Figure A.7 below, include more opportunities for demand side flexibility, distributed energy resources and peer to peer trading.

Figure A.7: Possible benefits of this option

Source: AEMC, *Multiple trading relationships - consultation paper*, July 2015, p. 19.

The Commission also recognises that there may be some costs associated with this recommendation, these include changes to costs imposed on retailers and distributors in relation to IT systems and processes based around a one-to-one relationship between connection point, FRMP, NMI and metering installation. At the time of the *Multiple trading relationships* rule change request, distributors identified that breaking the one-to-one link between connection point, FRMP, NMI and metering installation would require a number of systems to be simultaneously overhauled due to the integrated nature of the systems.[364]

We would need to consider these costs in light of the current arrangements.

A.6.5 Legal considerations

Some of the legal issues raised through the *Multiple trading relationships* rule change process remain relevant to further consideration of this recommendation.

364 AEMC, *Multiple trading relationships*, final determination, p. 40, February 2016.

The model considered by the Commission in the *Multiple trading relationships* rule change provided for multiple settlement points at a single connection point under the NER and changes to metering rules. In the final determination, the Commission noted that implementation of multiple trading relationships would require a review of the NER and the NERR to determine whether the obligations in the NERR remained appropriate following the introduction of changes to the NER to accommodate multiple trading relationships.[365] In relation to the NERR, the model considered in the previous rule change would have continued to classify customers by reference to the premises as a whole.[366] The Commission acknowledged that other changes to the NERR may be required to recognise a customer may have multiple FRMPs at a site and to preserve the operation of customer protections. It identified the need for rules to deal with the allocation of network charges among the settlement points at a site.

To allow consumers to access multiple FRMPs at a connection point under the current recommendation, similar changes to the NER, NERR and related instruments to those previously explored would need to be considered. The review of the NER and NERR that was flagged in the previous rule change request also would likely be needed to determine whether the obligations in the NERR remained appropriate following the introduction of multiple trading relationships, even if aspects of the design differ from those considered in the *Multiple trading relationships* rule change.

The Commission also considers that the implementation of multiple trading relationships at one connection point may require changes to the NERL to avoid uncertainty regarding the application of the NERL, and to maintain customer protections.[367] This may depend on whether multiple trading relationships are permitted for all customer categories (as discussed below).

The NERL may need to be amended for the following reasons:

- There is an assumption underlying the NERL that each premises has one distributor and one retailer, who is also the FRMP. The term "premises" is used in the NERL as the reference point for customer classification, for the relationship between a retailer and its customers, between a distributor and its customers and between retailers and distributors in relation to shared customers.
- The NERL regulates the exercise of de-energisation and disconnection rights for small customers (and in connection with that, the use of prepayment meters and premises

365 AEMC, *Multiple trading relationships*, final determination, p. 50.

366 Under section 5 of the NERL, customers may be classified as residential or business customers, and business customers may be classified as small or large customers.

367 The NERL more readily accommodates separate connection points being treated as separate premises. Each connection point can have a separate NMI and can be separately disconnected. For customer classification purposes, two or more premises can be aggregated, so a large customer at a single site does not becomes a small customer merely by reason of having more than one connection point.

Similar observations were made in the *Multiple trading relationships* final determination. See p. 49.

where there is life-support equipment). Disconnection is regulated at the connection point under the NERL, presumably because it occurs at that point.[368] If there are two retailers at a connection point but disconnection can occur only at the connection point, if one retailer exercises its disconnection rights, supply under the second retail contract will also be disconnected.

The Commission has identified three possible approaches to address the above points:

1. Under the first approach, both large and small customers would be permitted to establish multiple trading relationships behind one connection point. Supply would be settled at each NMI. For the purposes of the NERL:
   - The 'premises' as currently defined would be used for customer classification purposes and matters such as the regulation of the use of prepayment meters and the obligation to offer standard terms.[369]
   - Each NMI would be treated as separate 'premises' for the purpose of other provisions dealing with the retailer's relationship with its customers. For example, provision would be made to allow each retailer to implement a hardship policy or make a standing offer without impacting the other retailer. Similarly, provision would be made to allow retailer of last resort (RoLR) arrangements and deemed contracts for move-in customers and carry-over customers to continue to operate as intended without competing retailer claims.[370]
   - Provision would be made to limit de-energisation to individual NMIs but where that is not possible, de-energisation of all NMIs behind a connection point would be permitted. Retailers would have a duty to inform the other retailer but would not be liable to the second retailer.[371]
2. The second approach would be the same as the first, except that multiple trading relationships behind one connection point would only be permitted where separate disconnection of each settlement point is possible. This model is consistent with the principle in the NERL that disconnection for hardship customers should be a last resort.[372]
3. The third approach would restrict the use of multiple trading relationships to large customers.

For the first and second models, a specific power may be required in the NERL for the Commission to make rules with respect to the circumstances in which "premises" is taken to refer to the settlement point. This would be similar to the rule-making powers for customer classification in sections 6 and 7 and the rule-making powers relating to the use of interval meters and smart meters in section 237(2)(ia). The NERL and other instruments may also require amendments to clarify the boundary of the obligations of a distributor to provide

368 The definitions of disconnection, for example, refers to the "opening of a connection" to prevent the flow of energy to premises and energization is the "closing of a connection". The "connection" is defined as the physical link between a distribution system and a customer's premises to allow the flow of energy. Section 47 of the NERL provides that "de-energisation (or disconnection) of premises of a hardship customer due to inability to pay energy bills should be a last resort".

369 In relation to prepayment meters, refer to sections 59 and 56 of the NERL. The obligation to offer standing terms under section 22 of the NERL only applies where the premises are connected to the local network (section 22(5) of the NERL).

370 Deemed contacts are provided for in section 54 of the NERL.

371 This was considered in the *Multiple trading relationships* rule change.

372 Section 47 of the NERL.

customer connection services if there are multiple trading relationships at a connection point, since the term "customer connection service" is defined by reference to premises.

The third model does not require changes to the NERL as the provisions relating to disconnection, prepayment meters and deemed contracts do not apply in the same way to large customers. The equivalent provisions for large customers are those giving retailers a right to charge if they are the FRMP for the customer but no contract is in place. These can operate as intended where there is more than one FRMP at a connection point without further change. The Commission's preliminary view is that, under the third model, the introduction of multiple trading relationships lies within the general subject matter about which the Commission may make rules under section 34 of the NEL and section 237 of the NERL.[373]

A.6.6 Next steps

The Commission recommends that AEMO develop a rule change request be submitted to the Commission to allow consumers to engage multiple service providers behind the same connection pointi.e. to give effect to the policy position described above. This would promote competition between retailers, support new business models and provide consumers with great opportunities to engage in demand response.

It is worth noting that AEMO and ARENA (in their joint submission) noted their intent to test this proposal through trials, to assist in a speedier implementation of any rule change made in relation to this. Trialling would present an opportunity to gather further information relevant to the costs and benefits as well as any technical complexity and provide valuable learnings for participants and stakeholders, as well as the Commission, in terms of implementing this option. We consider that these trials could be undertaken in parallel with the development of the rule change request and would provide useful inputs as the detailed design is being developed and considered.

In trials it would be helpful to consider matters that speak to technical and systems perspectives, including:

- metering arrangements that minimise the costs imposed on the consumer and on DNSPs and retailers, such as those discussed previously in this section
- the changes to AEMO's systems necessary to facilitate the proposed rule changes, i.e. some of the changes that were identified in the previously considered *Multiple trading relationships* rule change request
- how the proposed rule change could facilitate virtual power plants (VPPs) integrating into the NEM
- the extent to which this assists with the integration of orchestrated distributed energy resources.

373 This is consistent with the Commission's view in the *Multiple trading relationships* final determination, p. 76.

A.7 Allow third parties to sell demand response in the wholesale market

The Commission considers that allowing third parties to sell demand response into the wholesale market would have benefits including:

- improving the reliability of the power system
- providing greater transparency of the demand side to other market participants
- enabling active participation in determining outcomes in the wholesale market

A.7.1 Overview

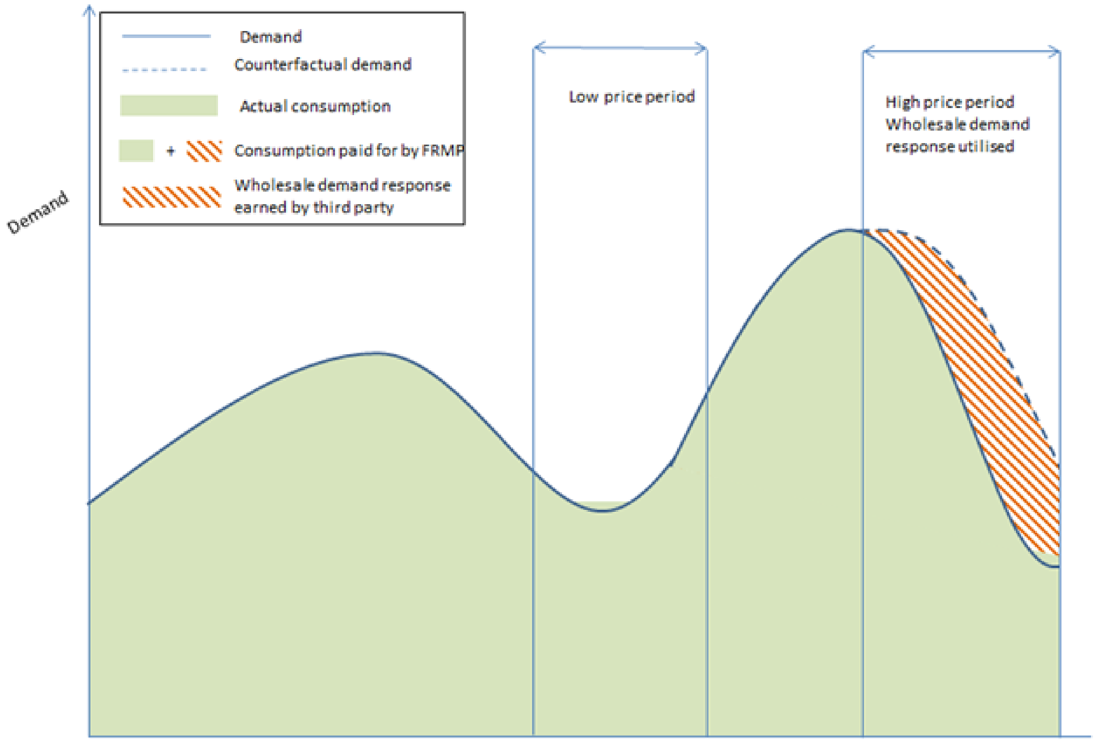
Creating a mechanism that can transfer the value of the wholesale demand response from the existing FRMP to a third party would allow parties – aside from retailers – to offer demand response products.

Figure A.8 demonstrates how the value of demand response could be transferred to a third party. In this example, a consumer reduces consumption during a period of high wholesale electricity prices.

In this figure:

- the underlying physical energy consumption is the green area, which the customer purchases from the retailer
- the striped area represents the amount of demand response - the customer purchases this quantity from the retailer and a third party 'sells' it on the spot market and pays the customer
- the retailer would purchase the green *and* striped areas from the spot market
- if the customer offered demand response by shifting or deferring some consumption (rather than reducing overall consumption), the consumer would need to purchase that electricity from the retailer at the relevant time. This would be in addition to paying the retailer for baseline consumption while offering demand response (the striped area).

Figure A.8: Transferring value of demand response



Transferring the value of demand response would also address a number of the challenges raised by stakeholders in relation to participating in demand response:

- It would allow a consumer to engage a third party for the sale of demand response services into the wholesale market and a retailer for a separate provision of retail energy to the consumer. The consumer would be able to change retailer without affecting its commercial arrangement with the third party.
- The third party would be able to sell demand response in the wholesale market without focussing on the typical role of a retailer in managing and hedging a retail portfolio. Instead it is able to focus on its core service provision.

A similar change has been contemplated previously in the *Demand response mechanism and ancillary services unbundling* rule change request.[374] In the directions paper, we proposed a number of changes to the design considered in that rule change process. These changes are explored in more detail later in this section.

374 Available on the Commission's website, www.aemc.gov.au, under the project code ERC0186. The final determination was published in November 2016.

A.7.2 Nature of the issue

Under the current arrangements, and as discussed above, the supply of energy to a consumer is bundled with wholesale demand response. Retailers are incentivised to utilise demand response where it is efficient to do so; however, they may opt not to for two reasons:

- Established retailers may not have the experience or the organisational expertise to utilise wholesale demand response. At the technical working group meeting, it was noted that for at least some of the existing retailers, the cheapest option of managing wholesale risk was entering into derivative contracts or generating electricity with their own assets. As a result, the most efficient option for a retailer may indeed be to not engage in wholesale demand response. Where a retailer opts not to use wholesale demand response, this could conceivably co-exist with a third-party aggregating demand response from that retailer's customers to offer wholesale demand response.
- Engaging a consumer to provide wholesale demand response has associated upfront and ongoing costs. These transaction costs include the costs of engaging customers, explaining what demand response actually is, installing necessary equipment and agreeing to conditions. The costs generally increase with firmness of the wholesale demand response. The payback period for these costs may be greater than the terms of the retail contract, leaving the retailer exposed to the risk of not recovering their costs if a customer changes retailer. In addition, for some retailers, utilising wholesale demand response may require changes to IT and billing systems which would have associated costs.

In addition, there are challenges for third parties looking to provide wholesale demand response. Third parties can only do so currently by either being a retailer themselves, or having a commercial relationship with a retailer. However, there are limitations with these options:

- Third parties could be exposed to risk if consumers switched retailers to one that they didn't have a deal with. This could only be avoided if the third party was able to enter into an agreement with all possible retailers. As retailers all have individual, unique ways of risk management it is unlikely that a third party would be able to contract with all possible retailers.
- Demand response aggregators may not want to become retailers. They may not necessarily have the capabilities to be a successful retailer. Retailing electricity typically requires expertise in risk management, marketing, IT systems administration and being able to meet prudential requirements. The third parties looking to provide wholesale demand response may instead be experts in load production processes, and dispatch / control technologies. Retailing electricity also require registering and meeting the prudential and consumer protection requirements set out in the NER.

As such, it is difficult for third parties to facilitate demand response under the current framework.

A.7.3 How this recommendation would resolve the issue

This recommendation would address the above issue by introducing a mechanism that would facilitate demand response from third parties in the wholesale market. This would allow demand response providers to be recognised on an equal footing with generators in the wholesale market.

Below, we have set out how we consider this option would work. Note that we have not specified which party would determine the baseline - this is discussed later. The concepts of baselines are explored in Box 8 below.

BOX 8: WHAT IS A BASELINE?

A baseline is a point-in-time estimate of expected behaviour. It is similar to a forecast in many ways. The key difference is that a baseline attempts to isolate and discount the effect of a particular variable. In the context of setting a baseline for demand response, a baseline is trying to answer the question of 'what would demand have been in the absence of any demand response?' For most consumers, this would mean trying to assess what their consumption would be under their existing retail contracts in the absence of demand response.

Specific to wholesale demand response, a baseline tries to emulate the behaviour of a consumer in the absence of any response to short term changes in the wholesale price for electricity. The baseline for a generator is conceptually zero - if the generator was not responding to the wholesale price, the level of generation would be zero.

Registration, classification and accreditation

Under this proposal, a new market participant category would be introduced: a "Demand Response Service Provider" (DRSP). This participant would be the only participant class that is able to sell demand response into the wholesale market through this demand response mechanism.

A DRSP would need to register as such with AEMO. The process for registering as a DRSP would be similar to registration as a Market Ancillary Service Provider. Eligibility for registration would require demonstration of:

- The ability to comply with the relevant parts of the NER
- The intention to classify load as demand response load (see below) within a reasonable period of time.

Following registration, the DRSP would need to classify loads as 'demand response loads'. This may require systems changes to facilitate the classification. We anticipate that there would need to be a process for assessing the resources that are being aggregated but this would occur after registration during the 'classification' stage.

Depending on the party setting the baseline, classifying a load as a demand response load may also involve providing AEMO with information for the purposes of determining the baseline.

We are proposing that the retailer would not be able to opt out on behalf of its customers. That is, retailer participation in the mechanism would be mandatory.

Participation in wholesale market

We consider that all DRSPs would need to be scheduled for three reasons - all of which are important in relation to promoting reliability outcomes in the NEM:

- it provides greater transparency to the rest of the market of the intention of demand side resource to respond to wholesale prices
- it provides the market operator with greater visibility of the quantity of available demand response which would contribute to reliability outcomes
- it provides for better risk allocation by placing more operational obligations on the DRSP.

It is also worth noting that the loads being aggregated for participation in FCAS markets (under the Market Ancillary Service Provider framework) are effectively scheduled for the purposes of providing FCAS. As such, we consider that for a DRSP to participate in the mechanism, it must have an aggregate capacity above the threshold at which resources can be scheduled in the wholesale market. This threshold is 5 MW.[375]

It is not envisaged that there would be a minimum size for an individual load to become a demand response load. While larger loads may be easier to set baselines for, it is likely that baseline methodologies would be able to accommodate residential customers when they are aggregated to a sufficient scale. For example, a collection of 100,000 households may behave in a more predictable manner than 10 industrial loads. While we are not proposing to restrict the size of the demand response load, it must form part of an aggregate portfolio that could be scheduled.

Bidding/information provision

At all times, a DRSP would be required to submits bids into the wholesale market. These bids will appear in pre-dispatch and ST-PASA and therefore would be visible to the market. The bids would inform forecasts of price such that they reflect any scheduled demand response.

However, we note that because the DRSP has limited control over the operational decisions being made by the consumer (particularly in relation to the part of the consumers' load which is not subject to demand response controls), this information may not be as accurate as the information submitted by generators into pre-dispatch and ST-PASA. We do not consider that DRSP would provide information into MT-PASA as information projecting expected demand response in this timeframe would be unlikely to be useful.

Aside from MT-PASA, the DRSP would be subject to the same obligations regarding information provision as other scheduled generators e.g. pre-dispatch and ST-PASA. By doing

375 We note this would be consistent with AEMO treatment of batteries. Currently batteries with capacity greater than 5 MW are scheduled.

so, the demand response bids would be accounted for in pre-dispatch prices and other market participants would be able to factor this into operational decisions. It would also provide transparency to AEMO regarding the quantity of price responsive load. Considering that it is likely the DRSP would only be dispatched for demand response during high price periods, the DRSP would be able to bid unavailable for the majority of dispatch intervals where it does not anticipate offering demand response. When the DRSP intends to be dispatched, it would be required to submit its availability and price/quantity offers.

The DRSP would only be responsible for submitting offers for the quantity of demand response – the difference between the baseline consumption and the projected actual consumption. These quantities would be equivalent to the amount of 'generation' the DRSP is offering.

Dispatch

The DRSP would be dispatched in the same manner as a scheduled generator. If its offer to reduce demand is cleared through the wholesale market, it would be dispatched to reduce consumption by the amount it is cleared for.

Depending on the nature of the load, it would have ramp rate constraints on how quickly it is able to ramp up (turn off load) and ramp down (restore load). The constraint on how quickly a load can be restored will be particularly important for loads that can be shut off quickly but takes time to restore. This could be treated as a dispatch inflexibility profile for each DRSP. A single DRSP may have a range of customers with different ramp rates. Consideration would need to be given to whether a DRSP would be able to bid at a certain quantity with a certain ramp rate at a certain price, and another quantity with a different ramp rate at a different price.

The consequences of not meeting dispatch would be consistent with the dispatch targets for scheduled generators. Compliance with dispatch would be assessed by the AER and the DRSP may be required to pay costs such as FCAS causer pays costs.

Settlements

Each NMI for a demand response load aggregated by a DRSP would have two data streams attributed to it for periods where the DRSP is scheduled to provide wholesale demand response.

- The baseline load for each trading interval as determined using the relevant methodology
- The demand response (which would be the difference between the actual metered load and the baseline load).

The baseline load would be attributed to the FRMP, the retailer, through settlements (and hence will be billed to the consumer) and the demand response would be attributed to the DRSP as generation. Both parties would pay/be paid the wholesale price for the trading interval in which the demand response occurred.

Differences from *Demand response mechanism and ancillary services unbundling* rule

change request

In the final determination for the 2016 demand response rule change, the Commission decided not to introduce the proposed mechanism that was submitted by the COAG Energy Council for that rule change. The above design is different to the mechanism considered in that rule change process:

- demand response would be scheduled facilitating transparency about demand side participation
- it would not be contingent on a retailer opting in on behalf of its customers, the option discussed above provides the consumer with the choice of participating in wholesale demand response irrespective of their retail arrangements
- this model would be applied to aggregated small customers - providing more opportunities to small consumers who have had fewer opportunities to participate in wholesale demand response
- we are considering further who should set the baseline - whether it should be set by the DRSP as opposed to being set centrally, this is discussed further below.

A.7.4 Benefits and costs

The Commission considers that allowing third parties to offer demand response into the wholesale market could have a number of benefits including:

- Providing consumers with greater opportunities to participate in wholesale demand response by allowing additional parties to provide demand response and so promoting competition. This would also have the effect of potentially decreasing prices in the wholesale market.
- Improving the reliability of the power system. In many instances, wholesale demand response can more efficiently contribute to reliability than building new generation. this is particularly true when a tight supply-demand balance is only forecast to occur for a short period of time.
- Providing greater transparency of demand side participation to other market participants, which will help market participants to make more efficient decisions in both operational and investment time frames on both the supply and demand side of the market.

However, there are also a number of costs or questions that are associated with this option. These include:

- costs associated with system changes, including to AEMO's settlement systems
- risks that may be imposed on parties not participating in demand response, depending on how the baseline was to be determined
- costs associated with installing equipment or changing systems to schedule the demand response
- costs associated with applying this to aggregated small consumers.

The latter three of these are discussed further below. Given these are not insignificant issues, the Commission considers that these need to be explored further - in relation to feasibility, practicability and costs.

A.7.5 Issues for further consideration

There are a number of aspects of this potential mechanism which need to be explored before finalising a possible design. These include:

- baselines
- scheduling the demand response
- application to aggregated small consumers

Baselines

What are baselines used for?

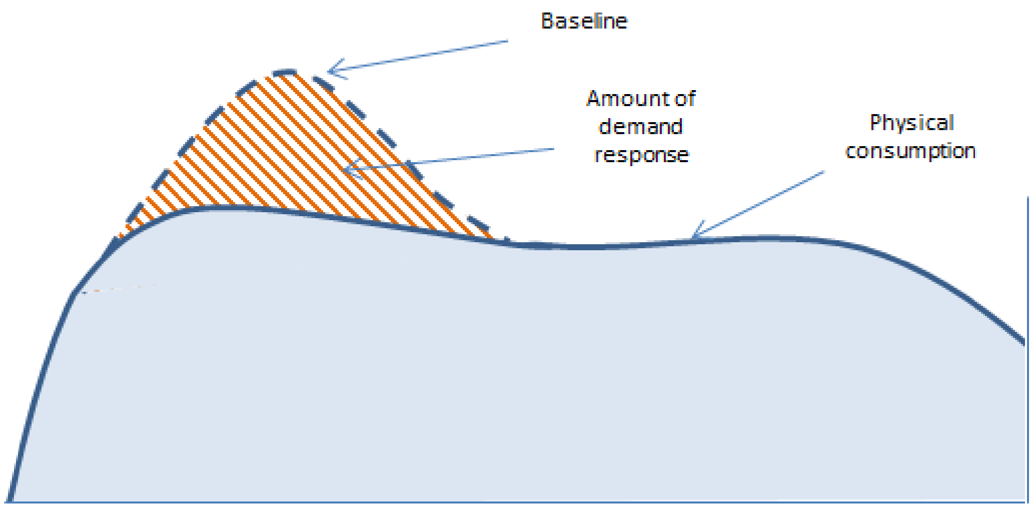
Baselines are used to determine the extent and value of demand response. Baselines for wholesale demand response are used by market participants under the current arrangements. Two examples include:

- **A consumer with direct spot price exposure undertaking wholesale demand response on its own accord, in order to reduce its electricity bills**. To determine whether a consumer should undertake demand response, that consumer would have to weigh the costs and benefits of a reduced level of consumption relative to a baseline level of consumption. If the net benefit to the consumer is greater when the load is reduced, it makes sense for the consumer to undertake demand response. As the consumer has control over their facility, they would know what their effective baseline would be. In this situation, the baseline only involves one party.
- **A retailer that has a contract with a consumer for wholesale demand response in which the retailer can pay the consumer to reduce consumption**. In this situation, the baseline is used to determine the amount of demand response the consumer has provided. The greater the difference between the actual consumption and the baseline, the more the consumer will receive from the retailer. The two parties to this arrangement are able to agree on the methodology for determining this baseline. As a result, this places pressure on the baseline to be accurate - the retailer may seek to make sure that the baseline is as low as possible to reduce payments and the consumer may seek to inflate the baseline to increase its payout. (The relative bargaining power of the parties may affect the outcome here.) It is important that:
  - the baseline is as accurate as possible
  - the upside and downside of the baseline is shared between the two parties and to the extent that either party is not benefiting from the arrangement, a new arrangement can be agreed or it can cease.
  - the discipline imposed by both parties that contributes toward the improvement of the baseline over time, i.e. both parties have the incentive to adjust and correct the baseline over time to minimise their potential losses.

Under the Commission's recommended approach, a baseline becomes formalised. This is because the model requires retailers to act as a party to a baseline.

The baseline is used to determine the quantity of demand response. The difference between the actual demand and the baseline demand represents the quantity of demand response, shown in Figure A.9.

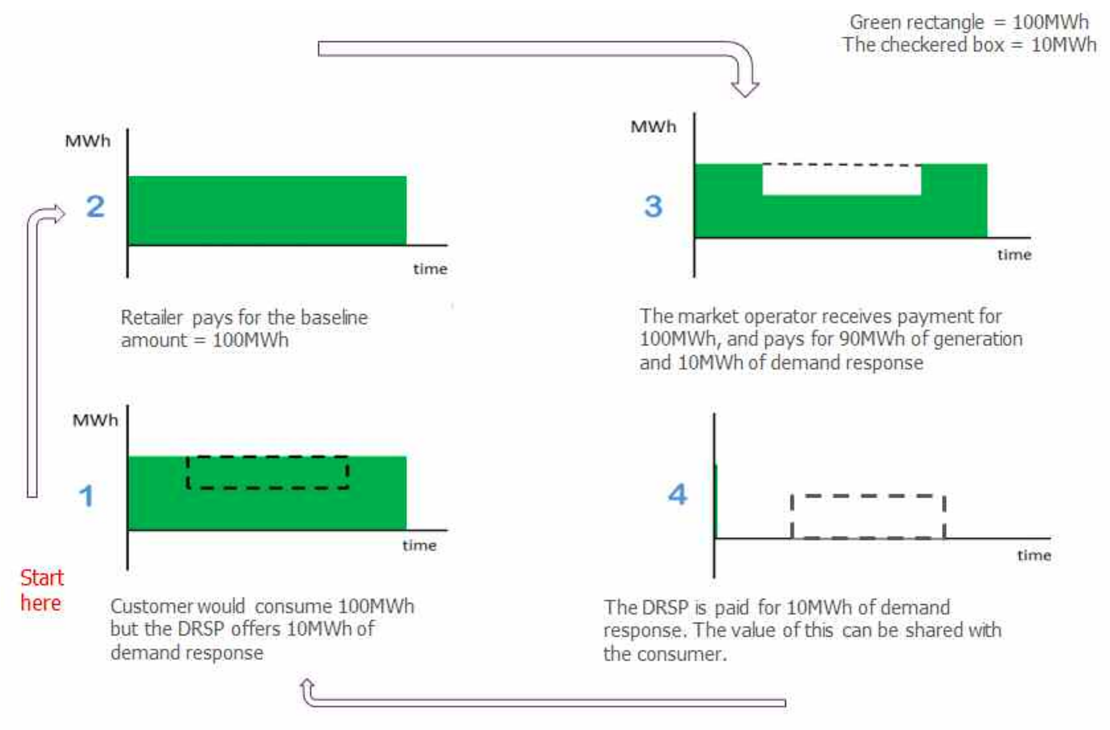
Figure A.9: Using a baseline to determine the amount of demand response



The determined quantity of demand response is then used to transfer the value of demand response to a third party - the DRSP - from a retailer.

In simple terms, the retailer is charged the level of demand that would have occurred in the absence of demand response - the baseline quantity. In reality, some lesser amount of electricity is consumed - the actual quantity. This results in the retailer paying more into the wholesale market than it is required to for its physical load. The additional payment is the value generated by the third party (the DRSP under this proposal) undertaking demand response. This cycle is demonstrated in Figure A.10 below.

Figure A.10: Payment that accrues for demand response



Challenges when setting a baseline

The challenges with setting a baseline are similar to the challenges with forecasting. A baseline needs to account for a wide range of variables that might influence consumption decisions, including but not limited to:

- the day of the week
- the air temperature
- any seasonal variations
- changes in operational patterns, such as the installation of new machines or working at night instead of day
- availability of other resources including staff or raw materials for making widgets.

Since there is a large number of factors that may affect a baseline, inevitably the consumer is best placed to know the baseline. However, any party (including the consumer) trying to estimate the baseline does not know precisely what the level of consumption would be in the absence of demand response. Models of a customer's behaviour, based on that consumer's previous behaviour and/or the behaviour of similar consumers, can attempt to explain the variation in consumption of electricity and predict future consumption. However, these models will never be able to fully account for fluctuations in consumption.

Another challenge arises when trying to assess the accuracy of a baseline. Because a baseline is not observed but rather is a counterfactual; it cannot be quantitatively assessed for accuracy (unlike a forecast).[376] This makes it difficult to retrospectively assess whether demand response was appropriately quantified or not.

What happens when a baseline is wrong?

When a baseline is wrong (i.e. it does not reflect the consumer's electricity use in the absence of demand response), it means that the quantity of demand response that was accounted for will be wrong. If the baseline is too high, the amount of demand response will be overestimated. If the baseline is too low, the amount of demand response will be underestimated. As a result, either too much or too little value relating to demand response will be transferred from the retailer to the DRSP.

In a single instance, if the baseline is wrong, the demand response will either be over or undervalued.

However, if the baseline is correct *on average*, over time, the fair value for the demand response should be exchanged between the retailer and the DRSP. If it is correct on average, you would expect the over and undervaluation of the demand response to cancel out over time. This will not be the case if either:

- The error in the baseline is not zero on average. This would be the case if the baseline has a tendency to be either too high or too low, which may be the case if either the DRSP or the retailer has the ability to influence the baseline. This is discussed more in a later section.
- The two parties affected by the baseline, the retailer and the DRSP for a consumer, change over time. This could occur if a consumer changes retailer and retains a relationship with the same DRSP. In this situation, it would be likely that either the retailer has paid an inefficiently high amount for the demand or the DRSP has been paid an inefficiently low amount for the demand response it has undertaken (particularly if the demand response occurs infrequently).

When the baseline is not correct on average, it has a distortionary impact on the market. It either results in a retailer facing a cost (ultimately recovered from the retailer's customers) where there was no efficient change in consumption, or a DRSP recovers revenue from the wholesale market that does not reflect the value of any efficient demand side decisions it has made.

For this reason, it is important that there is confidence that a baseline methodology is accurate - to the extent that it has a systematic bias, there are likely to be distortionary impacts on the market.

How accurate should a baseline be?

376 Baseline methodologies are tested to see whether they produce accurate results. This is typically done by assessing the ability to predict historical consumption. In the event that demand response occurs and a baseline is used, there is no way to observe the counterfactual. For more information on assessing forecast accuracy, see chapter 2.

If a baseline is centrally determined, there would most likely need to be a desired level of accuracy. Assessing the accuracy of a baseline is likely to be challenging, particularly over time as the consumer changes behaviour and/or level of consumption. As discussed above, it is important the average error in the baseline is minimised.

When determining how accurate a baseline should be, there is a trade off being made between the administrative costs of improving the baseline and the distortionary impacts of an inaccurate baseline.

One way to improve the accuracy of the baseline methodology is to only allow participants with predictable consumption patterns to participate.

Who should determine the baseline?

There are two parties that could determine the baseline: a central body, most likely AEMO, or the DRSP.

If the baseline is centrally determined, this imposes a number of risks on the market and participants which cannot be easily managed. The risks introduced under this option and the bearer of these risks include:

- An inaccurate baseline methodology. This could in turn result in:
  - A DRSP not meeting its dispatch target. A DRSP might reduce demand by the quantity it is scheduled for; however, if the baseline is poorly set, the difference between the baseline load and the actual load (i.e, the amount of demand response) may not reflect what actually occurred. If the baseline is too high, the DRSP will have provided more demand response than it was scheduled for which will impose costs on the rest of the market and expose the DRSP to compliance risks. If the baseline is too low, the DRSP will not have provided enough demand response and will also be exposed to compliance risks. If the baseline is determined ex-post, the DRSP has limited ability to manage this risk. However, if the baseline is known in real time, it may provide the DRSP with increased opportunities to game the baseline. A DRSP would be able to observe whether it considered a baseline to be 'high' or 'low' in advance of undertaking demand response, which would enable the DRSP to provide demand response when the baseline is considered to be overly high, and not provide demand response when the baseline is considered to be too low. This would potentially introduce a systemic bias where the baseline was more likely to be used when it is overly high.
  - The FRMP paying for the incorrect amount of load. Because the FRMP has to pay for the baseline level of energy, the FRMP is exposed to the risk that the baseline is incorrectly set, resulting in the FRMP being over or under-hedged. The extent of this risk is unclear as the retailer is hedging on the expected behaviour of the load and so this risk is only material to the extent that the baseline methodology estimates consumption to be materially different to what the FRMP has accounted for in its risk management.
- A risk that the DRSP will game the baseline to increase the amount of demand response it sells. While this can be partially addressed through regulation, the DRSP is still

incentivised to inflate a baseline where the benefits of doing so would outweigh the costs. In some cases, gaming the baseline may not be practical or cost-effective; however, there are likely to be opportunities for gaming the baseline across the broad spectrum of participants who could provide demand response. This would impose additional costs on the market and on the FRMP for the load.

- A risk that it will result in retailers pursuing demand response through this mechanism instead of in the manner that they currently can. The introduction of this option in isolation would most likely not deter retailers and market customers from pursuing wholesale demand response in the current way where efficient because doing so would be less costly than being scheduled for demand response in the wholesale market.

A centrally determined baseline methodology has been used in the AEMO/ARENA RERT trials. As noted in AEMO and ARENA's joint submission, feedback from trial participants was the baseline method was not suitable for variable loads or those with solar PV. AEMO and ARENA are working together to review and develop additional baselines to reflect different load profiles and features. The intent is to develop some additional baselines to be captured in time for the second year of the trial. This assessment of baseline options is expected to be completed in mid-2018.[377]

If the baseline is set by the DRSP, the DRSP would have the incentive and ability to maximise the extent of the difference between the actual and the baseline levels of consumption (subject to any rules restricting this, discussed below). In practice, this would consist of the DRSP inflating the amount of load that would otherwise be consumed to increase the quantity of demand response that it is paid for. The retailer has no ability to manage that cost with the exception of preventing its customer from participating.

As a result, regulation would be required to counteract the ability for the DRSP to manipulate the baseline.

This manipulation can be partially addressed by penalising the DRSP if it does not comply with its dispatch targets. This would discourage a DRSP from submitting a baseline that does not reflect the actual intentions of the demand response load. If an inflated level of demand was submitted by the DRSP, the DRSP is exposed to the risk of the wholesale price falling and being dispatched to the inflated baseline level of consumption (and not providing any demand response). To the extent that the DRSP does not meet its dispatch instruction, it would be exposed to compliance risks.

However, if the DRSP has a high degree of certainty that the wholesale price will be high and that it will be dispatched for demand response, the DRSP would be able to submit an inflated baseline and face little risk of being dispatched to consume at that level. To partially mitigate this, some restrictions could be imposed:

- The level of the baseline could be capped based on an assessment of historical consumption. This would prevent a baseline being submitted that exceeded the consumption of the load.

377 AEMO/ARENA, joint submission to directions paper, p. 10.

- A 'sense check' could be applied to the baseline. This would be undertaken by AEMO or the AER ex-post; however, this would partially defeat the purpose of having it submitted by a third party.
- A bid floor could be applied. This would mean the DRSP would not be able to submit demand response offers into the wholesale market that would be dispatched below the bid floor price. In effect, the DRSP would only be able to participate in the wholesale market when the wholesale price exceeds the bid floor.[378]
- An alternative method of regulating baselines set by DRSPs would be to require that they provide their baseline methodologies to AEMO in advance. DRSPs would be subject to penalties if they are found not to be following their authorised methodologies in setting their baselines. The NER or AEMO procedures could specify that DRSPs' methodologies must contain certain basic anti-gaming features, or more general anti-gaming/ good faith obligations could be imposed. A requirement to review and update baseline methodologies periodically (for example, every four years) could be considered.

We would have to consider the design of these restrictions further through the development of a relevant mechanism.

In either case, there are challenges associated with the party that determines the baseline.

In both cases, there are limited incentives on the party submitting the baseline to improve the accuracy of the baseline over time. This may become problematic as the scale of demand side participation in the NEM grows and the effect of inaccurate baselines becomes more significant.

We consider trials should be used to explore different approaches to establishing an effective baseline.

Scheduling the demand response

As noted earlier, the Commission considers that demand response should be scheduled in the wholesale market. This would provide participants with greater transparency regarding the level of demand side participation and allow the wholesale market to clear at an efficient level.

This introduces a range of questions that the Commission considers require further analysis, which would be informed by trialling.

One challenge of having the demand response scheduled in the wholesale market is that, if the baseline is determined ex-post, there is no way to know in real time if the DRSP is providing the amount of demand response that it is scheduled to provide. Currently, generators in the wholesale market provide SCADA information to AEMO to indicate generation levels within a dispatch interval. Because the actual extent of the demand response is not known until actual consumption has been determined and compared against the baseline, a DRSP cannot provide the same information to AEMO as a generator would.

378 A bid floor introduces a number of challenges in and of itself. It is not clear what the DRSP would be required to do if it had been dispatched down and subsequently the wholesale price fell below the bid floor. This would mean that the DRSP could not be cleared but it would presumably be providing demand response at this point in time.

However, the DRSP would be required to provide estimates of the amount of demand response dispatched at the end of each dispatch interval. This would be used by AEMO to potentially adjust the amount of demand response that the DRSP is scheduled for in future dispatch intervals.

It may also be that some or all demand side resources are not well suited to receiving dispatch instructions every five minutes. Some loads may be able to easily turn off following a dispatch instruction but may not be able to respond to later instructions to restore load. There may be existing ways to accommodate this within the NER, such as a dispatch inflexibility profile (as noted above). This may need to be adapted to a portfolio of participants offering wholesale demand response. A challenge may arise in trying to aggregate the 'inflexibility profile' of a range of different consumers.

Application to aggregated small consumers

If a portfolio of small consumers are able to participate in the mechanism to facilitate demand response, this may not be readily accommodated by current market systems. Some of the challenges that would arise include:

- The appropriate level of SCADA required for participation in the wholesale market. It would most likely be prohibitive to require all participants to provide SCADA to AEMO so there may need to be a new method of collecting information regarding the response profile of consumers.
- Appropriately applying a baseline to a diverse collection of consumers. From the point of view of the market, this may not be more challenging than applying a baseline to a group of commercial or industrial consumers; however, baselines would be needed for each individual consumer so that their retailers can be attributed the baseline amount of consumption.
- Accounting for geographic dispersion of demand response. This may be important for any impacts on transmission and distribution constraints and loss factors.
- Accounting for any adverse impacts on networks, particularly distribution networks, of orchestrated demand response. The impact may not be any worse than that of a single large consumer providing demand response; however, there may be reduced visibility of network impacts when following demand response from aggregated small consumers. This issue was also identified by the ACCC who noted that participation in wholesale and network demand response may be complementary; however there are coordination issues to consider in optimising the use of demand response across different markets.[379] For example, wholesale peaks will not necessarily coincide with local network constraints, and the use of demand response from customers within a distribution network may impose costs on the network to manage changes in electricity flows.

379 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

A.7.6 Legal considerations

There are legal and regulatory issues associated with a wholesale demand response mechanism that need to be considered. These issues include the following:

- The model involves operational and commercial risks. A trial would enable these to be better understood and will enable options for risk management and risk allocation to be identified, including the availability and design of financial hedges and their role in the model.
- In relation to the customer – retailer relationship, the model relies on the retailer retaining responsibility for purchasing the customer's baseline consumption from AEMO and the customer in turn paying the retailer. This arrangement will need to be defined contractually, and existing customer contracts may not accommodate it (as they would typically refer to the sale of electricity to the customer based on metering data). While the form of contract will not be defined in the NER or NERR, a trial will enable contract models to be tested and in turn, to understand how the contract is likely to be characterised and regulated. One issue is whether the arrangement is a financial product for the purpose of the Corporations Act. A second is the extent to which the NERL or NERR applies when the customer is paying at the baseline (i.e. paying for electricity it has not consumed), and whether consumer protections in the NERR need to be enhanced for small customers entering into these arrangements. Amendments to the NERL and NERR are likely to be required to support this model.
- The potential impact of the new arrangements on existing retail contract and hedging models needs to be better understood. For example, retail contracts for larger customers typically include provisions (which may be mutually beneficial) restricting the use of demand management such as contracted load parameters or constraints on the sale of demand management capability without retailer consent. This reduces the extent of any load variability, making it easier for the retailer to hedge this load. This reduces the costs paid by the consumer. If a consumer is providing demand response through a third party, this may not be permitted under some retail arrangements.
- If the customer-DRSP relationship involves retail supply, the model will need to accommodate multiple retailer relationships at a connection point. This raises a range of issues under the NER and the NERL/NERR, as considered further in relation to Recommendation 2 at Appendix A.6.
- As the retailer is being settled for the 'baseline' level of energy (not its customers' actual electricity use), this may have consequences for the retailer's liability for renewable energy certificates (RECs) under the *Renewable Energy (Electricity) Act* 2000(Cth). This Act provides for a retailer's liability to be based (primarily) on its acquisition of electricity from AEMO, which is to be determined based on "metering data used for AEMO … settlement statements".[380] The Commission considers that this requires retailers' REC liability to be determined based on the actual electricity usage of their customers, rather than the baseline use. This outcome may be able to be achieved without changes to that Act, by allowing retailers to continue to have access to actual metering data for their

380 *Renewable Energy (Electricity) Act* 2000 (Cth) s. 32(1); Renewable Energy (Electricity) Regulations 2001 (Cth) s. 21(1)(a).

customers (as they do currently), in addition to the baseline data. This would enable a retailer to calculate its REC liability based on its acquisitions from AEMO at baseline levels (which include acquisitions of both electricity and demand response) minus the megawatt hours of demand response by its customers.

A.7.7 Next steps

We consider that a well functioning framework allowing third parties providing demand response to be recognised on an equal footing with generators in the wholesale market could provide value to consumers and to the market as a whole. In particular, the key benefit of this option is that would allow parties aside from retailers to offer demand response products. However, we have identified a number of issues that will need to be considered further.

There has been significant interest from multiple stakeholders - representing a range of industry participants - who have noted that they intend to submit a rule change request to the Commission to implement our a way for demand response aggregators to be treated on equal footing with generation i.e. implement a demand response mechanism. The Commission welcomes this - integrating demand response into the wholesale market is a critical component of facilitating the energy sector transition and so we do not consider there should be any delays in progressing this issue. If the Commission has not received a rule change request from one of these stakeholders by the end of August 2018, then it will draft a rule change request that the Energy Security Board can submit.

In addition, AEMO and ARENA will be trialling in-market demand response. The objective of this trial is to demonstrate the potential to increase wholesale market competition by improving access of demand-side resources to spot market pricing. Under the trial, demand response would be provided to the spot market by the customer / aggregator which displaces the energy which would otherwise have been provided by the marginal generator. As an in-market trial, the majority of the revenue would be earned in the spot market, paid for by retailers and dispersed to demand response providers through the market settlement system.

The Commission thinks informing some of the policy decisions on these aspects through trials, rather than solely through analysis would be beneficial. For example:

- how can the demand side best be scheduled in the wholesale market?
- which party should be responsible for setting the baseline?
- how would this mechanism coexist with other demand response initiatives underway?

Trials would inform the implementation issues arising from various design choices relevant to the above.

A.8 Other options considered

In assessing options for facilitating demand response in the wholesale market, the Commission considered two other options but ultimately decided not to recommend them. These options were:

- a retailer incentive fund that was outlined in the directions paper

- a requirement for market customers to schedule load.

More detail on these options is provided below.

A.8.1 Retailer incentive fund

Summary of option

This option would create a retailer incentive fund or scheme to develop and market demand response products. The retailer incentive scheme would be a pool of funds accumulated over time that could be accessed by retailers to assist them in providing demand response products. The objective of the fund would be to encourage retailers to make efficient decisions in relation to offering demand response products, such that consumers' demand for electricity in the wholesale market is met at the lowest total system cost. The scheme would reward retailers for implementing demand response options that deliver net cost savings to their customers, where it is efficient to do so.

Details of option

As outlined in the directions paper, the retailer incentive fund would operate as follows:

- Each year the AER would set the total value of the fund.
- Retailers would be required to contribute to the fund depending on their market share as of 1 July each year. For example, if a retailer had 10 per cent market share it would pay 10 per cent of the yearly costs of the fund.
- The funds would be accumulated through market participant settlement. Retailers would apply to the AER with their innovative proposals and the amount of money that they wished to receive from the fund.
- The AER – potentially in consultation with its consumer challenge panel – would determine what retailers' products would qualify for payments from the fund.
- There would be a set of principles set up to guide these decisions. For example, preference could be given to smaller retailers to develop their demand response products.
- The fund would only exist for a defined period of time until there are sufficient demand response products being offered in the market.

In submissions to the directions paper, stakeholders presented strong opposition to this option. Stakeholders noted that retailers already had incentives to undertake demand response where it is efficient and this option would constitute a distortionary intervention in the market.

The Commission agrees with this feedback and so has not considered this option further.

Reasons for not considering option further

While this proposal would likely facilitate more demand response in the wholesale market, it would also constitute a significant impost on the retail market which would result in costs flowing through to consumers, particularly those who are not equipped to participate in demand response. There would be costs for the AER in establishing the process for collecting and administering the funds. Retailers would incur administrative costs if they chose to prepare and submit proposals. Costs would also be levied on retailers in contributing to the fund, which would also be passed on to consumers. This may ultimately impose unnecessary and inefficient costs on the consumers which is not consistent with the NEO.

Considering that retailers already have an incentive to undertake demand response where it is efficient, the introduction of an additional payment for demand response would be expected to have a distortionary impact on retail and wholesale markets.

In stakeholder submissions, it was also noted that there are existing incentives for retailers to undertake demand response where it is efficient. In addition, bodies such as ARENA are able to provide assistance to promote innovation where ARENA considers this is appropriate.

A.8.2 Requiring market customers to schedule load

As discussed in chapter 4, the Commission has also considered requiring retailers to schedule load in the wholesale market. While the Commission is not proposing that this option be implemented at the current time as it is unlikely that the benefits would outweigh the costs, it encourages retailers to explore ways in which that can play an increased role in the development of the two-sided wholesale market.

B DISPATCHABILITY AND FLEXIBILITY

BOX 9: KEY POINTS

- An increased penetration of variable renewable generation and a more responsive demand side may result in rapid, unpredictable and increasingly large changes in supply of electricity.
- This is likely to present challenges to the system to maintain the balance of supply and demand. The rest of the system must provide sufficient flexibility and responsiveness to meet changes in supply from variable renewable generation.
- The Commission has examined whether the existing framework provides sufficient incentives for generation and load to be flexible and dispatchable.
- It has concluded that currently in theory, market participants are provided appropriate incentives to respond to meet the challenge of rapid and unpredictable changes in the supply-demand balance in both operational and investment timescales.
- However, the Commission notes that these conclusions are predicated on a number of others arrangements both inside and outside of the reliability frameworks working adequately. For example, distortions arising from interventions in the market for reliability or security reasons may influence the incentives provided through the energy and contract market for dispatchability and flexibility.
- Quantitative analysis undertaken by the Commission further supports these findings based on current experiences. Specifically, the Commission has found that:
  - There is some limited evidence that the increase in renewable penetration is leading to an increase in the demand for ramping at the extremes in South Australia.
  - More importantly, there appears to be some spare ramping capacity available in regions of high renewable penetration
  - Analysis also shows that high demand for ramping (on a 5-minute basis) in South Australia is associated with high prices. These outcomes appear to have been driven to some extent by the off-peak hot water load that occurs late at night, and is a phenomenon that has been present in the market for a long time. These outcomes demonstrate that the market provides price signals for ramping, and that these price signals have supported the adequate supply of ramping for many years. It could be argued that this is a relatively predictable phenomenon and that ramping events from variable renewable generation may not be so predictable – it is these effects that we will work together with AEMO on in their analysis of South Australian issues
- The Commission has also examined ramping products introduced in overseas jurisdictions to meet similar challenges in those jurisdictions. It has concluded that those products appear to address problems that are specific to those markets' designs and that are not present in the NEM. Consequently, the Commission does not consider that ramping

products of the type examined overseas are appropriate in the NEM without radical re-design of existing market arrangements.

For an electricity system to work effectively and contribute to reliability, supply must equal demand plus reserves (near) instantaneously. As supply or demand changes, for example, due to changing levels of consumption or output of generators, the rest of the system must respond to maintain the balance of supply and demand.

Achieving a balance of supply and demand may be more challenging in the future due to an increased penetration of variable renewable generation in the system and a more responsive demand side of the market. This is because it may result in:

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

Some commentators have suggested that the existing market arrangements may not address these challenges in the future. Put another way, they have suggested that there may in the future be insufficient dispatchable or flexible generation or load to balance supply with demand as that balance changes unpredictable or rapidly.

This appendix is structured as follows:

- Appendix B.1 elaborates on the concepts of dispatchability, flexibility and ramping
- Appendix B.2 describes the existing framework to incentivise dispatchability, flexibility and ramping, and possible limitations to this framework
- Appendix B.3 provides quantitative assessment of ramp-rate data
- Appendix B.4 explores ramping markets and products which have been introduced in three overseas markets to address the challenge of increase variable renewable generation in those markets.

B.1 What are dispatchability, flexibility and ramping?

Currently, the terms 'dispatchability' and 'flexibility' are not defined in the NEM framework.

Broadly, dispatchability refers to sources of energy or load that can respond to instructions to increase or decrease output or usage. Resources that are dispatchable are valuable in that they can maintain the balance of supply and demand because their output can be instructed to adjust in response to changing conditions.

Similarly, flexibility broadly refers to the ability for generation or load to respond to changes in demand and supply in a timely manner. There needs to be sufficient "headroom" in terms of reserves in the market so that resources can respond to changes to demand and supply so that the market can remain secure and in balance. Resources that are more flexible are more valuable in maintaining the balance of supply and demand because they can adjust more rapidly to changing conditions than less flexible generators and load.

However, precisely defining dispatchability and flexibility is difficult. For example:

- one generating unit may be able to adjust its output more that another over a relatively long time period (say, 3 hours) but less over a relatively short time period (say, 5 minutes). Which is the more flexible?
- Some generators are dispatchable when they decrease their output but not when they increase their output.
- How controllable must a resource be to be considered dispatchable?

These complications create difficulties in defining flexibility and dispatchability.

As discussed throughout the rest of this appendix, the Commission considers that the current market arrangements already sufficiently values these concepts in such a way that takes account of these complexities and provides incentives to deliver the type of flexibility and dispatchability valued by the system. Consequently, the Commission is not seeking to define precisely the concepts of dispatchability and flexibility in the NEM and considers that doing so risks creating perverse outcomes if the definitions do not correspond to the physical requirements of the system.

It is worth noting in this context, that the proposal for qualifying contracts in the Guarantee is that contracts will qualify if there are "any wholesale contract with a direct link to the electricity market which a liable entity uses to reduce exposure to high spot prices."[381]

In contrast, ramping is a concept defined already in the NEM. The NER define ramp rate as: "the rate of change of active power (expressed as MW/minute) required for dispatch". Clearly, this is a related concept to both dispatchability and flexibility; for example:

- more flexible generators/consumers have a higher ramp rate than less flexible generators/consumers
- generators/consumers that are not dispatchable cannot respond to instructions to increase their power output.

In order to maintain the balance of supply and demand (near) instantaneously, generators and consumers may need to change their output or load in timescales much shorter than five minutes. However, this is the domain of frequency control ancillary services – a system security issue – and is not in scope for this review.[382] Therefore, for the purpose of this

381 See: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/TWP%20-%20Qualifying%20Contracts%20-%20June%202018.pdf

382 This is instead being considered as part of the Commission's *frequency control frameworks review*.

review into reliability, we are interested with the rate of change of supply (and demand) – ramping – over time periods greater than or equal to five minutes.

B.2 Incentives for dispatchability and flexibility

The NEM currently provides incentives (or rewards) for generators and load to be flexible and/or dispatchable. This occurs through the combination of the ancillary services, spot and contract markets.

As noted above, ancillary services are not in scope for this review and the incentives provided through ancillary services markets are not discussed in this report. Consequently, this section focuses on the incentives on generators and loads to be flexible and/or dispatchable through the spot and contract markets. It also discusses the specific case of whether market participants are incentivised to make efficient unit commitment decisions in order to provide an appropriate amount of reserves to the market.

B.2.1 Spot market incentives

Dispatchability and flexibility are recognised and rewarded in the spot market.

Consider what happens when there is a sudden and unexpected tightening of supply and demand, leading to a corresponding increase in prices in the energy market. Those generators that are able to adjust their supply upwards deliberately and quickly will be rewarded for doing so through the high prices received for their generation output. Similarly, those generators that are able to adjust downwards deliberately are able to avoid incurring losses when prices suddenly and unexpectedly fall below their short run costs.

Conversely, generators that are less flexible or cannot actively respond to the change in the wholesale price bear an actual or opportunity cost for this. Large-scale coal generators who ramp up and down slowly, or who have high minimum generation levels, may face low or negative prices in the spot market as a result.

The incentives for both dispatchability and flexibility discussed above also inform efficient operation of plant - including matters such as plant maintenance, staffing, fuel resourcing, and importantly unit commitment decisions (as discussed below and in appendix D).

These incentives also flow through to efficient investment decisions. Expectations of the market not delivering sufficient flexible or dispatchable plant will translate into expectations of an increased frequency of high price events. This in turn provides incentives for market participants to invest in flexible and dispatchable generation capacity (or demand response) capable of taking advantage of these typically fleeting high prices.

The incentives provided through the wholesale spot market for the provision of dispatchability and flexibility are framed by the reliability settings.[383] Rewards for being flexible and dispatchable are capped at the market price cap while losses for being inflexible or non-dispatchable are capped at the market floor price.

383 The market price cap, cumulative price threshold, administered price cap and market floor price. These limit the extent to which wholesale prices can rise and fall and are set at a level so as not to interfere with the price signals needed for efficient investment and operation.

B.2.2 Contract market

The contract market also plays an important role in valuing flexibility and dispatchability. Variable renewable generators are unlikely to enter into firm derivative contracts to the same extent as dispatchable generators, because they cannot be confident they will be generating when prices are high, leading to potentially large payouts under the contract that are not covered through revenue from the spot market. In contrast, dispatchable generators are better able to offer these contracts, and so are rewarded through the contract market to the extent that demand for, and thus the value of, these contracts is high.

Another benefit from participating in the contract market is that the price received for generation output is more certain, thus reducing risks. Similarly, load that is able to reduce its consumption can command a better price in the retail contract market because it reduces the risk to its counterparty of high spot prices.

The contract market also rewards flexible generation and load. To the extent that spot prices are becoming more volatile, retailers and other load-side market participants should have greater demand for contracts which manage their exposure to spot price spikes - in turn raising the price of these contracts. Inflexible or variable renewable generators typically do not offer contracts because they risk high payouts that are not covered by revenue generated through the spot market. This is because they are unable to adjust their generation quickly enough in response to sudden and unexpected spot price rises. Flexible generators face less of this risk and are therefore more likely to enter into contracts, and so are rewarded in this market.

Furthermore, these incentives for both dispatchability and flexibility play into the investment timescales. High contract prices provide incentives for flexible and dispatchable generators/load to enter the market, and provide the mechanism by which investments can be bankable.

As discussed further in chapter 5 there are anecdotal examples of participants that have variable renewable generation investing in technology or equipment to "firm" up their capacity in order to respond to increasing contract prices that "value" dispatchability and flexibility.

In addition, dispatchability and flexibility requires adequate plant maintenance, staffing, fuel resources and unit commitment decisions (discussed below and in chapter 5). The market signals discussed above also incentivise the plant operator to manage these aspects as well.

The ACCC has recently identified concerns with transparency of hedge contracting its final report of its Retail Electricity Pricing Inquiry.[384] It is recommending changes to improve transparency and competition in the contract market. This is discussed in more detail in chapters 3 and 5 of this report.

384 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

B.2.3 Unit commitment decisions

In any electricity system, decisions need to be made ahead of real time to start (or stop) individual generating units. The decision, depending on generation technology, may need to be made many hours in advance of the need to produce energy, and may have significant cost. This decision is known as the "unit commitment decision". In the NEM, the unit commitment decision is, in effect, taken by individual market participants. The unit commitment decision is distinct from the centralised dispatch process undertaken by AEMO.

Historically, unit commitment decisions in some pre-NEM markets (e.g. Vicpool) were undertaken centrally. However, this was changed in response to recognition that central commitment of generation limits the efficiency that occurs through rebidding.[385] For a discussion of rebidding, see appendix D.

In the NEM, the 5-minute spot price provides a signal of the value of energy during that five minute dispatch interval. In and of itself, the 5-minute spot price provides limited indication of the value of energy in the future. This has led some commentators to assert that there is no transparent and explicit value for reserves, flexibility or dispatchability in the NEM, and that as a consequence these characteristics are not (or will not be in the future) sufficiently valued and therefore will not be sufficiently provided. The Commission agrees that there is no transparent and explicit value for flexibility and dispatchability in the NEM, but considers that this does not of itself necessarily lead to the conclusion that these are (or will be) under-valued and therefore under-provided.

In drawing their conclusions, these commentators appear to have overlooked that theoretically market participants take account of their estimations of the future spot price together with their sold financial contract positions and conditions at their individual plant in making their unit commitment decisions.

Market participants are informed by AEMO forecasts of spot prices (themselves informed by information provided by market participants through pre-dispatch), which are also reflected in forward contract prices, as well as the market participant's own views on the supply and demand balance. A comprehensive description of the information available to market participants at different moments in time in advance of dispatch was provided in appendix D of the directions paper.

Market participants do not focus only on the next five minutes – the prospect of potential high spot prices in the future provide incentives for market participants to structure their bids so as to commit units ahead of time and hence provide reserves to the market. This is the case even if the market participant makes a loss during any individual 5-minute interval (or indeed a number of successive 5-minute intervals).

The factors which influence unit commitment decisions made by market participants are complex, and include:

- their estimation of the likelihood of spot prices being at a variety of levels in the future (i.e. their probability-weighted expectation of future spot prices)

385 CRA, Short-term forward market, Report for South Australia Department of Treasury and Finance, 30 June 2004.

- their sold contractual position and their aversion to making potentially large losses through their contracts if not also generating when the spot price is high
- their ability to ramp generation from a variety of operating states in order to maximise their output to capture high spot prices and minimise their generation to avoid low spot prices
- any fixed costs associated with starting and stopping units, as well as the costs associated with running the units (for example at minimum output)[386]
- physical conditions of the generating units, for example if repairs or maintenance are required at a given time.

If a market participant deems that the probability and extent of high spot prices in the future is low, then, depending on a variety of other factors including those described above, it may choose to avoid costs and structure its bids so as not to commit (or de-commit) plant. In effect, it considers that the prices that it would earn would not compensate it for incurring the short-run costs (including fuel and unit commitment costs) of running.

The consequence of this would be to steepen the supply curve. In the event that additional generation is required to meet demand, those generators that remain committed, and so are able to supply, receive a higher spot price. This in turn influences market participants' estimations of the likelihood of spot prices being at a variety of levels in the future. A generator's commitment decision should therefore be iteratively determined based in part on future spot price expectations (and changes in these expectations), which are in turn should be informed by all generators' commitment decisions. See the box below for more detail.

BOX 10: A SIMPLE EXAMPLE OF ITERATIVE UNIT COMMITMENT DECISIONS IN THE NEM

The following example is simplified, but illustrates the iterative process discussed above.

There are four generators, A, B, C and D, which each have individual expectations of the probability weighted average spot prices in the future, and different "thresholds" for the probability weighted average spot prices above which they will commit their plant. This threshold is influenced by a variety of factors, including their contractual position. In reality, it is difficult to distil these concepts into precise numbers, but for the purposes of this simplified example unique numbers are provided.

Each generator has to make a commitment decision, say, six hours in advance of real time. 24 hours in advance of real time, the situation is as follows.

386 Market participants may also factor in the prospect of being directed by AEMO, and hence receiving compensation.

GENERATOR	INDIVIDUAL PROBABILITY-WEIGHTED EXPECTATION OF FUTURE SPOT PRICES ($)	THRESHOLD FOR COMMITMENT ($)	INDICATING IT WILL COMMIT THROUGH BIDDING PROFILE?
A	60	30	Yes
B	50	55	No
C	44	56	No
D	46	44	Yes

As can be seen, each generator has different views of the future and different thresholds for commitment. Those generators with an expectation which exceeds their threshold are indicating, through their bidding profile, that they will commit. The collective commitment decisions of market participants' indicative commitment decisions are provided to the market via the pre-dispatch process.

20 hours ahead of real time, generator D adjusts its probability weighted expectation of future spot prices downwards – perhaps in response to its own demand forecasts. Consequently, it alters its bids (in bold in the table below).

GENERATOR	INDIVIDUAL PROBABILITY-WEIGHTED EXPECTATION OF FUTURE SPOT PRICES ($)	THRESHOLD FOR COMMITMENT ($)	INDICATING IT WILL COMMIT THROUGH BIDDING PROFILE?
A	60	30	Yes
B	50	55	No
C	54	56	No
D	**43**	**44**	**No**

In response, the other generators' expectations of spot prices increase, shown in bold in the table below.

GENERATOR	INDIVIDUAL PROBABILITY-WEIGHTED EXPECTATION OF FUTURE SPOT PRICES ($)	THRESHOLD FOR COMMITMENT ($)	INDICATING IT WILL COMMIT THROUGH BIDDING PROFILE?
A	**65**	30	Yes
B	**56**	55	**Yes**
C	**55**	56	No
D	43	44	No

As a consequence, generator B structures its bids so that it will now commit (providing no other changes).

This process continues iteratively and continuously until the time at which the generators need to make their unit commitment decisions. Rebidding by generators and updates to demand forecasts by AEMO occurs frequently in the NEM.

Reserves are implicitly valued through this process. If spot prices are low, and market participants' probability-weighted expectations of future spot prices are also low, then this implies that the market has sufficient reserves.

As generators de-commit where the costs of committing are not outweighed by the expected (low) future spot prices, market participants' probability-weighted expectations of future spot prices will rise until an equilibrium is reached where an efficient level of reserves have been committed.

Conversely, if market participants' probability-weighted expectations of future spot prices are high, then market participants should commit their plant (even if spot prices are *currently* low) in order to receive those expected high spot prices or defend their contractual positions. In this case, probability-weighted expectations of future spot prices should again drop until an equilibrium is reached. Crucially, it is market participants' probability-weighted expectations of future spot prices along with a number of other factors such as their contractual position, rather than the current spot price or AEMO's pre-dispatch forecasts of spot prices (as distinct from demand), which influences their bidding behaviour.

Market participants should have strong financial incentives to make sure that they are not individually short of generation in order to meet their contractual commitments, or, if not contracted for all their capacity, in order to avoid missing the opportunity of earning revenue. The market price cap is determined with this process in mind. It is high compared to the average wholesale spot price of electricity in order to provide sufficient reward to generators to be available when they are most needed by the system (when the price is high) despite making losses in individual dispatch intervals (when the price is lower). In effect, a high market price cap serves to increase the probability-weighted expected future spot price: even if the probability of a high spot price is low, the fact that the spot price could go very high serves to provide incentives for sufficient generators to be available “just in case”.

Some commentators have suggested that the unit commitment decisions taken by individual market participants may be inefficient and that as a result, dispatch is inefficient. They suggest that instead, unit commitment decisions should be centralised and a US-style ahead market introduced. In the Commission’s analysis of ahead markets we have considered that centralised unit commitment may be justified on the basis that the system operator has a unique view of the entire system and also has better visibility on system security issues. Therefore the system operator may be best placed to maximise the efficiency of dispatch outcomes. However, our analysis as well as feedback from stakeholders has found that this is not likely to be the case. See appendix D for further details.

A further argument in favour of centralised unit commitment appears to be based on the assumption that generators bid at the cost of their fuel (i.e. not taking account of unit-commitment costs), and will therefore seek to de-commit whenever spot prices are below the cost of their fuel. However, as discussed above, generators structure their bids not simply based on the current spot price, nor solely on AEMO’s pre-dispatch forecast of prices, but on their own weighted average expectations of future price, amongst other factors such as their unit commitment costs.

The process of optimising dispatch is therefore a complex one, not solely undertaken through the NEM dispatch engine in real time, but also through the iterative process of market participants continually adjusting their expectations, as described above. While the dispatch engine only takes account of the next five minutes in determining which generators to dispatch given their bids, these bids made by market participants themselves take account of a longer term view. It is through this process that unit commitment and dispatch optimisation occurs over time. As noted above, the arguments for and against a move from the current NEM arrangements to centralised unit commitment are discussed in more detail in appendix D.

B.2.4 Other considerations

As discussed above, the incentives provided through the spot and associated contract market appear to provide incentives for efficient operational and investment decisions to provide the system sufficient dispatchable and flexible generation and load capacity for reliability purposes.

This finding is predicated on the incentives provided through the spot and contract market not being distorted.

There are a number of possible sources of distortions to the market, including:

- An inappropriately low market price cap (or other reliability settings). This would cap the rewards for dispatchable and flexible generation in the event of price spikes resulting from rapid or unexpected changes in supply and demand. An increased abundance of low short run marginal cost generation may result in a decrease in the wholesale prices that are observed most of the time during normal conditions, which in turn may require a high market price cap to allow other generators to recover their costs when price spikes occur. However, as noted above, the Reliability Panel has recently undertaken extensive analysis of these settings and concluded that there current values of the reliability settings remain appropriate.

- The relative size of generation units in comparison to regional demand. For example, in South Australia there are a number of generating units that represent a significant portion of demand. This means that in South Australia, where demand is relatively low, an individual generating unit may, by committing an entire unit, result in an excess of reserves compared to efficient levels, but by not commitment would mean that there are insufficient levels reserves provided to the system. This inability to "fine-tune" commitment may mean that market participants, acting on their own incentives, provide insufficient reserves.
- Interventions by the system operator in the wholesale market for reliability reasons. As discussed in chapter 6, interventions are an appropriate last-resort mechanism to maintain reliability. However, the actual or prospective changes to financial outcomes for market participants as a consequence of intervention may serve to distort the price signals provided by the spot and contract market. This may in turn lead to inefficient operational or investment decisions. As a result, intervention mechanisms need to be designed to minimise distortionary effects.
- Interventions by the system operator in the wholesale market for system security reasons, which could have similar effects to interventions in the market for reliability reasons.
- Uncertainty regarding emissions reduction policy, which in turn influences the market participants' expectations for the future need for dispatchable and flexible generation/load. As noted above, proposed National Energy Guarantee should provide policy certainty regarding an emissions reduction mechanism that is effectively integrated with the electricity market.
- Prospective investors in new generation may also be disconcerted by the increasing role of the state and Commonwealth governments in funding, subsidising or studying the feasibility of additional dispatchable generation capacity. Private investors may be less inclined to invest in new generation for fear that their returns could subsequently be truncated by government-sponsored initiatives.
- Insufficient levels of competition in the wholesale market. The final report of the ACCC's Retail Electricity Pricing Inquiry notes that market concentration in the NEM has increased and expresses concern that this would be significantly affecting bidding behaviour in the NEM, which could lead to prices above efficient levels. [387] The report also makes a number of recommendations to deal with market concentration and boost competition in generation and retail markets.[388]

387 ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018.

388 Ibid.

As noted above, there are programs of work currently being undertaken to address these considerations, with the intent of reducing the prospect of distortions impacting price signals for dispatchability and flexibility.

This includes the work currently being undertaken by AEMO in identifying and exploring the issues that it is observing in South Australia. For example, AEMO has observed that the lack of a current price signal in South Australia for system strength may not incentivise generators to commit when needed. AEMO's work is summarised in chapter 5.

B.2.5 Conclusions

In theory, the spot and contract market appears to provide incentives for the efficient provision by market participants of dispatchable and flexible generation and load, in operational and investment timescales.

However, factors outside of the spot and contract market both inside and outside of reliability frameworks may distort these incentives. Steps are being taken both as part of the AEMC's reliability program and outside of it to limit these distortionary effects.

In particular, AEMO and the AEMC will continue to work together to progress consideration of issues being observed in the South Australian market.

B.3 Quantitative analysis of ramp-rate data

The Commission has undertaken initial quantitative analysis to examine whether the above theoretical conclusions appear to bear out in reality.

While the concepts of dispatchability and flexibility are not expressly defined or measured in the NEM, the related concept of ramping is. The Commission has therefore investigated ramping data as a proxy as to whether dispatchability and flexibility are valued in the NEM.

This section sets out a quantitative analysis of ramp-rate data, and is structured as follows:

- **Understanding ramp-rate data:** the first step is to describe the meaning of ramp-rates and ramp-rate constraints. The intention is provide some intuition about ramp rates by examining how frequently ramp rate constraints bind across the NEM by generating unit.
- **Historical demand for ramping:** the next step is to consider the historical demand for ramping across the NEM, over time-scales of 5-minutes and 3-hours.
- **Historical availability of ramping:** having considered demand for ramping, the next step is to look at the supply of ramping – i.e., the degree to which ramping has been available in the NEM.
- **Relationship between ramping and price:** the final step is to examine whether there is a relationship between demand for ramping and price outcomes.

There is some evidence that the increase in renewable penetration is leading to an increase in the demand for ramping at the extremes. In terms of supply, there appears to be an abundance of ramping capacity available to come online within a period of up to half an hour in regions of high renewable penetration. In contrast, there appear to be times in South

Australia where the region has very low quantities of spinning reserve, and so may not be well-placed to respond to rapid, unpredictable ramping requirements, i.e., within a period of five minutes.

Analysis also shows that high demand for ramping (on a 5-minute basis) in South Australia is associated with high wholesale prices. These outcomes are driven by the off-peak hot water load that occurs late at night, and is a phenomenon that has been present in the market for a long time. These outcomes demonstrate that the market is currently providing price signals for ramping, and that these price signals have supported the adequate supply of ramping for many years.

We have focussed our analysis on historical outcomes. We have not attempted to predict future outcomes, but we consider our analysis to be relevant to future outcomes. This is since the analysis that currently there is surplus ramping capacity (i.e. ramping capacity is excess of what is demanded) that currently exists in the market and so we would expect this to continue for several years in the future.

In the time available it has not been feasible to complete an exhaustive study of all available data. Notwithstanding, the analysis is intended to be as comprehensive as possible in the time available to complete the study.

We also note that AEMO has recently projected future ramp-rate requirements for the NEM over the one-hour and three-hour timeframes over the next 20 years. AEMO forecasts that ramp rates are projected to almost double from 2017 to 2025 over the one-hour and three-hour timeframes.[389] The AEMC will continue to work with AEMO to identify future issues with flexibility in the system.

B.3.1 Understanding ramp-rates and ramp-rate data

Ramping is defined as the ability of a unit to alter its output,[390] either up or down. For the purposes of this section:

- the ability of a unit to *increase* its output is its ability to 'ramp-up'
- the ability of a unit to *decrease* its output is its ability to 'ramp-down'.

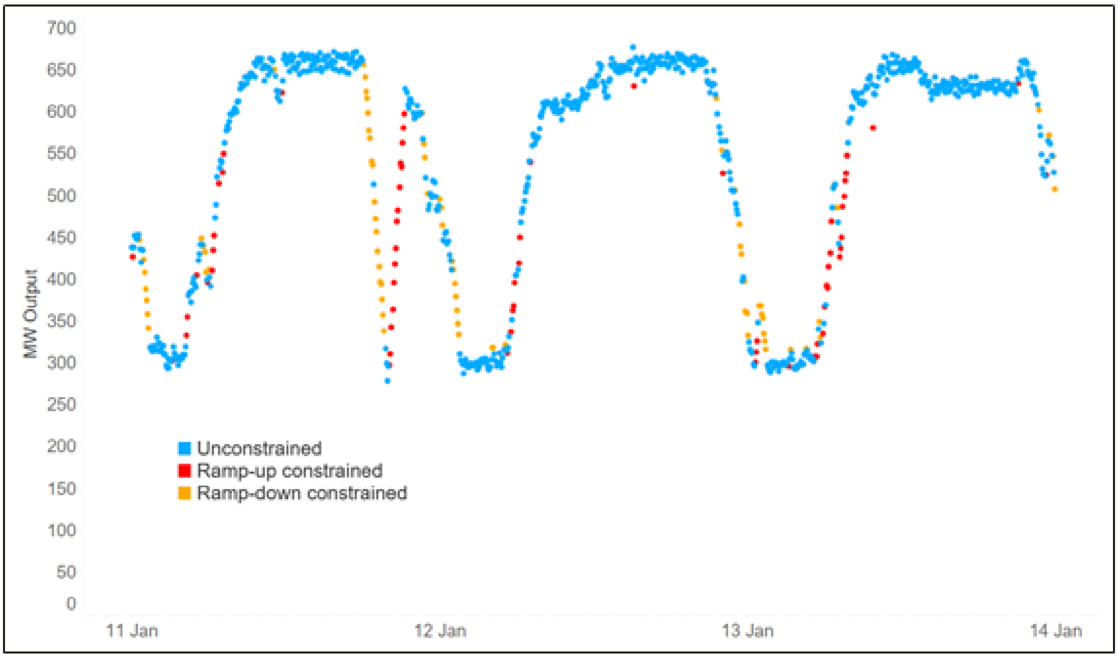
When a unit is operating at its maximum ramp-up rate it is said to be *ramp-up constrained*. Similarly, when a unit is operating at its maximum ramp-down rate, it is *ramp-down constrained*. Figure 1 provides an illustration of a unit that experiences periods when it is ramp-rate constrained. The chart shows the output of Bayswater 1 on a 5-minute interval basis from 11 to 13 January 2017. Each dot represents a single dispatch interval. Periods when the unit is unconstrained are shown in blue; periods when the unit is ramp-up constrained are shown in red; and periods when the unit is ramp-down constrained are shown in yellow. Bayswater is a coal-fired power station with a high capacity factor (i.e., a

389 AEMO, *Integrated System Plan 2018*, July 2018, p. 65.

390 In the case of load, ramping is the ability of the unit to alter its load. In this analysis, we have focussed on the ability of supply (ie, generators) to ramp.

baseload plant). However, the plant is often marginal in New South Wales, and so it often follows the load in the region as shown in Figure B.1.

Figure B.1: Illustration of ramp-rates

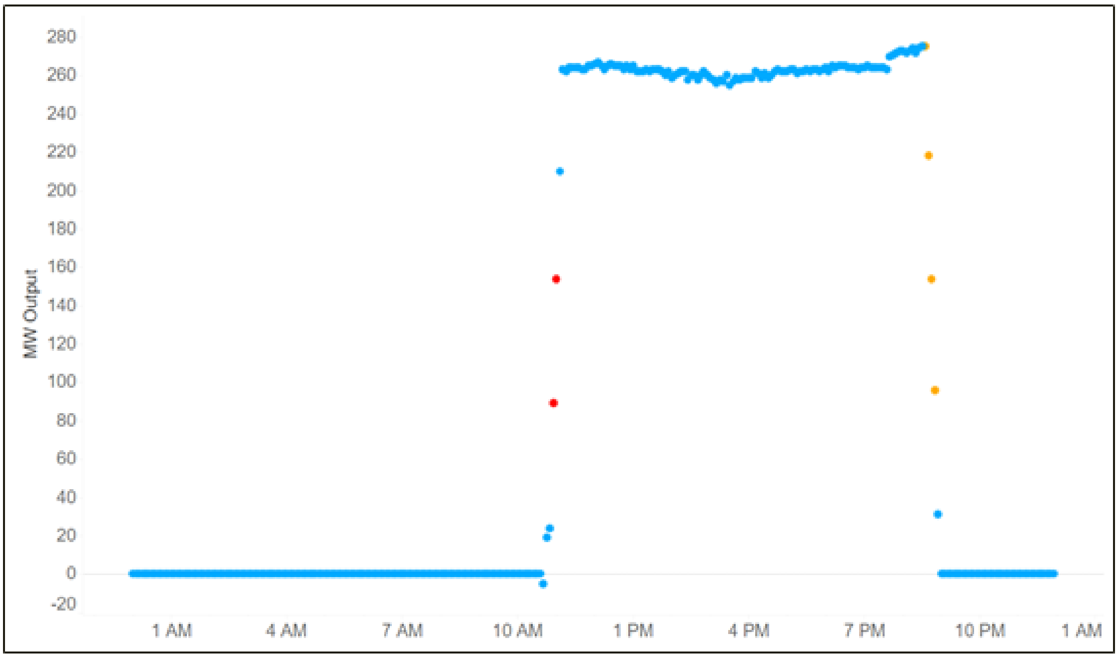


Source: AEMC analysis of MMS data.

When the unit is increasing its output, it often reaches a level where it is ramp-up constrained. At these times, the limitations on the unit's ability to ramp-up influence its output. Similarly, during periods when the unit is decreasing its output, it often reaches a level where it is ramp-down constrained.

The ramp-rate limits differ depending on the unit in question. Figure B.2 shows the output of Mortlake 1 on 27 January 2017. Mortlake is a peaking plant, designed to turn on rapidly to meet short-term spikes in demand. Again, the unit is ramp-rate constrained as it turns on, and off. However, the unit has greater ability to ramp-up and down, and so the ramp-rate constraints bind for only two to three intervals in succession.

Figure B.2: Illustration of ramp-rates, MORTLK1 output, 27 January 2017



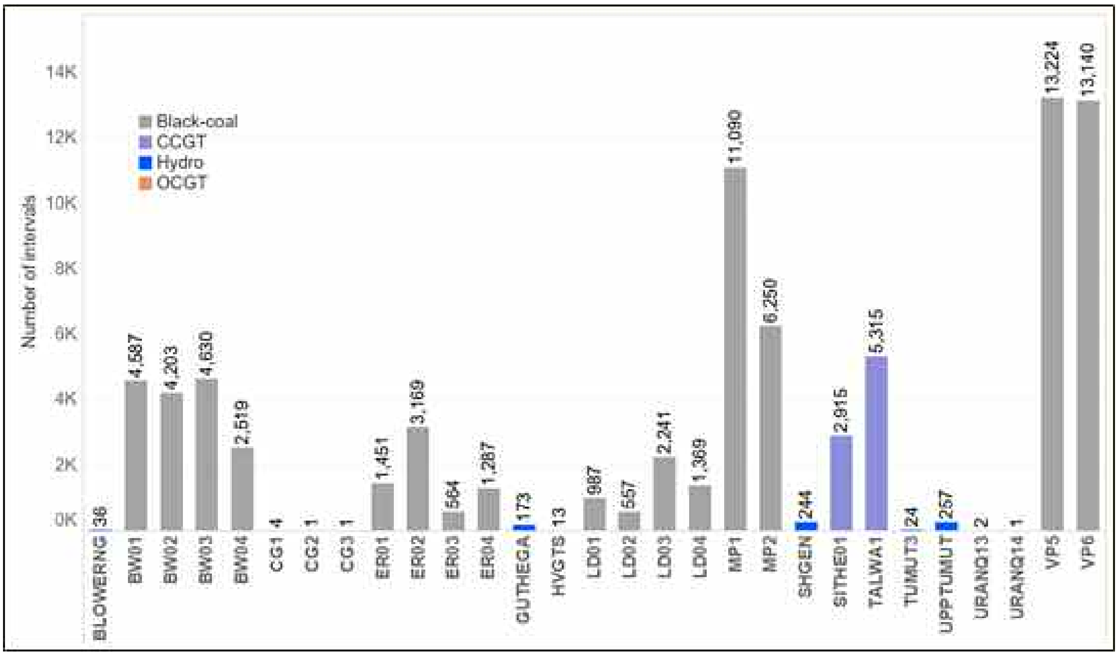
Source: AEMC analysis of MMS data.

Ramp rates bind to differing degrees across the generation fleet, with the extent of binding being a function of the unit's physical characteristics and operational profile.

Figure B.3 shows the frequency with which units in New South Wales were ramp-up constrained in 2017. The lengths of the bars represent the number of dispatch intervals for which each unit was ramp-up constrained. Noting that there are 105,120 dispatch intervals in a year, we can see that some units (i.e., Vales Point 5 and 6) were constrained for around 12 to 13 per cent of the time. In contrast, other units (e.g., Eraring 1 and 4) were constrained for only 1 to 1.5 per cent of the time. These differences reflect the operational profile of each plant – Vales Point and Bayswater are typically load-following, and so are regularly changing their output levels. It follows that these plants are more frequently ramp-rate constrained than other coal-fired units, such as those of Eraring, which typically operate at or near full capacity.

It is important to note that more flexible plant tend to operate less frequently, and so are ramp-rate constrained for fewer intervals each year. For example, Colongra may only turn on for a few hours per year, and so it is unsurprising that it is ramp-up constrained for so few intervals.

Figure B.3: Frequency of units being ramp-up constrained, NSW 2017



Source: AEMC analysis of MMS data.

This analysis shows that, like any constraint, ramp-rate constraints can and do bind. At any point in time, it is highly likely that there is a ramp-rate constraint binding somewhere in the NEM. Some units, such as those that follow the load, are regularly ramp-rate constrained. Others that run consistently at high capacity factors may only rarely be ramp-rate constrained.

B.3.2 Historical demand for ramping

What is the *demand* for ramping capacity across the NEM? Put another way, how much ramping capacity is even needed?

Specifically, an important question is whether the entry of renewable generation (i.e., wind, large-scale solar, and rooftop solar PV) has been associated with an increased demand for ramping in the NEM. Of particular interest are extreme ramping outcomes, i.e., the periods in each year where the demand for ramping reaches its highest levels.

This analysis focusses on changes in 'demand for scheduled generation' which is defined as follows:

Demand for Scheduled Generation= Total Demand + Non-Scheduled Generation - Wind - Large scale solar

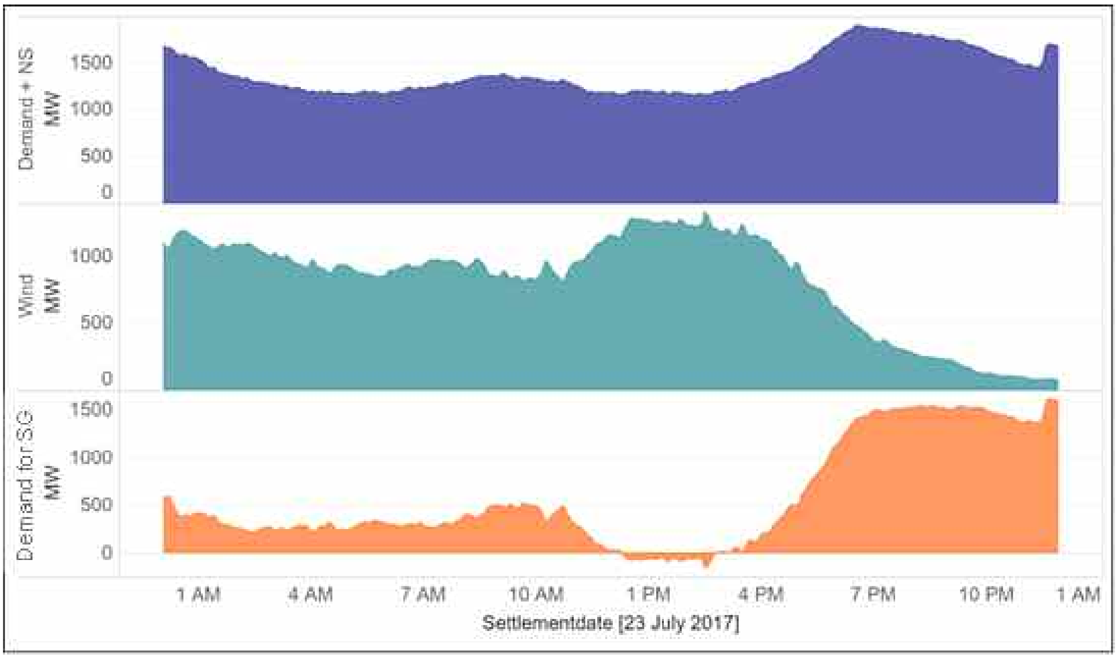
Figure B.4 illustrates the calculation of demand for scheduled generation in three steps:

- The top panel shows the level of demand plus non-scheduled generation (shown in blue) in South Australia.
- The centre panel shows the level of wind output in South Australia (shown in green).
- The bottom panel shows the demand for scheduled generation (SG - shown in orange), given by the blue minus the green areas.

Note that there is no large scale solar in South Australia.

The resulting level of demand for SG differs greatly from the original demand profile. This example, for 23 July 2017 in South Australia, has been cited by AEMO as an example of an instance where there has been considerable demand for ramping between 4pm and 7pm, corresponding to a decline in wind output and an increase in demand and non-scheduled generation.[391]

Figure B.4: Illustration of calculation of demand for SG, 23 July 2017, SA



Source: AEMC analysis of MMS data.

This analysis examines the changes in demand for scheduled generation over two time-scales: 5-minutes and 3 hours. These two time-scales allow us to consider both dynamic (5-minute) and sustained (3-hour) demand for ramping.

Demand for ramping - 3-hour time scale

This analysis of demand for ramping over a 3-hour time-scale focusses on the change in demand for scheduled generation over a 3-hour period, hereafter termed 'demand for

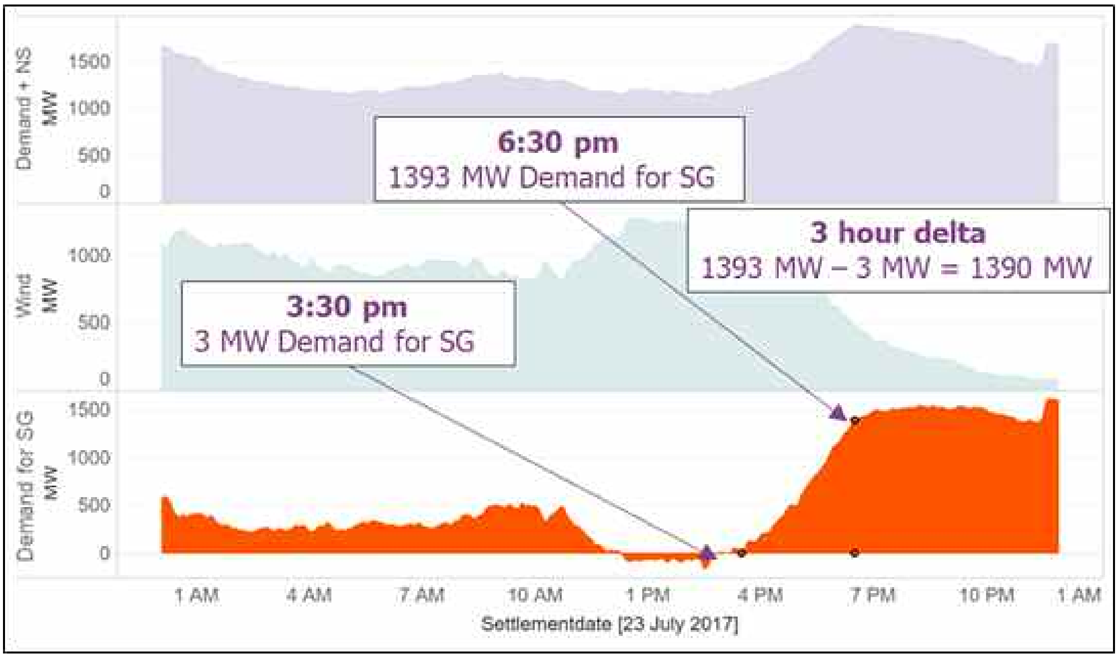
391 AEMO, submission to directions paper.

scheduled generation (3-hour delta)'. Figure B.5 illustrates the calculation of this variable for the 23 July 2017 example. It can be seen that:

- at 6:30 pm, the demand for scheduled generation was 1393 MW
- at 3:30 pm, the demand for scheduled generation was 3 MW, and so
- the 3-hour delta was 1393 MW – 3 MW= 1390 MW.

This was the maximum value of demand for scheduled generation (3-hour delta) observed on the day in question.

Figure B.5: Illustration of calculation for scheduled generation (3-hour delta), 23 July 2017, SA

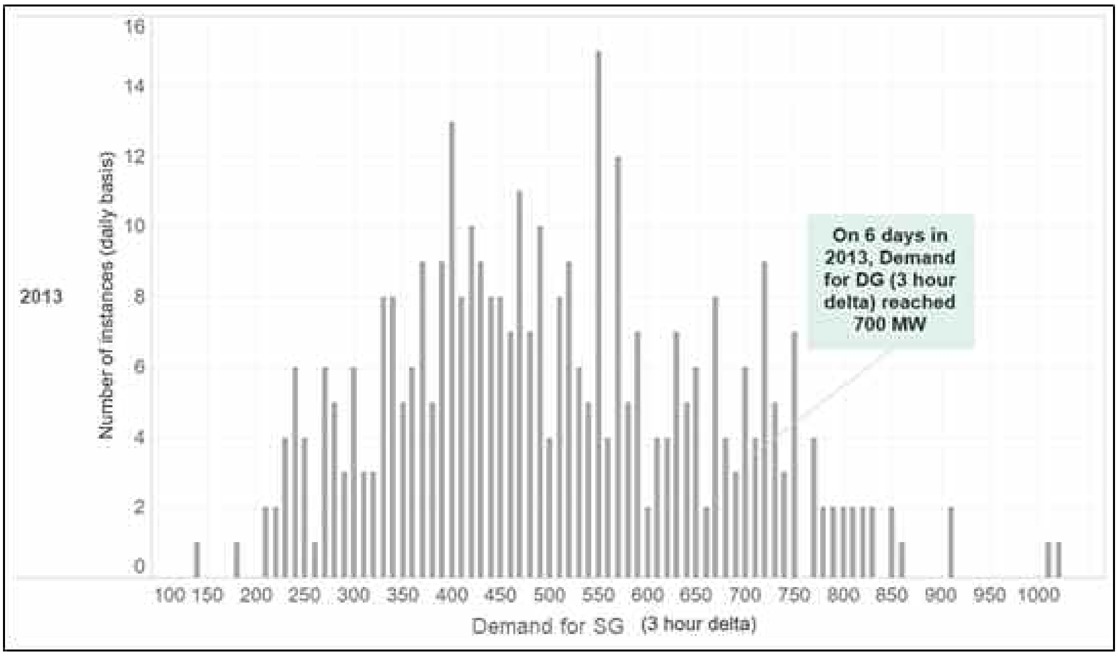


Source: AEMC analysis of MMS data.

It is useful to consider the distribution of the daily maximum demand for scheduled generation (3 hour delta). In the interests of brevity, our analysis considers the outcomes in two regions: South Australia and Victoria – both have relatively high penetrations of wind and/or small-scale solar PV.

Figure B.6 shows the distribution in South Australia for a single year. By way of explanation, the point marked on the graph at 700 MW should be interpreted as meaning that, in 2013, there were 6 days where demand for scheduled generation (3-hour delta) reached 700 MW.

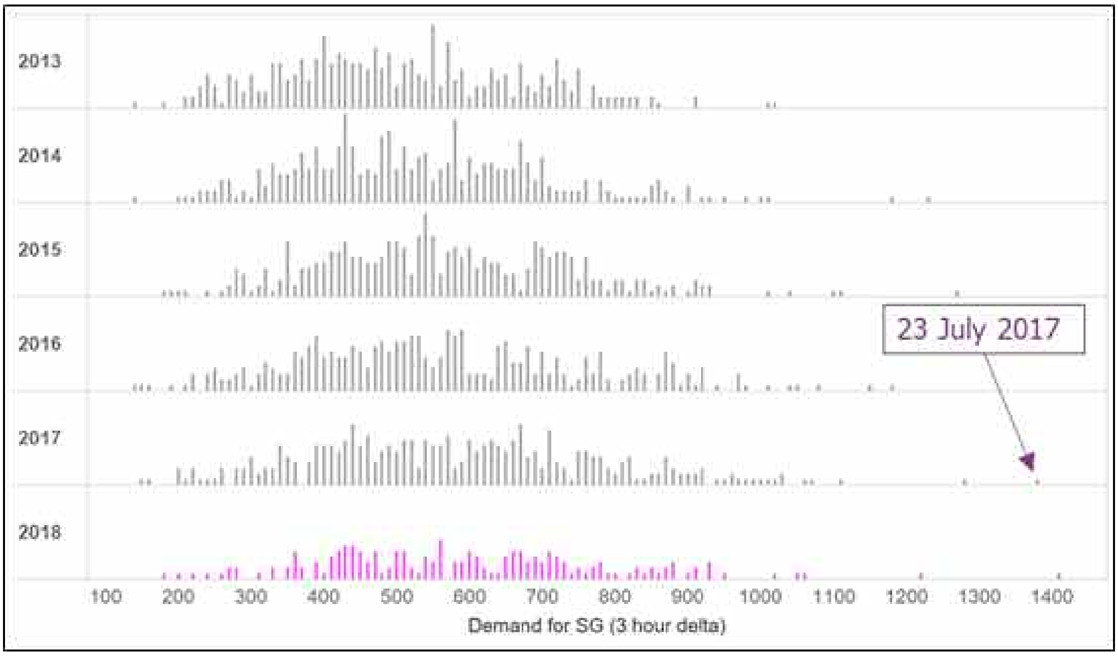
Figure B.6: Distribution of daily maximum demand for scheduled generation (3-hour delta), 2013, SA



Source: AEMC analysis of MMS data.

The Commission has analysed how this distribution has changed over time. Figure B.7 shows the same analysis as Figure B.6, but for multiple years from 2013 to 2018, with 2018 highlighted in pink. In each year, there are extreme events that lie a long way from the rest of the observations. The right-most observation in 2017 is the 23 July 2017 outcome, which we have already used as an example.

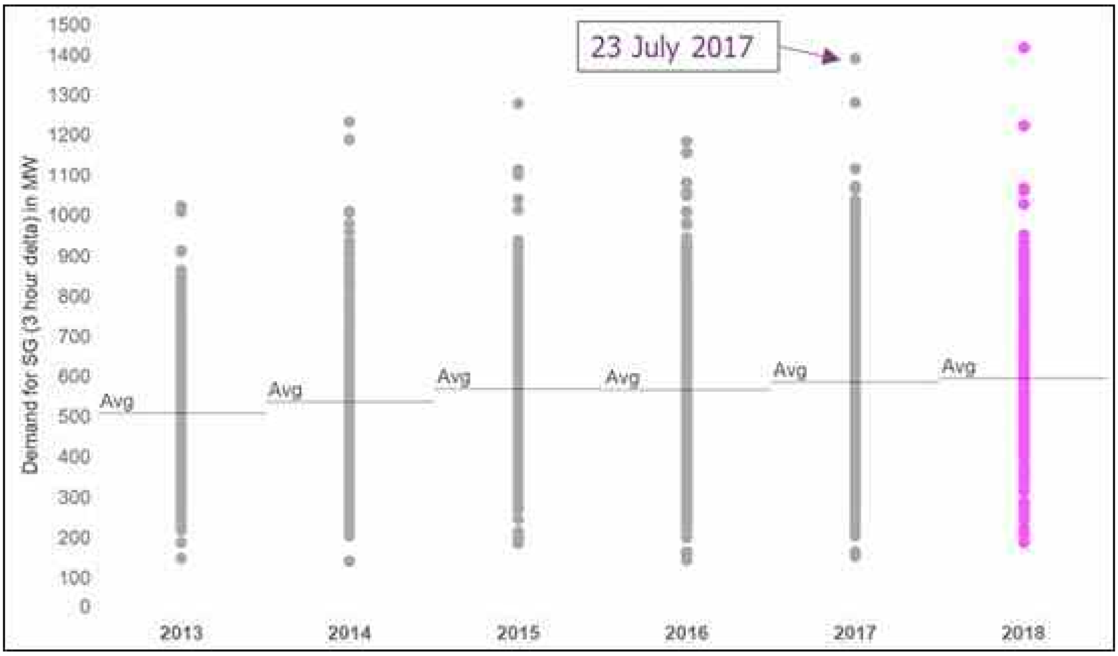
Figure B.7: Distribution of daily max. demand for scheduled generation (3-hour delta), 2013 to 2018, SA



Source: AEMC analysis of MMS data.

Figure B.8 shows another visualisation of the same data, which shows that average level in each year has been increasing gradually over time.

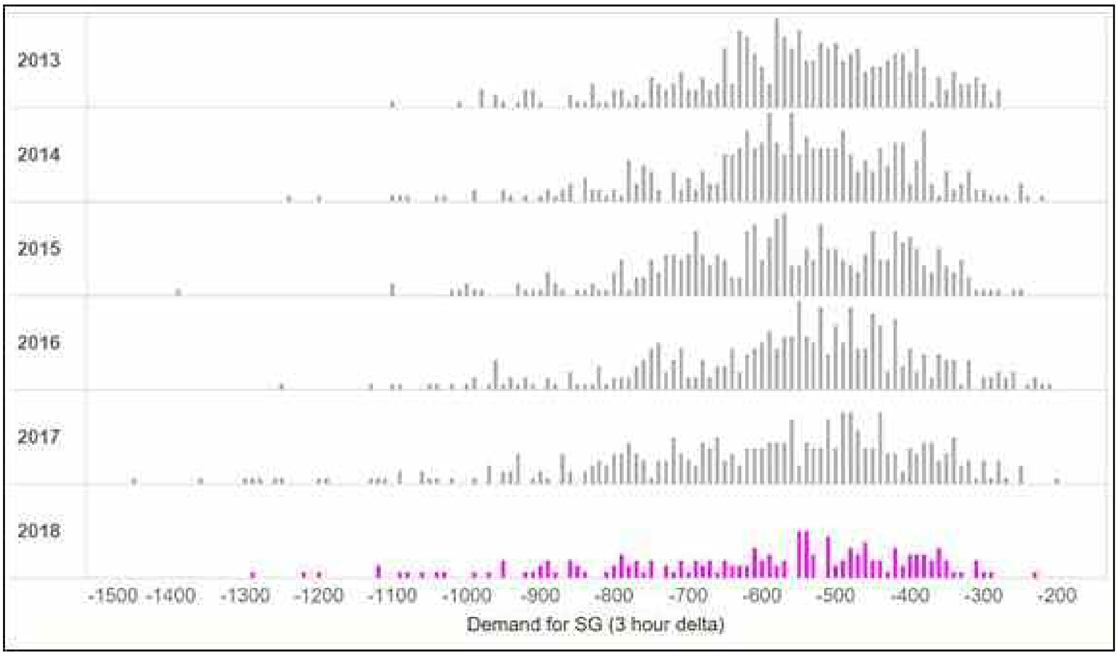
Figure B.8: Distribution of daily max. demand for scheduled generation (3-hour delta), 2013 to 2018, SA



Source: AEMC analysis of MMS data.

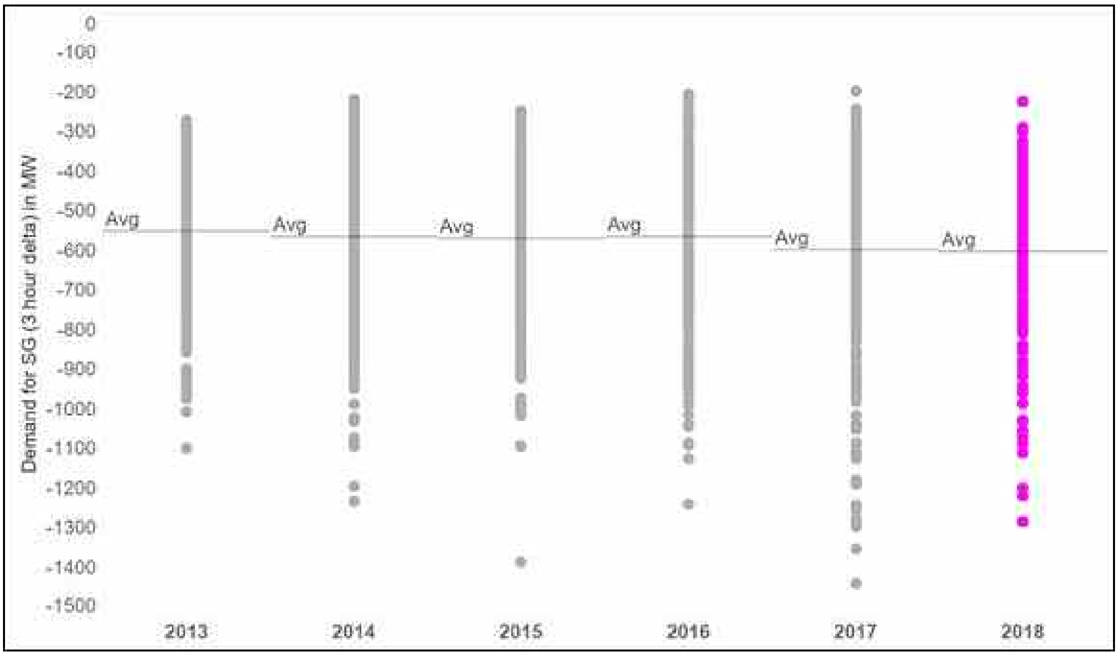
Figures B.9 and B.10 show the distribution of daily maximum negative demand for scheduled generation (3-hour delta) for 2013 to 2018 in South Australia. Historically, there has been a trend of decreasing average demand for ramping-down in South Australia, and more extreme values have been observed in 2017 and 2018.

Figure B.9: Distribution of daily maximum negative demand for scheduled generation (3-hour delta), 2013 to 2018, SA



Source: AEMC analysis of MMS data.

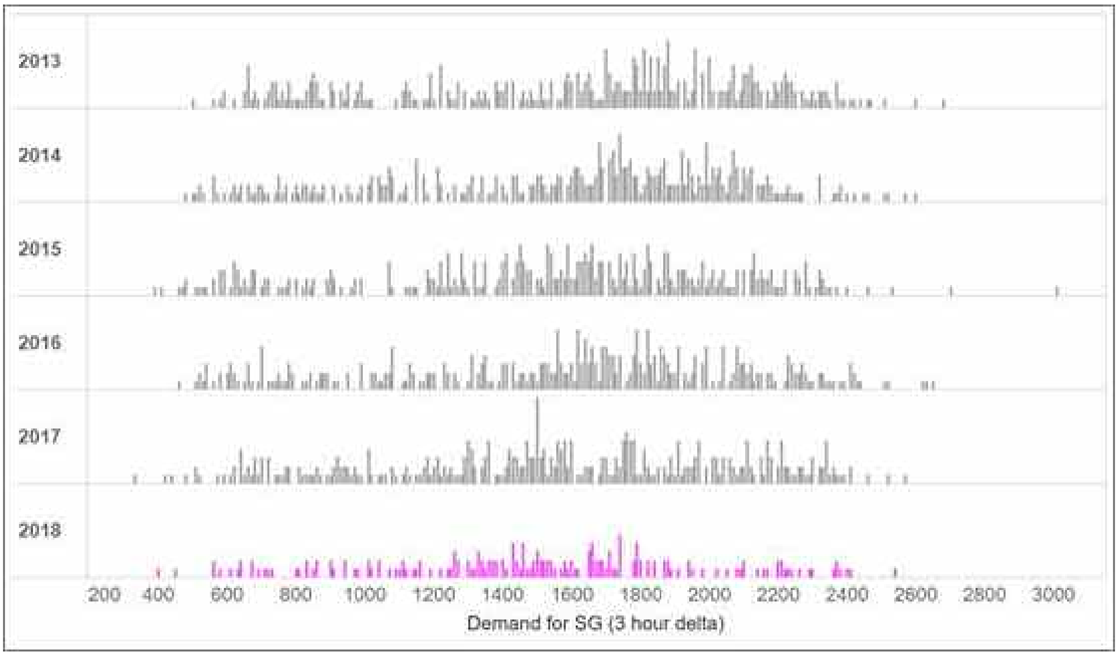
Figure B.10: Distribution of daily minimum demand for scheduled generation (3-hour delta), 2013 to 2018, SA



Source: AEMC analysis of MMS data.

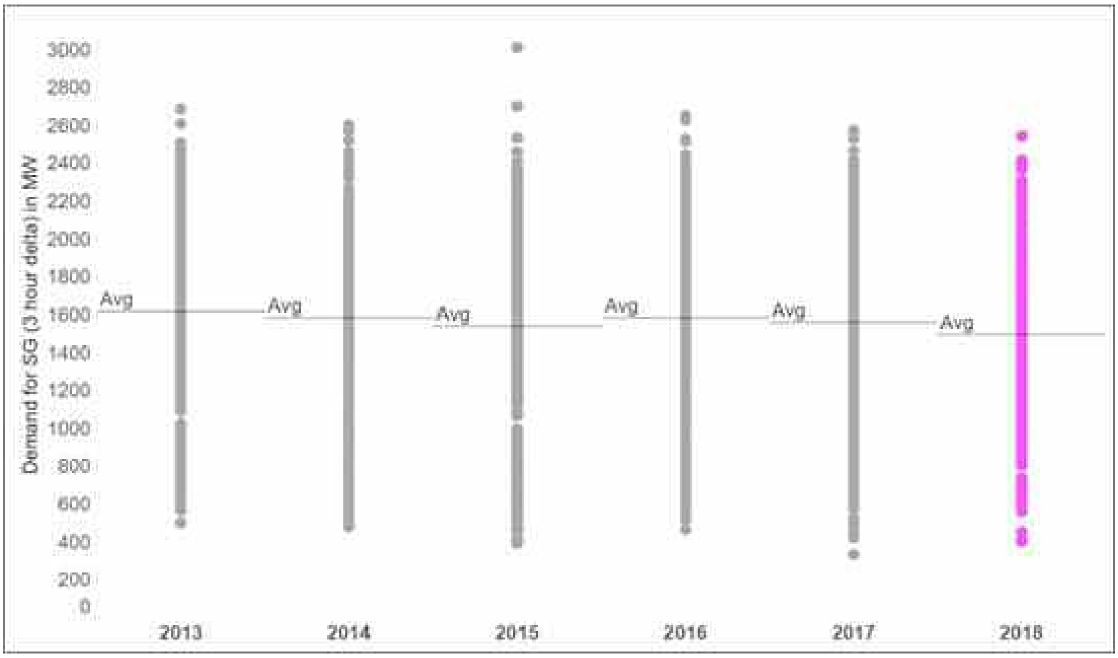
In addition to South Australia, we have also examined outcomes in Victoria. Figures B.11 and B.12 show the distribution of daily maximum demand for SG (3-hour delta) from 2013 to 2018 in Victoria. These charts show that there has been no increase in either the average or extreme values of this distribution from 2013 to 2018.

Figure B.11: Distribution of daily max. demand for scheduled generation (3-hour delta), 2013 to 2018, Vic



Source: AEMC analysis of MMS data.

Figure B.12: Distribution of daily maximum demand for scheduled generation (3-hour delta), 2013 to 2018, Vic



Source: AEMC analysis of MMS data.

A similar analysis of demand for ramping down (not shown) shows that the average value of the daily minimum demand for scheduled generation (3-hour delta) has decreased slightly since 2013.

In summary:

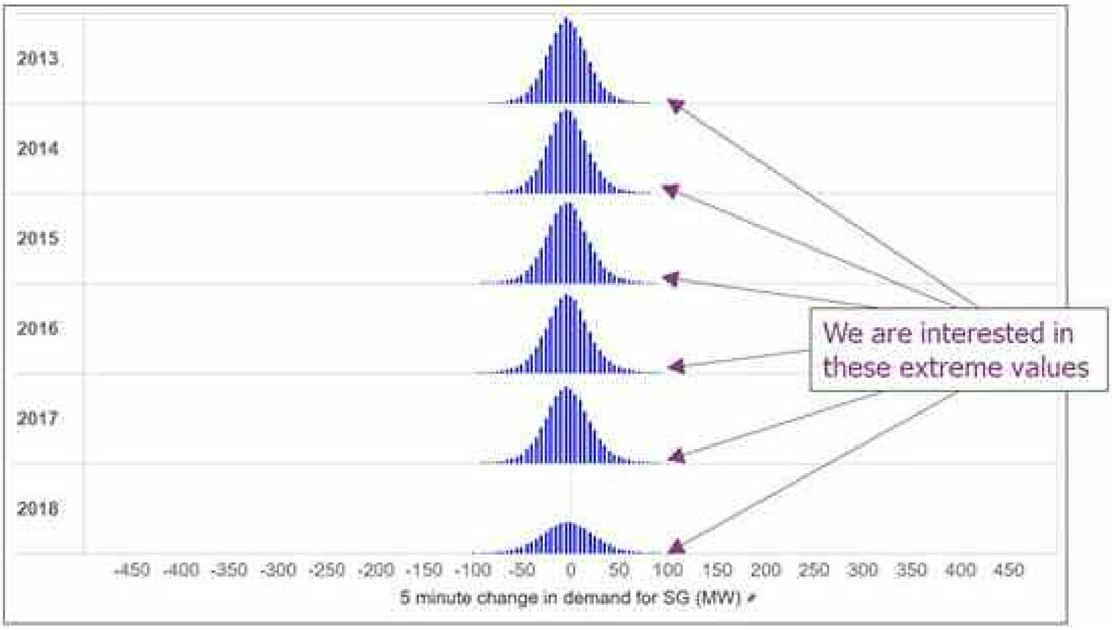
- There appears to be some evidence that there has been an increase in the extreme values of demand for ramping-up (on a 3-hour basis) in South Australia. Nevertheless, this outcome is driven by outcomes on just two days, i.e., 12 June 2018 and 23 July 2017.
- There has been no increase in the extreme values of demand for ramping-up (on a 3-hour basis) in Victoria since 2013.
- Since 2013 demand for ramping-down has increased in South Australia, but not Victoria.

Demand for ramping - 5 minute time scale

For our analysis of demand for ramping over a 5-minute time-scale, we have simply calculated the change in demand for scheduled generation from one 5-minute interval to the next. In the time available, this analysis has only been completed for the region of South Australia.

Figure B.13 shows the distribution of 5-minute changes in demand from 2013 to 2018 in South Australia. The distributions are extremely similar from one year to the next. But of interest are the changes in the extreme values (i.e., at points where the changes exceed 100 MW from one interval to the next).

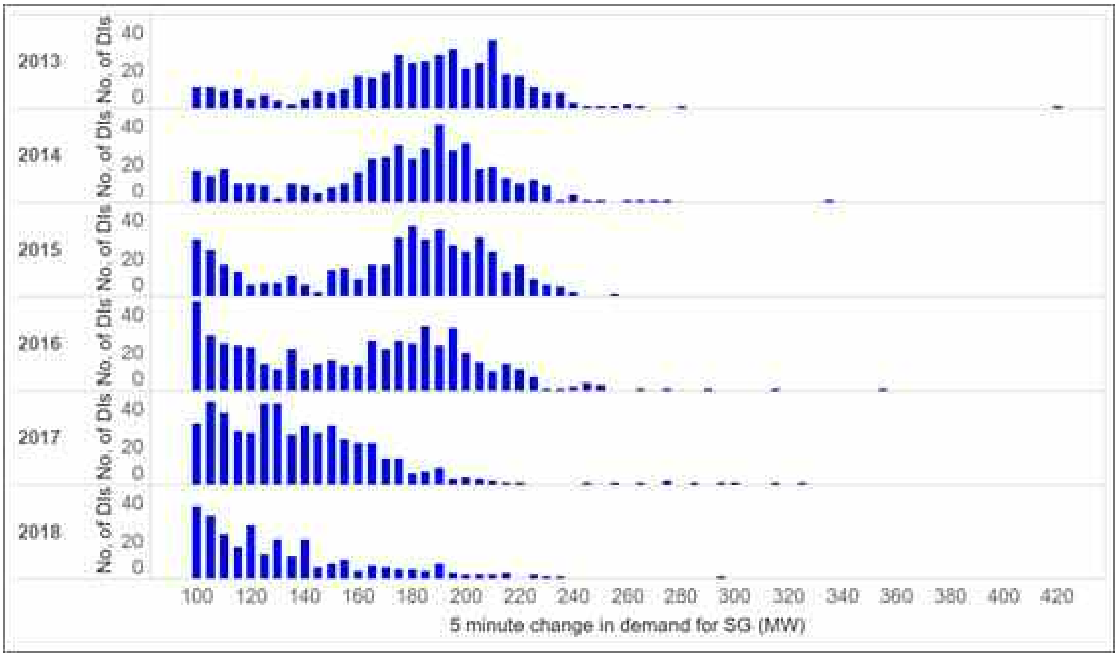
Figure B.13: Distribution of 5-minute change in demand, 2013 to 2018, South Australia



Source: AEMC analysis of MMS data.

Figure B.14 focuses on those instances where there was a demand for ramping-up of more than 100 MW. This tail of the distribution has been relatively constant from 2013 to 2016, and the values observed in 2017 and 2018 have tended to be less extreme.

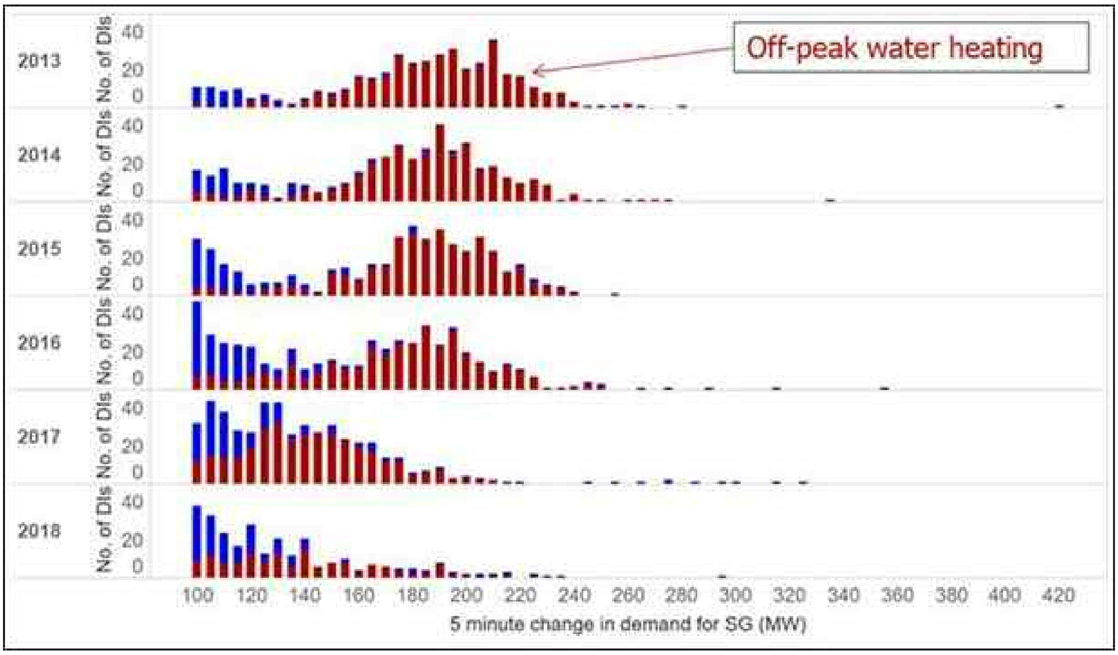
Figure B.14: Distribution of 5-minute change in scheduled generation demand > 100MW, 2013 to 2018, SA



Source: AEMC analysis of MMS data.

It is helpful to consider the drivers of these extreme outcomes. Figure B.15 highlights those observations that occurred in the dispatch intervals between 11:30 pm and midnight, and shows that the vast majority of these high ramp-up events occurred at this time. This is the time at which the South Australia off-peak water heating load comes online.

Figure B.15: Distribution of 5-minute change in demand for scheduled generation > 100 MW highlighting off-peak hot water start times, 2013 to 2018, SA

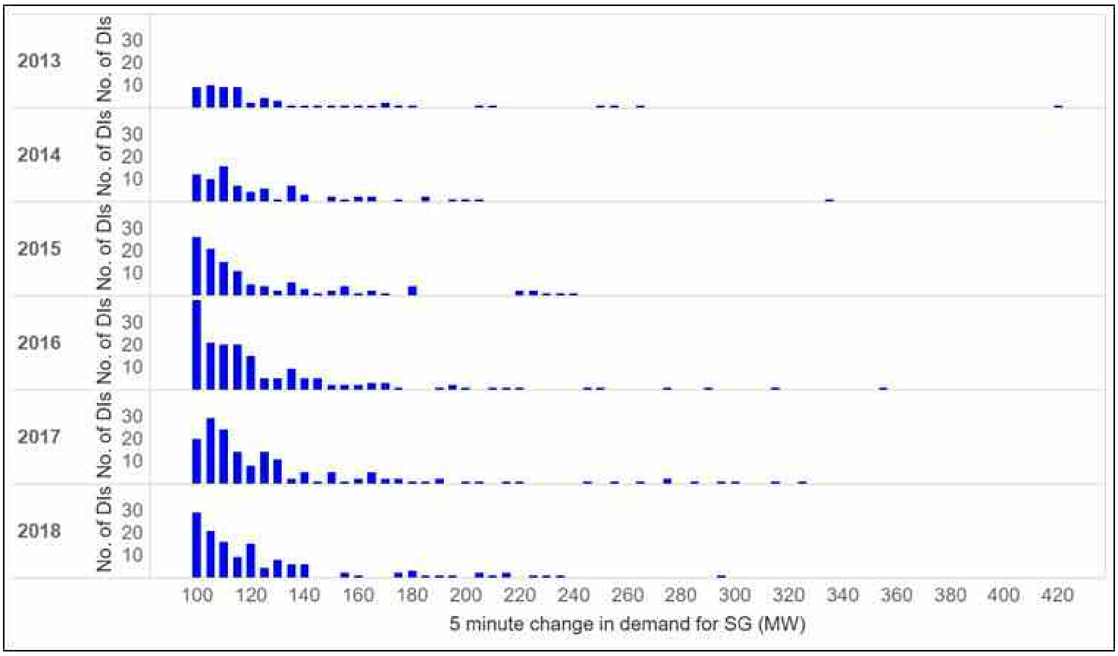


Source: AEMC analysis of MMS data.

These results are inconsistent with a narrative that increased penetration of renewables is driving higher levels of ramping (on a 5-minute interval basis). On a 5-minute interval basis, the principal driver of ramping appears to be one that has been around for the better part of a decade i.e. off-peak hot water loads.

However, there been an increase in demand for ramping excluding these observations related to off-peak water heating, as shown in Figure B.16. Given that off-peak water heating ramping events are predictable, the figure therefore shows ramping events that typically mat not be predictable. As a result, AEMO has recommended that we consider these observations separately, because they point to a trend of increasing frequency of unpredictable high ramping demand events.

Figure B.16: Distribution of 5-minute change in demand for scheduled generation > 100 MW excluding off-peak hot water observations, 2013 to 2018, South Australia



Source: AEMC analysis of MMS data.

B.3.3 Historical availability of ramping

The next consideration is the supply, or availability, of ramping in the NEM. In line with our analysis of demand for ramping, we have examined the supply of ramping in South Australia and Victoria. In the time available, we have restricted our analysis to ramping up.

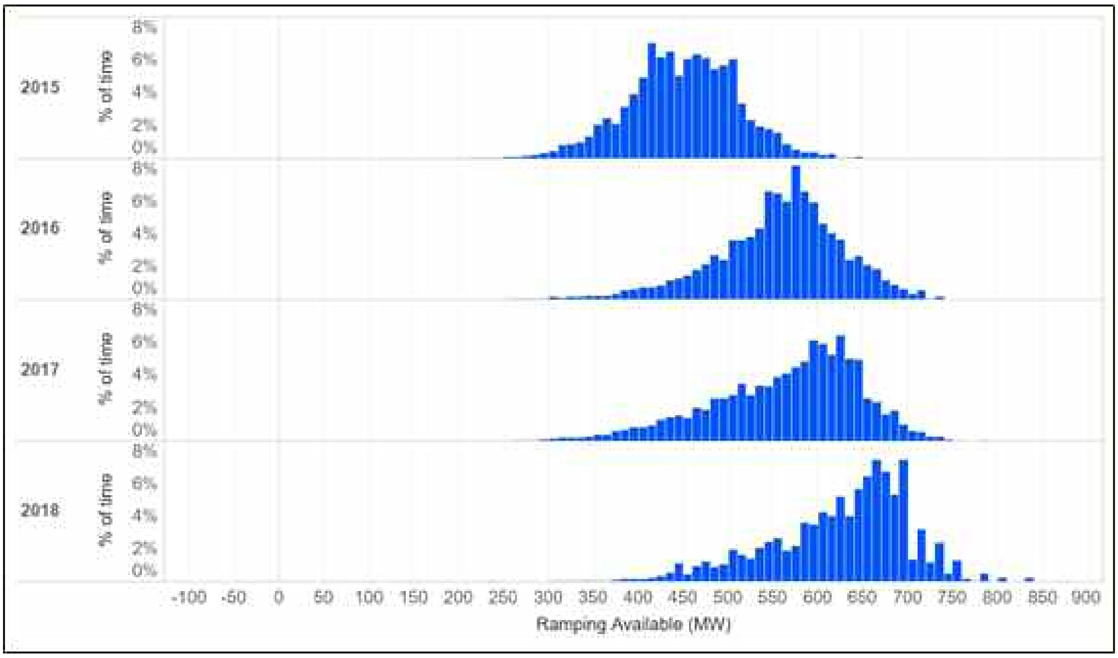
We have calculated the available ramping-up capacity of each unit using the following formula:

Available Ramping Up Capacity = min (Unit Ramp Limit, Availability - InitialMW)

The available ramping-up capacity for a region is given by the sum of the available ramping capacities of all the units in that region. We have calculated the available ramping-up capacity for each region on a 5-minute interval basis over the period from 1 January 2015 to 31 May 2018. Our analysis treats the region as being isolated – no allowance has been made for ramping that can be provided from other regions via interconnectors. In this respect, the results will tend to underestimate the ramping available to a region. At the same time, we have included *all* generation bid as available – even from fast-start units that may not be online. In this respect, our results will tend to produce a higher estimate of the ramping available to a region.

Figure B.17 shows the distribution of available ramping-up capacity in South Australia from January 2015 to May 2018. The spread of the distribution shows that there is considerable variability in the ramping available at any one point in time. The results suggest that 5-minute ramping capacity has increased over the last four years. This is inconsistent with a narrative of a growing shortage of ramping capacity in the region.

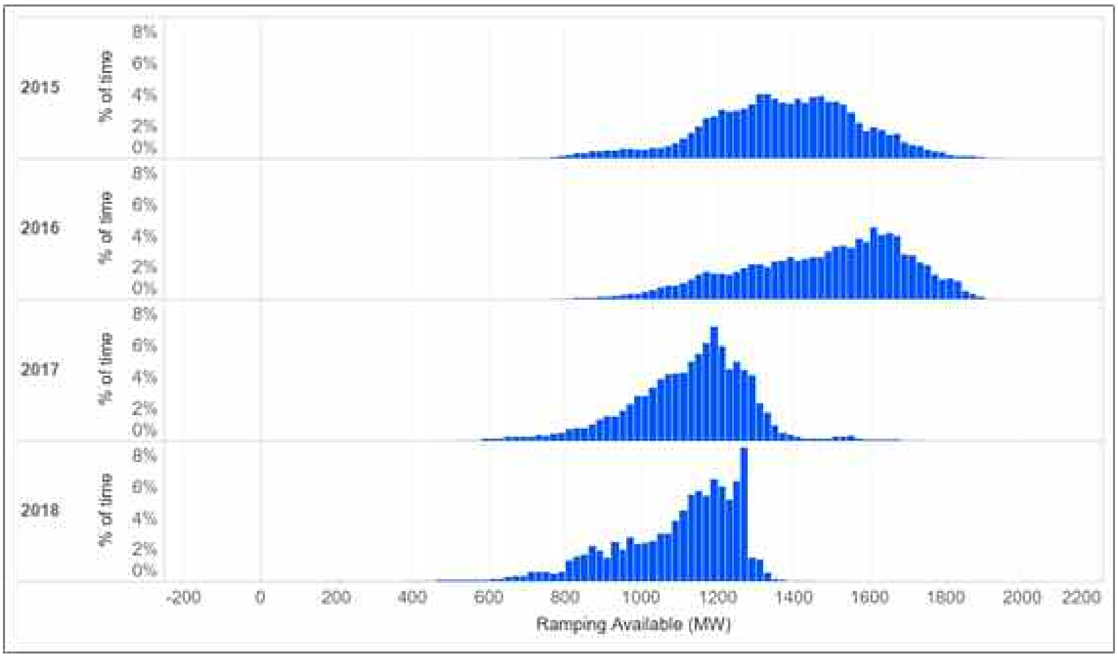
Figure B.17: Distribution of available ramping-up capacity, 5-minute interval basis, January 2015 to May 2018, South Australia



Source: AEMC analysis of MMS data.

Figure B.18 shows the same analysis for Victoria. Victoria appears to have less ramping capacity available now than in 2015. The decline in ramping availability appears to coincide with the closure of Hazelwood in 2017. Following the closure, ramping availability has decreased with other plant (e.g., Mortlake) operating at higher levels and so providing less ramping. Victoria is also making greater use of interconnectors, and so fewer units in the region are generating than prior to the closure. Fewer units will tend to mean that less ramping capacity is available.

Figure B.18: Distribution of available ramping-up capacity, 5-minute interval basis, January 2015 to May 2018, Victoria



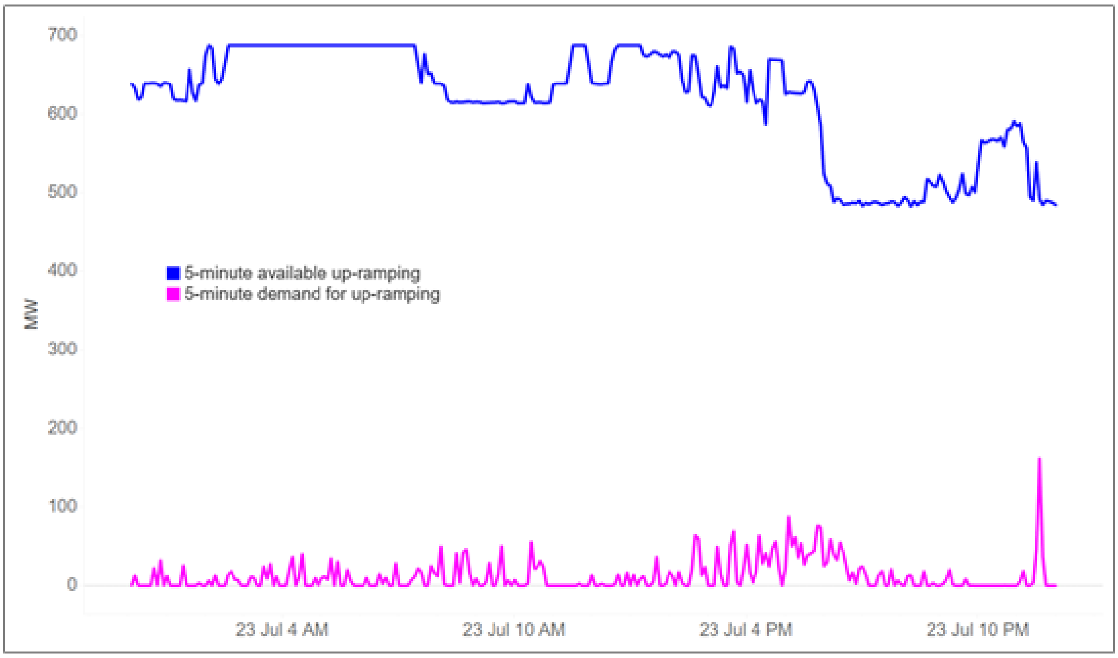
Source: AEMC analysis of MMS data.

The results for both South Australia and Victoria show that large amounts of generation[392] are available to come online (i.e., minima of 300 MW in South Australia and around 500 MW in Victoria) relative to the maximum 3-hour ramping demand (i.e., 1390 MW in South Australia and 3000 MW in Victoria). These results imply that the amount of generation that can come online in 30 minutes (i.e., 5 minute ramp-rate multiplied by 6 – noting that it may not be possible for some units to ramp at such a sustained rate for so many intervals) is more than adequate to meet 3-hour ramping demand.

As an illustration, we consider the outcomes on 23 July 2017. Figure B.19 compares the available ramping-up on a 5-minute basis (shown in blue) versus the 5-minute demand for ramping-up (shown in pink). There was clearly ample ramping capacity on this day to meet the 3-hour ramp seen in the late afternoon.

392 We have included all generation bid as available – even from fast-start units that may not be online. In this respect, our results will tend to produce a higher estimate of the ramping available to a region.

Figure B.19: 5-minute demand for ramping-up versus 5-minute available ramping-up, 23 July 2017



Source: AEMC analysis of MMS data.

Note also the high spike in five minute change in demand at 11.35 pm, corresponding to the off-peak water heating load hot water, which is far in excess of the 5-minute change in demand throughout the course of afternoon ramp.

AEMO has recommended that this analysis should be adjusted to include only ramping capacity available from units that are online, i.e., the spinning reserve that is available in the region. The rationale for this assumption is that many fast-start units may be bid as available but may take between five and 30 minutes to come online.

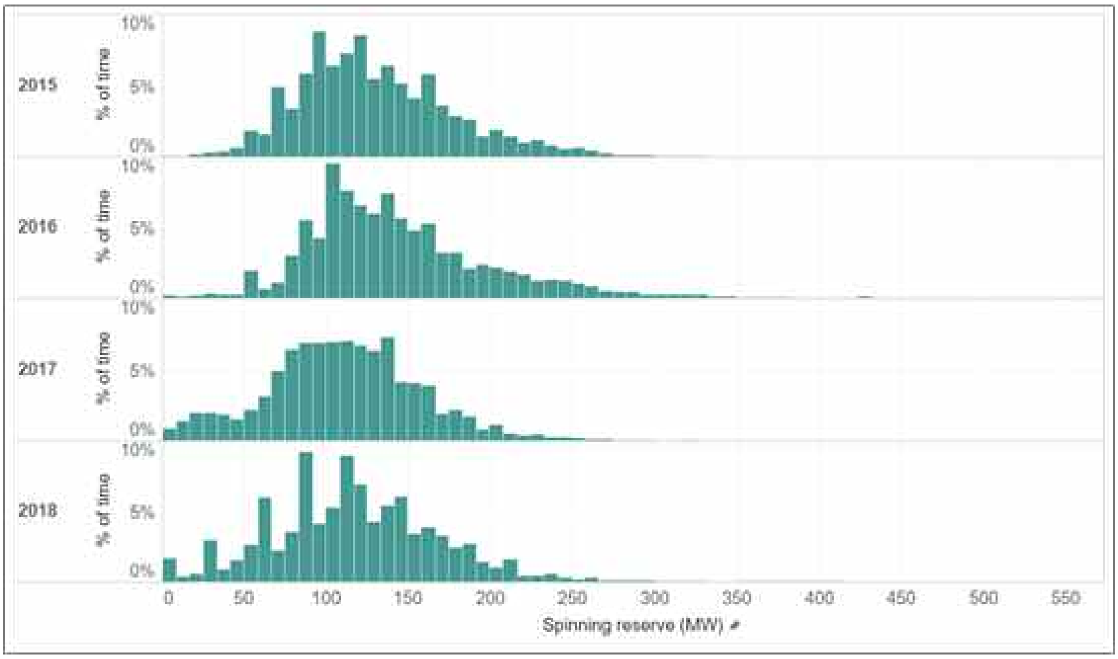
To consider the effect of this assumption, we have repeated our analysis of available ramping in South Australia, but have used spinning reserve rather than considering all generation that is bid as available – see Figure B.20. There are clearly substantial differences between the amount of spinning reserve and the amount of available ramping, as calculated earlier. In 2017 and 2018, there have been a higher number of instances where spinning reserves are very low (i.e., less than 50 MW) than in 2015 and 2016.

The Commission considers that there is a benefit in distinguishing between:

- ramping capability, which can refer to the ability to ramp over a range of time-scales, and
- spinning reserve, which is effectively the ability to ramp over a very short period of time, say five minutes.

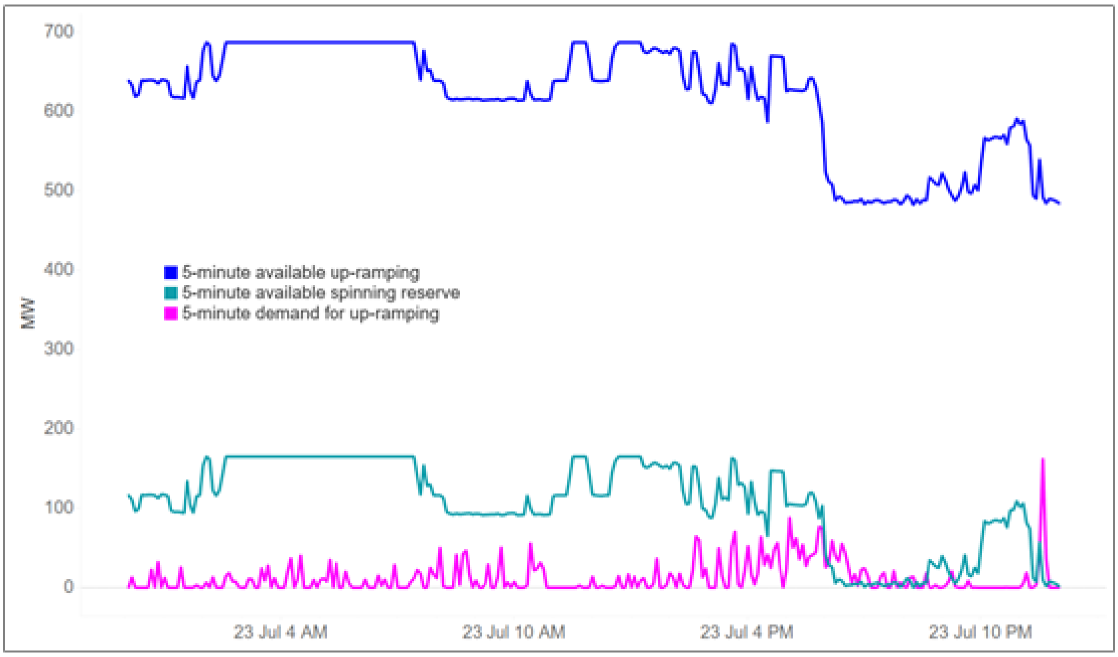
The distinction is important – in South Australia, there appears to be ample ramping capability available that can be brought online over a period of between 10 and 30 minutes. But in contrast, the rise in penetration of intermittent generation may be causing shortages of spinning reserve. The difference is borne out by considering the example of 23 July 2017 – Figure B.21. We can see that although there was plenty of available ramping (i.e., including fast-start units that can be brought online) levels of spinning reserve were very low over this period.

Figure B.20: Distribution of spinning reserve, 5-minute interval basis, January 2015 to June 2018, South Australia



Source: AEMC analysis of MMS data.

Figure B.21: 5-minute demand for ramping-up versus 5-minute available spinning reserves versus 5-minute available ramping-up, 23 July 2017



Source: AEMC analysis of MMS data.

In summary:

- In South Australia, there appears to be ample ramping capability available that can be brought online over a period of between 10 and 30 minutes. But in contrast, the rise in penetration of intermittent generation may be causing shortages of spinning reserve.
- Victoria has less ramping-up capacity available than in 2015, with the decline coinciding with the closure of Hazelwood. Ramping-up capability has reduced with other plant (e.g., Mortlake) operating at higher levels.

B.3.4 Relationship between ramping and price

The final part of the quantitative analysis is to examine the relationship between ramping and prices. In particular, we seek to identify whether there is any evidence that prices rise in response to a greater need for ramping. Put another way, is there a relationship between demand for scheduled generation and prices.

Relationship between ramping and price over a 3-hour time-scale

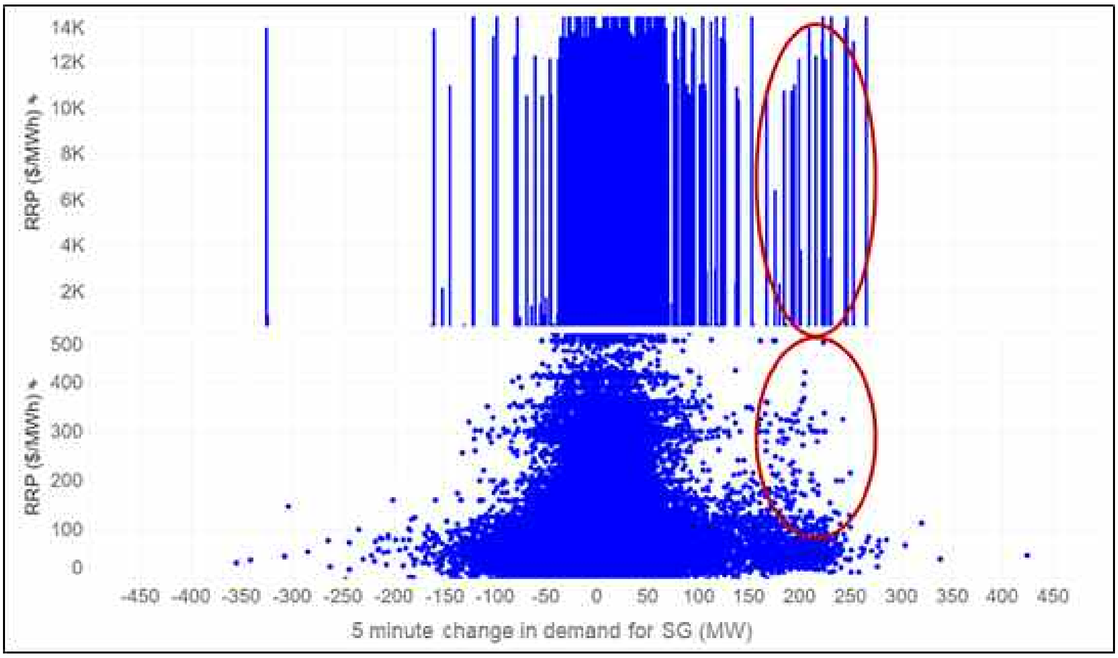
We have analysed the relationship between 3-hour ramping demand and price in South Australia, and have identified that there is no clear relationship between the two variables. This is unsurprising given that there is ample ramping-up capacity over three hours – ramping is not associated with high prices over this time scale.

Relationship between ramping and price over a 5-minute time-scale

Figure B.22 shows the relationship between the 5-minute change in demand for scheduled generation versus the 5-minute price. By way of explanation, the horizontal axis shows the change in demand – i.e., the demand for ramping – versus the 5-minute price (vertical axis). The bottom panel shows prices between $0 and $500 per MWh; the top panel shows prices above $500 per MWh, on a different scale.

There appear to be times when higher demand for ramping is associated with higher prices, as indicated by the red circles.

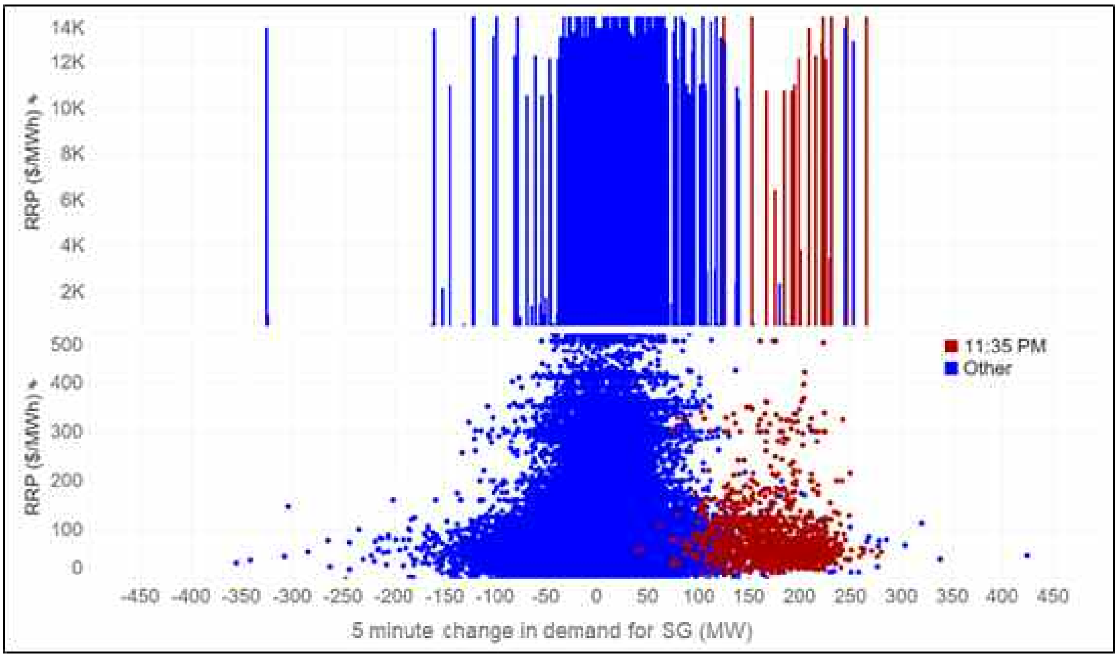
Figure B.22: 5-minute change in demand for SG versus 5-minute price, South Australia



Source: AEMC analysis of MMS data.

We investigated why these high ramping, high price periods are occurring. Figure B.20 shows the same plot as Figure B.23, but highlighting those observations that occurred in the dispatch interval ending 11:35 pm.

Figure B.23: 5-minute change in demand for SG versus 5-minute price, South Australia



Source: AEMC analysis of MMS data.

The vast majority of the high ramping, high price periods occur at 11:35 pm at night and are associated with the South Australia off-peak hot water load.

This phenomenon is unrelated to the rising penetration of renewables – the spike in demand caused by off-peak hot water load has been around for the last decade. The market has managed these spikes in demand effectively for a long time. The price outcomes show that the market provides price signals to generators that make themselves available during these periods.

In summary:

- Analysis shows that high demand for ramping (on a 5-minute basis) in South Australia is associated with high prices.
- These outcomes are primarily driven by the off-peak hot water load that occurs late at night, and is a phenomenon that has been present in the market for a long time.
- It follows that that the market provides price signals for ramping, and that these price signals have supported the adequate supply of ramping for many years.

B.4 Ramping markets overseas

Markets overseas are grappling with similar issues as those being considered in this appendix, regarding dispatchability and flexibility in light of an increased penetration of variable renewable generation. A number of these markets have introduced products that explicitly reward ramping capability.

The discussions above in sections B.2 And B.3 have indicated that based on analysis to date there is likely to be adequate ramping availability in the NEM. However, it is informative to understand why overseas markets have introduced ramping products.

The Commission has examined ramping products of three overseas markets: California, the mid-west of the USA and Ireland. These are discussed below.

B.4.1 What are ramping products and markets?

There are no explicit ramping products or markets in the NEM.

From observing markets overseas and for the purpose of this report, the Commission defines a ramping product as an explicit product sold by a provider of ramping capability. The buyer of a ramping product is typically the system operator.

By "ramping capability", we mean the ability to quickly and controllably adjust generation or load up and/or down over a period of time equal to or greater than the dispatch interval (i.e., five minutes, in the NEM).[393]

A ramping market is the mechanism through which ramping products are procured and paid for.

B.4.2 California and the midcontinent electricity markets

The Californian energy market is operated by the California Independent System Operator (CAISO).

The Midcontinent Independent System Operator (MISO) is the system operator for the electricity market in the Midwest United States, parts of the southern United States, and Manitoba, Canada.

What problem are they trying to address?

Both of these Independent System Operators (ISOs) have recently introduced ramping products (MISO in April 2016[394] and CAISO in November 2016[395]) in order to address a problem that is broadly the same in both markets. For that reason this section discusses both products together.

Unlike the NEM, both ISOs employ a dispatch engine that seeks to minimise the aggregate cost of generation over two dispatch intervals.

This means that, where it is economic to do so, ramping required for the second dispatch interval can be procured from the first interval by constraining down non-marginal generators that would otherwise be dispatched at maximum output and constraining up the generator at the margin to make up the difference. This dispatch outcome provides "headroom" for the

393 The ability to adjust generation/load in a period of time less than 5 minutes is the domain of frequency control ancillary services

394 RTO Insider, *MISO seeks to Launch Ramp Product April*, https://www.rtoinsider.com/miso-ramp-product-april-1-21339/, 18 January 2016.

395 CAISO, *Flexible Ramping Product Uncertainty Calculation and Implementation Issues*, http://www.caiso.com/Documents/FlexibleRampingProductUncertaintyCalculationImplementationIssues.pdf, 18 April 2018.

non-marginal generators to ramp up in the subsequent interval to avoid the need to dispatch a higher cost generator.

However, constraining down those generators in merit order to boost ramping capability in the second interval reduces the revenues those generators would have otherwise earned in the first interval. This weakens the signal to invest in higher ramping capability.

As variable renewable generators become increasingly prominent in the generation mix, this problem is intensified because of the greater amount of ramping (and ramping contingency) that the ISO requires for upcoming dispatch intervals. The ISO will more frequently and materially constrain down in-merit-order generators, and hence more significantly weaken the incentives of generators to provide ramping capability.

This problem is illustrated in the example below.

Simplified example of the problem

Assume there are four generators with the following characteristics as shown in Table B.4.

Table B.4: Assumptions

GENERATOR	MAXIMUM CAPACITY (MW)	MAX RAMP RATE PER DISPATCH INTERVAL (MW/5 MINS)	OFFER ($/MWH) (ASSUMED EQUAL TO MARGINAL COST)
A	50	1	29
B	50	10	29
C	50	15	30
D	50	20	20

Each unit has the same maximum capacity but different ramp rates and offer prices. For the purpose of this example, the offer prices are assumed to equal the short run marginal cost of generation. As noted above in section B.2, in the NEM this is not the case; instead bids reflect a range of different factors.

The following loads are forecast by the ISO:

- The load for the upcoming 5 minutes (interval 1) is 130 MW.
- The best estimate of forecast load for the subsequent 5 minutes (interval 2) is 150 MW, requiring a ramping need of 20 MW per interval.
- We assume for the purpose of this example that the forecast load for interval 2 actually occurs. In practice the ISO may have some contingency ramping requirements. This will make the problem more material.

First, assume that the ISOs' dispatch engines do not seek to optimise dispatch over multiple dispatch intervals. Note this is not what MISO or CAISO do, and is discussed to illustrate the source of problem.

Dispatch for intervals 1 and 2 are as below.[396]

Table B.5: Interval 1, not multi-period dispatch

GENERATOR	DISPATCH (MW)	MARKET PRICE ($/MWH)	REVENUE ($)	COST ($)	PROFIT ($)
A	50	30	1500	1540	50
B	50	30	1500	1450	50
C	30	30	900	900	0
D	0	30	0	0	0
Total	130		3900	3800	100

Table B.6: Interval 2, not multi-period dispatch

GENERATOR	DISPATCH (MW)	MARKET PRICE ($/MWH)	REVENUE ($)	COST ($)	PROFIT ($)
A	50	200	10000	1450	8550
B	50	200	10000	1450	8550
C	45	200	9000	1350	7650
D	5	200	1000	1000	0
Total	150		30000	5250	24570

Note, in interval 2, generator D is dispatched because generators A and B are at maximum output so cannot ramp and generator C can only ramp at 15 MW per interval – less than the 20 MW required.

Now consider what the ISOs' dispatch engines actually do to seek to optimise over multiple periods (two periods, in the example). Noteworthy numbers are bolded.

Table B.7: Interval 1, with multi-period dispatch

GENERATOR	DISPATCH (MW)	MARKET PRICE ($/MWH)	REVENUE ($)	COST ($)	PROFIT ($)
A	**49**	30	1470	1421	49

396 Note that revenues costs and profits throughout this example should be divided by 12 (60mins/5mins) to account for the price being in MWh but the dispatch intervals being 5 minutes. For the purpose of making the arithmetic more simple this has not been done. It does not affect the conclusions.

GENERATOR	DISPATCH (MW)	MARKET PRICE ($/MWH)	REVENUE ($)	COST ($)	PROFIT ($)
B	**46**	30	1380	1334	46
C	**35**	30	1050	1050	0
D	0	30	0	0	0
Total	130		3900	3805	95

Table B.8: Interval 2, with multi-period dispatch

GENERATOR	DISPATCH (MW)	MARKET PRICE ($/MWH)	REVENUE ($)	COST ($)	PROFIT ($)
A	**50**	30	1500	1450	50
B	**50**	30	1500	1450	50
C	**50**	30	1500	1500	0
D	**0**	30	0	0	0
Total	150		4500	4400	100

In order to mimimise overall (two-interval) costs:

- Generators A and B are constrained down by 1 MW and 4 MW respectively in interval 1, to provide "room" to subsequently ramp up to meet expected demand in interval 2.
- Generator C is constrained up by 5 MW in interval 1, but remains marginal.
- Because of the headroom created by constraining down generators A and B, generator D is not dispatched in interval 2.

This process increases costs slightly in interval 1, but avoids having to incur higher costs in interval 2. This is shown in the table below.

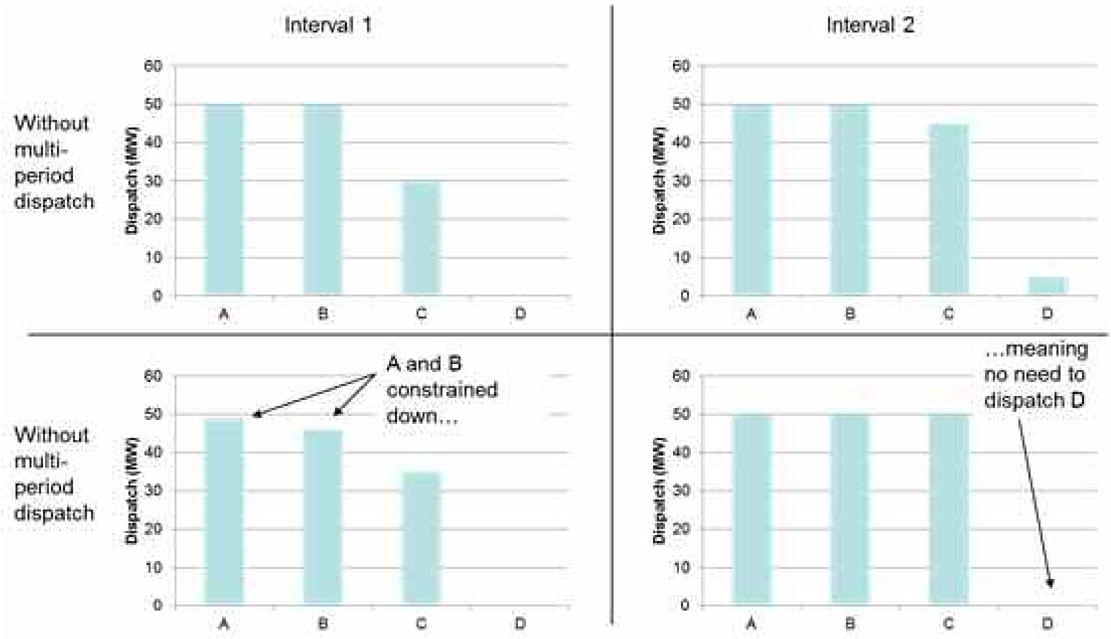
Table B.9: Cost of dispatch comparison

COST OF DISPATCH ($)	INTERVAL 1	INTERVAL 2	TOTAL
Single period dispatch (Tables B.5 and B.6)	3800	5250	9050
Two period dispatch (Tables B.7 and B.8)	3805	4400	8205

COST OF DISPATCH ($)	INTERVAL 1	INTERVAL 2	TOTAL
Difference	-5	+850	+845

These outcomes are represented diagrammatically below:

Figure B.24: Dispatch outcomes



As shown by the example, generator A is constrained down by less than generator B because it has a slower ramp rate. There is no value in constraining down generator A any further as it will be unable to ramp any faster than 1MW per interval.

However, a consequence of this is that generator A is more profitable than generator B, despite having poorer ramping capability. In turn, this provides disincentives to have ramping capability, impacting efficient operational and investment decisions. The ramping product was designed to fix this problem, enhancing reliability and market performance.[397]

What is the ramping product?

The ramping product compensates those generators that are constrained down to provide ramping capability for future intervals. The compensation is equal to the marginal opportunity cost for constraining down those generators. In our example, both generators incur the marginal opportunity cost of $1/MWh:

397 Ibid, p.3.

- generator A is constrained down by 1MWh and has an opportunity cost of $1 (the difference between the $50 it would have made had it not been constrained down and the $49 it actually made)
- generator B is constrained down by 4MWh and has an opportunity cost of $4

This restores the otherwise weakened incentive to provide ramping capability to the market.

The money for the ramping product is recovered through an uplift charge, and ultimately from consumers. The ramping product is not a "make-whole payment" (if make whole payments are defined as the difference between actual costs incurred and revenues recovered through the energy market). For example, make whole payments are used in markets with centralised unit commitment when generators are constrained on ahead of real time but ultimately not dispatched. Instead, we have a situation where generators are constrained down, creating opportunity costs (not explicit costs).

Insights for the NEM

The California and the mid-west ISOs identified the need to procure ramping products primarily because they procure ramping capability over two dispatch intervals and this sometimes means they have to pay generators to be constrained off in the first interval in anticipation of future ramping requirements.

The rationale for CAISO/MISO's ramping product therefore does not appear relevant in the current NEM design. Only substantial redesign (i.e., the NEMDE seeking to optimise dispatch over multiple periods) would provoke the possible need for ramping products of the type used in the Californian and the midcontinent markets.

We note that the example above is highly stylised (e.g. in the NEM generators do not bid at SRMC) and is constructed to demonstrate how ramping markets operate in MISO and CAISO. For the reasons discussed in Appendix B.2, it is not appropriate to conclude from the example that centralised unit-commitment results in more efficient dispatch outcomes than those of the NEM.

Members of the technical working group agreed with these findings when presented this case study on 4 June 2018.

B.4.3 Ireland

In 2013, Eirgrid[398] undertook an exercise to model the 2020 power system with specific focus on the likely system scarcities which would arise in the power system (reserve, inertia, reactive power, ramping) given forecasted revenue streams of generation based on the revenue streams available at the time (energy, capacity and ancillary services). The results of the analysis found that there was not sufficient revenue streams or market signals available to the overall generation portfolio to meet the system scarcities identified – of which ramping capability was one of these scarcities.[399]

On this basis, Eirgrid introduced three ramping products, as outlined in the table below.

398 Eirgrid is the transmission system operator for the Republic of Ireland.
399 Ibid.

Table B.10: Eirgrid's ramping products

PRODUCT	RAMP-UP REQUIREMENT	OUTPUT DURATION
Ramping margin 1	1 hour	2 hours
Ramping margin 2	3 hours	5 hours
Ramping margin 3	8 hours	8 hours

Ramping margin is defined by Eirgrid as the guaranteed margin that a unit provides to the system operator at a point in time for a specific horizon and duration. Ramp-up requirements refers to the time it takes for the ramping product to reach its required output; output duration refers to the length of time that the output must be maintained for.[400]

Eirgrid and SONI[401] procure these products. A regulated tariff is paid by them (and recovered from transmission use of system (TUoS) charges) to all technically eligible service providers for the quantity of the service required.

The theoretical analysis outlined in section B.2 and quantitative analysis outlined in section B.3 indicate that ramping does not appear to be an urgent issue in the NEM, and that there may be sufficient incentives in the wholesale market for market participants to deliver sufficient ramping capacity in the future without a specific ramping product to provide an additional revenue stream.

In drawing these conclusions, the Commission notes an important difference between the design of the island of Ireland's energy market in comparison to the NEM. The Irish market has a market price cap of €1,000/MWh (~$1,500/MWh), an order of magnitude less than in the NEM. This may mean that in Ireland, generators' weighted average expectations of future prices may be less than those required to provide sufficient ramping capability to the system in operational and investment timescales. As noted earlier, the conclusions drawn in that section are predicated on the market price cap being sufficient high.

400 See: http://www.eirgrid.ie/site-files/library/EirGrid/DS3-System-Services-Portfolio-Capability-Analysis.pdf

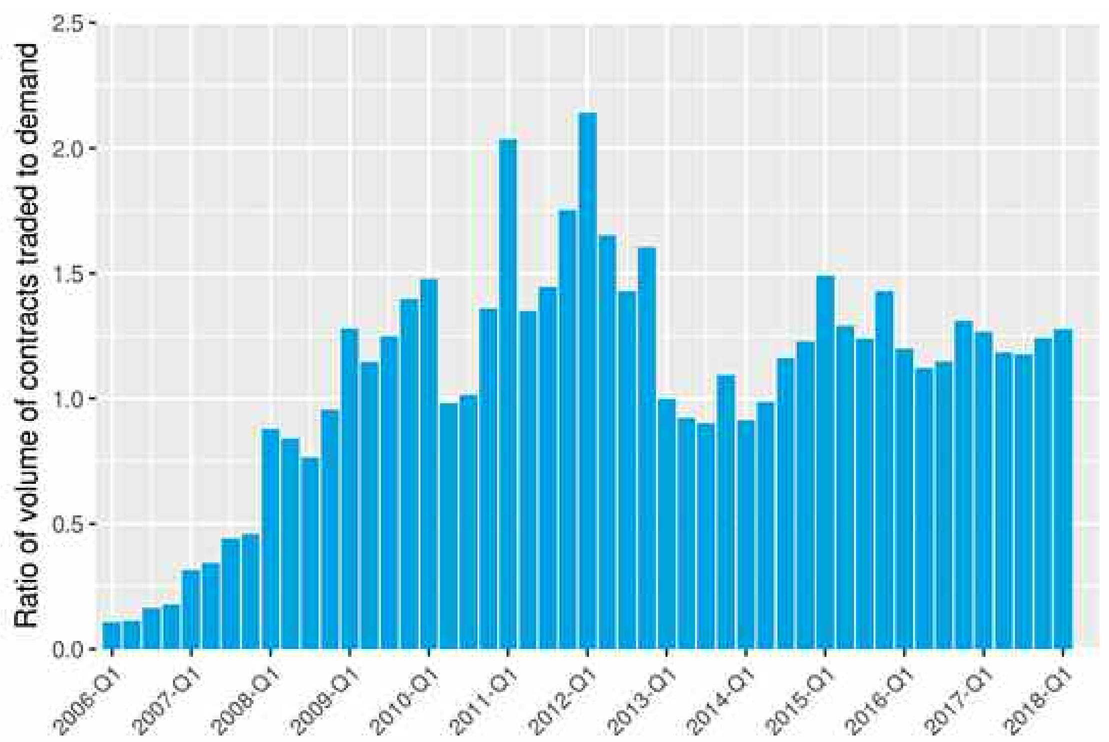
401 SONI is the transmission system operator for Northern Ireland

C UPDATED CONTRACT MARKET CHARTS

The figures below are updates of figures that appeared in the Interim report. They were produced to provide another view of contract trading data to try to emulate charts produced by stakeholders in response to questions about the health of the contracts market posed in the issues paper.

Figure C.1 updates figure 5.4 in the interim report, which was produced to see if trading of ASX quarterly base future contracts as a ratio of demand might be waning, as suggested by the Grattan Institute.[402] The two extra quarters added to the chart show a slight increase and confirm what we said in the interim report. That is, despite the decline since those highs in the first quarter of 2011 and 2012, recent levels of trading do not appear to be of significant concern, nor obviously trending downwards.

Figure C.1: ASX quarterly base futures – Volume traded as ratio of demand NEM-wide

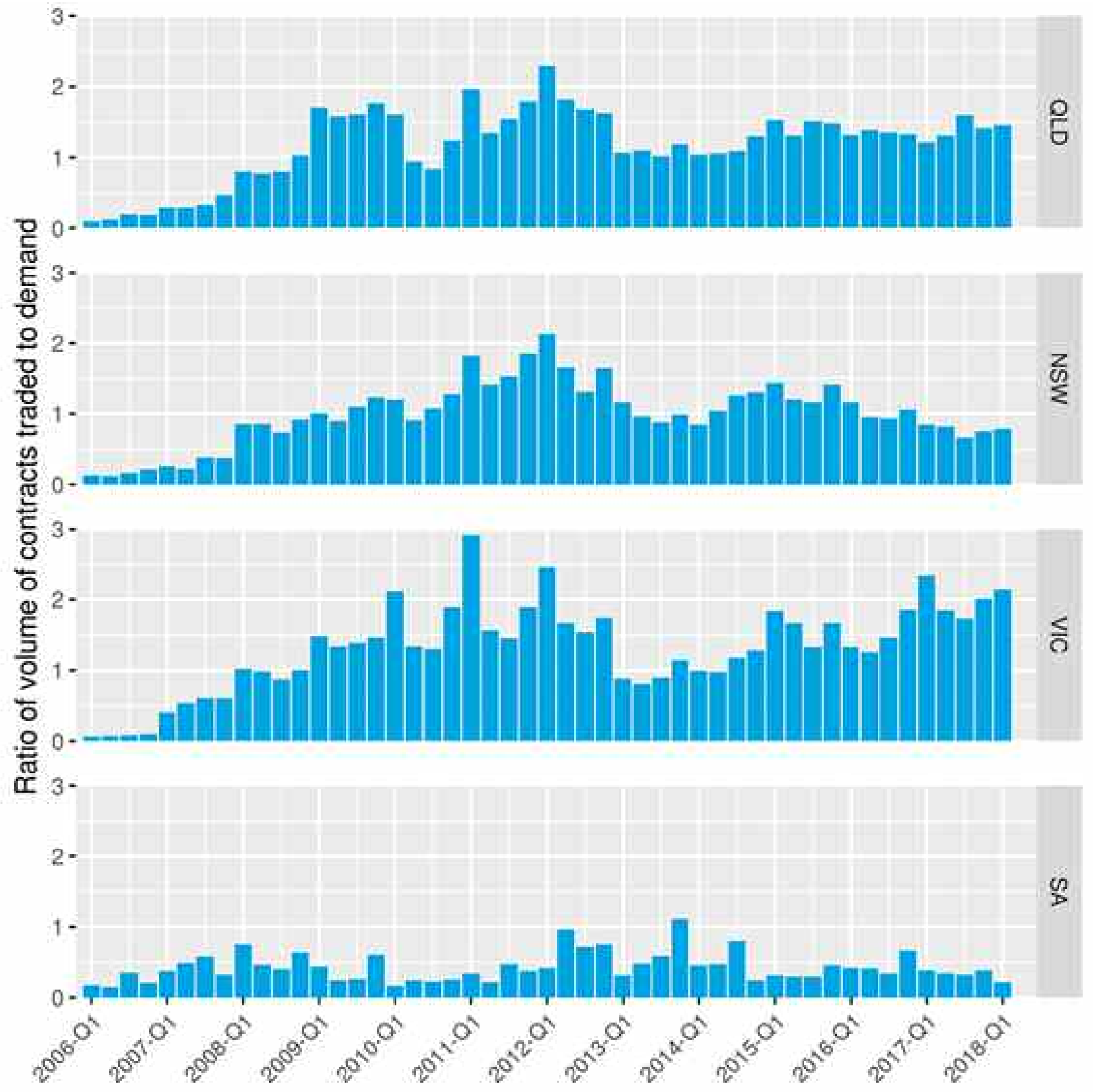


Source: AEMC from ASX data

Figure C.2 updates figure 5.5 in the interim report, which splits trading into four regions: South Australia, Victoria, NSW, and Queensland.

402 Grattan Institute, Next generation: the long-term future of the National Electricity Market, https://grattan.edu.au/report/next-generation-the-long-term-future-of-the-national-electricity-market/, September 2017, p. 20.

Figure C.2: ASX quarterly base futures – Volume traded as a ratio of demand by region



Source: AEMC from ASX data

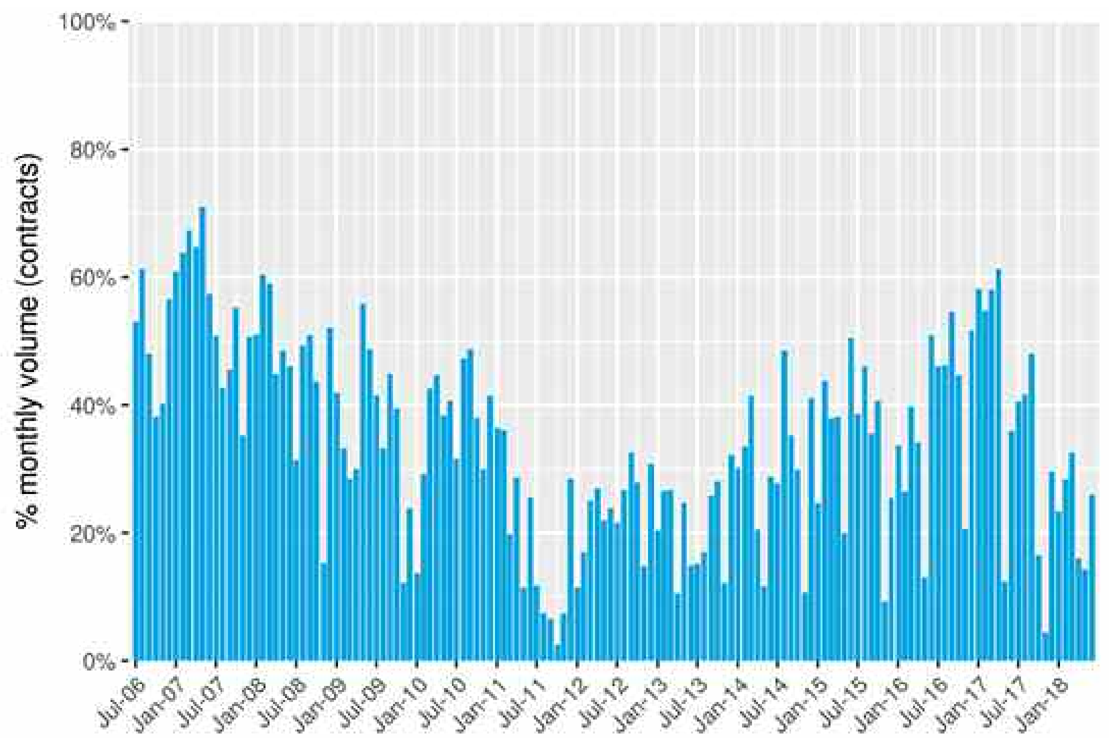
The two extra quarters added to the chart show slight increases in New South Wales and Victoria and decreases in Queensland and South Australia. Overall, base futures contracts:

- continue to be thinly traded in South Australia
- show signs of recovery after a period of decline in New South Wales
- are trading at relatively healthy levels in Queensland and especially in Victoria.

These results appear consistent with similar charts presented by the ACCC in the final report of its Retail Electricity Pricing Inquiry.[403] which plots total quarterly volume of traded flat swap product v/s total demand, by region, including both ASX and OTC trades in quarters 3 and 4 of 2017 and forecasts ASX and OTC trades for all four quarters of 2018. The ACCC's access to both OTC and ASX contract trading provided it with insights that lead it to recommend (recommendation 6) that the details of OTC trades be submitted by participants to a repository to improve the information the market bodies and market participants have on contract trading.

Figure C.3 updates Figure 5.6 in the Interim report, which was produced to see if most electricity is contracted for less than one year, as suggested by the Grattan Institute.[404] The updated chart shows the percentage of long traded contracts (over one year) has waned since the chart was last produced.

Figure C.3: ASX quarterly base futures – Percentage of long traded contracts (over 1 year)



Source: AEMC from ASX data

403 ACCC, *Restoring electricity affordability and Australia's competitive advantage*, Retail Electricity Pricing Inquiry—Final Report, June 2018, Figure 5.3, p. 143.

404 Ibid, p. 21.

D CONSIDERING THE SUITABILITY OF DAY-AHEAD MARKET IN THE NEM

BOX 11: KEY POINTS

- The Finkel Review recommended that the Commission and AEMO assess the suitability of a day-ahead market in the NEM.
- The Commission has considered the objectives that an ahead market could achieve and the potential design options that would need to be considered in order to achieve these objectives.
- The Commission does not consider that a US-style ahead market (that would move unit commitment decisions from market participants to the system operator) would be suitable in the NEM in order to manage reliability outcomes – it would not be in the long-term interests of consumers.
- However, although it appears that a move to centralised unit commitment is not justified for reliability reasons, it may require further consideration in terms of the potential security benefits that may accrue. While this review has not considered system security benefits in detail the Commission's conclusions note the potential for an ahead market to provide system security benefits and recommends further consideration of these potential benefits.
- These potential system security benefits from centralised unit commitment will likely only accrue after new markets or mechanisms have been introduced to value system security services such as system strength and inertia. The identification of system security issues and the subsequent creation of such markets should be prioritised over implementation of a centralised US-style ahead market. To this end, AEMO and the AEMC will continue to work together on identifying potential deficiencies with the current market arrangements.
- The Commission considers that there may be some benefits to the introduction of a voluntary, contract-based short-term forward market in the NEM. As discussed in appendix A, the Commission recommends that AEMO should undertake work on how a short-term forward market could be developed that would allow participant-to-participant trading of financial contracts closer to real time with the aim of providing the demand side with more opportunities to lock in price certainty.

D.1 Introduction

The Finkel Panel recommended that Commission and AEMO "consider the suitability of a day-ahead market to assist in maintaining system reliability".

The Commission has progressed this recommendation through the analysis conducted as part of this review.

A key finding of the Commission's analysis is that the NEM, despite not having a formalised day-ahead market, has many features which play a similar role to that of a day-ahead market. These features include information that is provided to AEMO as part of the pre-dispatch process, supported by a liquid financial derivatives market and the ability to rebid capacity up to five minutes before the dispatch interval. Rebidding provides participants with the flexibility to adjust their position in response changes in market conditions as well as responding to offers or bids of other participants.

This appendix outlines the Commission's analysis of ahead markets and the stakeholder feedback we have received in response to the directions paper. It also provides the Commission's conclusions and recommendations with respect to ahead markets.

D.2 The Commission's analysis of ahead markets in the interim report and directions paper

The interim report of this review discussed two widely-used ahead market designs: a European-style ahead market that facilitates participant-to-participant trades ahead of real-time; and a US-style ahead market that facilitates participant-to-system operator actions as a tool to schedule reliable operations. The Commission notes that there is an ahead market design in operation in Australia. The Wholesale Electricity Market (WEM) in Western Australia has both an ahead market and a balancing market. The Western Australian market is described in more detail in the Box 12.

BOX 12: THE WHOLESALE ELECTRICITY MARKET IN WESTERN AUSTRALIA

The Wholesale Electricity Market (WEM) in Western Australia has a different market design to the NEM. The main features of this market are:

- **Reserve capacity mechanism:** The primary role of the reserve capacity mechanism is to ensure that there is adequate generation and demand side management capacity available each year to meet peak system requirements including a reserve margin. Each market customer is required to contract for "capacity credits" to cover their share of capacity procured to cover the total system requirement. The market operator (AEMO) assigns capacity credits to suppliers of registered capacity. If there are insufficient capacity credits to meet requirements, AEMO will run an auction to procure more so as to cover the remaining requirements of market customers
- **Bilateral contracts:** Bilateral trades of energy and capacity occur between market participants and the AEMO has no interest in how these trades are formed. However, market participants are required to submit bilateral schedule data pertaining to bilateral energy transactions to AEMO each day so that the transactions can be scheduled.
- **Short-term energy market (STEM):** The STEM is a daily forward market for energy that allows market participants to trade around their bilateral energy position, producing a net contract position. A STEM auction is run for each trading interval of the next trading

day, determining a STEM clearing price and clearing quantities. The combined net bilateral position and STEM position of a market participant describes its net contract position.

- **Dispatch and balancing process:** The balancing process involves AEMO determining actual generation requirements and a balancing price for each trading interval. Generators receive (pay) the balancing price for any quantity above (below) their net contract position. Market customers pay (receive) the balancing price for any quantity above (below) their net contract position.

We note that there are a number of differences between this market design and the NEM. First the WEM includes a capacity mechanism. Generators receiving capacity credits in the capacity market must offer all of their available capacity into the STEM and balancing market, preventing the physical withholding of capacity.

Second, the WEM rules require suppliers to provide energy at their reasonable expectation of SRMC. This and the ex-post monitoring and investigation of bidding behaviour seek to mitigate the misuse of market power in the WEM. This is necessary because of the lack of effective competition in the wholesale energy market.

Given these differences between the Western Australian market and the NEM, we have not considered this market design further as part of this review.

The interim report found that a European-style ahead market is most similar to current market arrangements and there are a few barriers to the introduction of such a market in the NEM. The implementation costs of such a market would also be relatively low.

In contrast, the introduction of a US-style market was found to be more complex and would require significant consideration of the associated costs and benefits.

The directions paper focussed on US-style ahead markets only and identified three potential objectives this type of ahead market could be designed to achieve in order to assist with both reliability and security outcomes in the NEM. The objective of an ahead market is important as it will inform the design of such a market. The three objectives identified in the directions paper were:

1. To provide market participants (both supply and demand side) with more, or better quality, information so that they can incorporate this information into their unit commitment and demand response decisions and bids/offers and therefore increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.
2. To provide the system operator with more, or better quality, information so that the system operator can use the information to manage the system in relation to reliability and security outcomes.
3. To provide the system operator (rather than participants) with a schedule that centrally coordinates unit commitment decisions, the intent being to increase the efficiency of

outcomes in the NEM wholesale market, including in relation to reliability and security outcomes.

These three objectives exist on a spectrum, with the first objective being most closely aligned with the current NEM arrangements and the third objective being the biggest departure from the current NEM arrangements.

The directions paper also highlighted that, in this review to date, the Commission has sought stakeholder feedback on what existing ahead features of the NEM may require change. To date little feedback has been forthcoming and deficiencies in existing market design generally relate to information provision and / or security-related matters (e.g. not being sure whether there will be enough synchronous generators running in the system at a particular point in time), as distinct from reliability (having sufficient capacity or supply to meet demand).

Clearly identifying the deficiencies with the current market design is important. This is because clearly identifying what part of the existing market design may no longer be serving its purpose, and articulating the material causes of such an issue, is necessary in order to work out what the best solution is to address the deficiencies. Problem identification also helps to identify the causal link between reliability issues arising from the transformation of the sector and how these would be addressed through a formalised ahead market.

As discussed in chapter 5, AEMO is currently identifying the existing features of the NEM that happen ahead of real time that may require change and compiling the evidence of the deficiencies that it considers need to be addressed, either through targeted improvement to existing arrangements or, in the longer-term, through a centrally facilitated ahead market design.

D.3 Analysis from directions paper - Current NEM arrangements and potential changes

The directions paper used the three identified objectives outlined above as the basis for examining the current arrangements in the NEM and outlining areas that would require further consideration, should an ahead market be introduced in the NEM. This section summarises that work.

Objective 1 – providing better information to market participants:

The quality and credibility of the information available to market participants may be improved, relative to the current arrangements, through the introduction of an ahead market.

This is because market participants' intentions would become financially binding through their bids and offers in the ahead-market, which would be settled at the ahead price. This may result in better quality information being provided to the market as participants are incentivised to provide more accurate forecasts of their output and demand and therefore reveal their true intentions to the market at an earlier stage than is currently the case.[405]

405 Examples of how accuracy of forecasts is rewarded in an ahead market were provided in Box 4.3 of the day-ahead market chapter of the directions paper.

The ahead market may therefore provide participants with greater price certainty than the current market arrangements. Price certainty may be important to assist participants to manage price risk effectively and also may facilitate increased wholesale demand response in the NEM.

However, the current arrangements in the NEM provide market participants with large amounts of information from numerous sources. In addition, there are a number of more targeted changes that could be made to the current processes to provide the market with information. A number of recommendations to improve information provision in the NEM are discussed in chapter 3.

The Commission also notes that a short-term forward market, which is discussed in more detail in chapter 4 and appendix A, may be an alternative to a formalised ahead market that would also achieve the objective of providing the market with better information and price certainty.

Objective 2 – providing better information to the system operator:

The second objective discussed in the directions paper also related to information provision but this time it concerned the information that is provided to the system operator. This objective is framed around facilitating transparency of information to the system operator so that the system operator can better manage the system in respect of reliability and security.

As discussed above, the fact that market participants' intentions become financially binding through the ahead market may provide stronger incentives for market participants to provide the market, including the system operator, with credible information. The system operator could therefore make operational decisions informed by the outcome of the ahead market. Under the current market design the intentions of market participants revealed through pre-dispatch are not financially binding and so may be less reliable for the system operator. This is because currently in the NEM market participants have the ability to rebid capacity up until five minutes before each dispatch interval. Rebidding is discussed in more detail in the next section.

A benefit of an ahead market that we have heard from stakeholders is that it may reduce the number of out-of-market actions that the system operator undertakes relative to the status quo. In its submission to the directions paper AEMO noted that it has exercised its power of direction 20 times in South Australia since April 2017. AEMO considered that since it is increasingly relying on directions to manage the system in South Australia it is "in effect, running an ahead commitment process to make these services available but without the efficiency and price certainty of a market".

It should be noted that reliability directions are relatively rare and directions that AEMO are using in South Australia are for system security reasons, to make sure that there are enough services, other than energy and frequency control, available in the region. The objective being discussed in this section must therefore consider a wide range of potential benefits outside of potential reliability benefits. That is to say that it is unlikely that an ahead market would be appropriate purely on system reliability grounds but it may be justified if there are sufficient deficiencies with the current arrangements with respect to maintaining system security.

The extent to which an ahead market could reduce the number of out-of-market actions by the system operator is not clear at this stage. A number of potential deficiencies with the current market design would need to be identified to provide evidence to support this claim. These would include:

- The current pre-dispatch process does not provide credible information to the system operator.
- The system operator does not have sufficient information to operate the market without relying on out-of-market directions to an inefficient degree.
- The system operator has insufficient tools available to it in advance of dispatch to maintain reliability, but more likely security, to an acceptable level.

AEMO and the AEMC will continue to work together on identifying potential deficiencies with the current arrangements – particularly in relation to security issues.

Objective 3 - centralised unit commitment:

Chapter 5 and appendix B discusses the process currently used in the NEM, whereby each market participant makes their own unit commitment decisions. This section focuses on the third objective of an ahead market (as discussed in the directions paper) which was to move from decentralised to centralised unit commitment by the system operator.

An ahead market designed to achieve objective three would be the largest departure from the current NEM arrangements. A centralised commitment model, by definition, requires the system operator to take a view about the future and commit units on this basis. The risk of centralised unit commitment decisions taken by the system operator would likely be borne by all market participants (for example through "make whole" uplift payments for generators committed by the system operator but not required with the benefit of hindsight) and ultimately by customers.

In contrast, under the existing framework, individual market participants are responsible for gathering and evaluating information that they consider relevant in order to structure their bids and make unit-commitment decisions. Furthermore, both the unit-commitment decisions and the consequences of those decisions are borne by the individual market participants, who, providing the market is workably competitive, are unable to pass the costs associated with poor decisions through to consumers. In turn, this provides incentives for generators to gather and evaluate information to inform their commitment decisions in an efficient manner.

The current arrangements provide market participants with flexibility to respond to new information through the rebidding process.[406] Rebidding is explained in Box 13 below.

BOX 13: REBIDDING IN THE NEM

Rebidding provides participants with the flexibility to adjust their bidding position to respond to changes in market conditions, conditions relating to the generating unit or its fuel supply, network constraints as well as responding to offers or bids of other participants, as would be expected and necessary in a workably competitive market.

The practice of rebidding reflects the iterative process undertaken where generators reflect their intentions and physical condition of their plant through their bids.

Box 4.4 of the directions paper provided details of the incidence of rebidding in the NEM. It showed that while the trend in rebidding between 2007 and 2014 was downward, rebidding was still widely used and is an important mechanism for responding to changes in expectations and real-time events as they unfold. This allows for the most up-to-date information to be incorporated into dispatch outcomes.

The widespread use of rebidding also implies that market participants continually re-optimise their own portfolios in response to new information and reflect this through adjusting their bids.

The Commission understands that the decision to allocate to market participants both the decisions to commit units and the associated risks was a deliberate one when the NEM was established which is discussed in more detail in section 5.2 and chapter 2.

Of course, the market as a whole could be wrong in its view of the future, and reserves could be under-provided as a consequence of individual commitment decisions. Collectively and conceivably, insufficient generation may be available in any given dispatch interval. But, crucially, this is *unlikely* given the strong financial incentives placed on market participants through the spot and contract market. The historic low level of unserved energy in the NEM is evidence of this.[407] At its heart, the reliability framework seeks to balance the cost of lost load with the cost of investing and operating generation. The reliability standard and settings (including the market price cap) seek to balance this trade-off. In light of this trade-off the Reliability Panel has recently recommended that the reliability standard and settings for the

406 It is relevant to note that the AER recently released a report on the market outcomes in Victoria and South Australia since the closure of the Hazelwood power station. On 3 November 2016 the Treasurer and the Federal Minister for Environment and Energy requested that the AER monitor market developments in Victoria and South Australia in light of the potential for the closure of Hazelwood to enable anti-competitive behaviours among remaining generators. We were requested to provide advice to the Council of Australian Governments (COAG) Energy Council on any factors affecting the efficient functioning of the market within one year of the station's closure. The AER's key finding is that the exit of Hazelwood removed a significant low fuel cost generator, which was largely replaced by higher cost black coal and gas plant - at a time when the input costs of black coal and gas plant were increasing. These factors, in turn, drove significant increases in wholesale electricity prices. We found no evidence to suggest that prices were being driven by rebidding close to dispatch, or physical or economic withholding - behaviours more usually associated with the exercise of market power. See: https://www.aer.gov.au/wholesale-markets/market-performance/aer-electricity-wholesale-performance-monitoring-hazelwood-advice-march-2018

407 Over the past decade, unserved energy was only recorded in two years – once in 2008-09 when the reliability standard was not met and once in 2016-17, when it was well within the reliability standard. There was no unserved energy (i.e. reliability load shedding) observed in any other year over the last decade.

national electricity market (NEM) remain unchanged for the period from 1 July 2020 to 1 July 2024.[408]

As market conditions change, market participants' probability-weighted expectations of future spot prices change. For example, the high prevalence of variable renewable energy sources may serve to depress spot prices at certain times. But it will also increase the likelihood of very high spot prices: for example, when supply provided by variable, renewable energy resources unexpectedly and rapidly drops off. As through the process described in chapter 5 and appendix B, this should influence unit commitment decisions of other generators.

This discussion has focussed on operational decisions. However, similar arguments can be made with regard to investment decisions. The market provides incentives for investment in not only the correct quantity but also the appropriate type of generation capacity and potential demand response. As noted in chapter 5 and appendix B, commitment decisions can be influenced by the ability of plant to ramp quickly and the costs associated with committing and de-committing units. Those types of generators that are able to ramp quickly will incur fewer losses (or opportunity costs, depending on their contractual position) in the event that prices are high and they are not available, because they will be able to quickly commit. The time period over which they were unavailable is short. Similarly, those generators which are able to be committed at very low cost will be more profitable than those with higher commitment costs. This in turn improves the business case associated with investing in these types of generators, including through reducing the risk associated with entering into contracts for a large proportion of their capacity.

The introduction of five-minute settlement will further sharpen the incentives to make investment and operation decisions consistent with the needs of the system, while the proposed National Energy Guarantee should provide policy certainty regarding emissions reduction.

The directions paper notes that the introduction of centralised unit commitment and this form of ahead market would take time and significant costs to implement. It would therefore require careful consideration of the benefits that would accrue to the market to justify these costs. In the directions paper the Commission noted that in order for this type of day-ahead market to be implemented in the NEM the following questions would need further consideration:

- whether there are significant issues with the current process for market participants committing units for dispatch
- whether the centralised commitment model would result in a higher level of dispatch efficiency, and whether this would outweigh the costs of changing the market design
- whether there are system security issues that cannot be accommodated under the current market design (with appropriate changes) that an ahead market would address. The last point requires further consideration in the context of assessing the suitability of an ahead market in the NEM. It may be the case that new markets for system security services could be introduced under the current market design.

408 The market price cap and cumulative price threshold are adjusted annually in accordance with the formula in the NER.

D.4 Stakeholder views

There was much stakeholder comment on the subject of ahead markets in the submissions to the directions paper.

Generally, there was limited support for the introduction of an ahead market – regardless of whatever problem might be identified. Submissions from Major Energy Users, Flow Power, Infigen, Australian Energy Council (AEC), EPC Technologies, Australian Sugar Milling Council, ERM Power, Snowy Hydro and the Generator Group all indicated that they were not in favour of the introduction of an ahead market.

An independent consultant report submitted as part of the Generator Group submission stated that "[a] day-ahead market in the NEM seems to be a solution to a deficiency in the NEM that has not been clearly articulated." It concludes that a compulsory US-style ahead market is fundamentally incompatible with the NEM's design and philosophy of decentralised decision making. It further states that nearly all of the identified problems in the NEM can be addressed more effectively by means other than a compulsory ahead market.

AGL did not consider that the NEM needs dismantling and rebuilding and that the analysis presented by the Commission in the directions paper did not outline sufficient justification from any party for introducing an ahead market.

Some submissions indicated that they were supportive of an ahead market including those from S&C Electric, TransGrid, EUAA and BlueScope. However, both TransGrid and BlueScope were not in favour of an ahead market that would mean that unit commitment decisions were made by the market operator rather than by market participants, as discussed under the third objective in the directions paper. The submission from the Government of South Australia considered that an ahead market should be designed to provide market participants and the system operator with better information but that the current generator self-commitment arrangements should remain. The submission from BlueScope noted that demand-side bidding at the ahead stage may facilitate increased demand response. This is discussed in more detail in chapter 4.

S&C Electric Company indicated their support for an ahead market by stating that if the NEM already has an ad-hoc day-ahead process it should be properly formalised.

Several of the submissions discussed a short-term forward market, similar to a European-style ahead market, as an alternative to the introduction of a formalised, US-style ahead market. These are discussed in more detail in chapter 4. The main reasons to consider such a market were said to be the potential to provide market participants with greater price certainty and more options to manage price risk. This is considered to have a number of potential benefits, including facilitating more wholesale demand response.

<u>Problem identification:</u>

Submissions generally supported the Commission's analysis that the deficiencies with the current market arrangements that may be ameliorated by the introduction of an ahead market have not been sufficiently identified.

Some submissions stated that they could not comment on the need for an ahead market in the NEM until further work was done to identify the deficiencies with the current market arrangements.[409] Stakeholders were generally supportive of more work being conducted by the Commission and AEMO to identify the potential benefits of an ahead market in the NEM.[410] EnergyAustralia stated that they would be highly concerned if any recommendations were made in relation to the implementation of an ahead market prior to the release of analysis from AEMO.

The CEC added that should deficiencies with the current arrangements be identified to justify the introduction of an ahead market, a staged approach to implementation should be pursued. Snowy Hydro stated that an ahead market in the NEM appears to be a solution to a deficiency in the NEM that has not been clearly articulated.

Energy Networks Australia noted that it was important to establish a unanimous and well-understood objective for an ahead market was needed as this is fundamental to the design of such a market.

ERM Power noted that it is unclear how the introduction of an ahead market would improve on the NEM's current information obligations and the ability of participants to freely engage in hedge contracts or in what way it would provide further incentives to promote power system reliability. Snowy Hydro considered that the benefits of an ahead market are already addressed by the forward contract market that supports the NEM's real-time market. Given that market participants can already hedge price risk using financial derivatives under the current frameworks, ERM Power considered that any scheduling improvements from an ahead market are, likely to be limited.

The AEC agreed with the Commission's characterisation of the continuous iterative process of forecasting, adjustment and re-forecasting that currently occurs every day in the NEM. This process results in efficient and highly reliable scheduling outcomes that, according to the AEC, compare favourably to market designs that incorporate more centralised decisions. Therefore the AEC considered that the exact problem to be addressed and the ability of the current arrangements to address them remain nebulous.

The South Australian government noted that when AEMO provides additional work on the deficiencies with the current market arrangements, it expects that the Commission will prepare a more detailed assessment of an ahead market's ability to address these deficiencies.

<u>Comments on centralised unit commitment:</u>

The independent consultant report that accompanied the Generator Group submission discussed the issue of changing the market design from decentralised unit commitment decisions made by market participants to centralised unit commitment by the system operator in detail. The analysis concluded that there may be significant adverse impacts associated with centralised unit commitment, including:

409 ENA, CEC, Energy Efficiency Council and EnergyAustralia.

410 ENA, CEC, TransGrid, Aurora Energy, Major Energy Users, Hydro Tasmania.

- A globally less efficient unit commitment optimisation because participants' private information and opportunity costs cannot optimally be taken into account.
- Complications with settlement if there is a five minute dispatch interval settlement for real-time dispatch and a 30 minute dispatch interval for the ahead market.
- Inefficiencies in the spot market associated with a reduction in flexibility through restrictions on rebidding.
- Complications with offer structures and cost-recovery mechanisms that pervert the NEMS price signals. This includes issues around the recovery of start-up costs and the facts that uplift cost recovery mechanisms may not allow market participants to manage their exposures.
- The likelihood that incentives to invest in flexible generation and loads would be reduced.
- A compulsory two-settlement system would interfere with the contracting arrangements in the NEM.

ERM Power's submission was also not in favour of a move to centralised unit commitment. The submission noted that as an energy-only gross pool with a high market price cap, the NEM is designed to incentivise peaking plant to remain available even though it may only be used for several hours a year. The submission noted that the introduction of an ahead market in the NEM may dampen the current price signals that exist to bring about investment in flexible peaking plant. ERM considered that this may ultimately lead to higher costs for consumers, increased risks to reliability and an increase in the level of costly market interventions.

BlueScope's submission was also not in favour of centralised unit commitment as it considered that it is not in the best interests of the market. The submission noted that system operator will not be able to receive adequate information needed to make accurate decisions. The submission raised concerns that the costs of such a fundamental change to the competitive underpinnings of the market would not outweigh the associated implementation costs.

The submission from the South Australian government was not in favour of a move to centralised unit commitment. However the submission noted that a multi-settlement system may reduce the number of reliability and security out-of-market interventions by AEMO as it would have better quality information to rely on before dispatch.

AGL's submission did not support a move away from the flexibility currently afforded to participants in the NEM and considers that the rebidding rules and potential penalties for breach are a sufficient check on participant behaviour when it comes to signalling intentions. A move to centralised unit commitment is not supported for several reasons.

First, AGL considered that market participants are best placed to make unit commitment decisions as they hold all the relevant information underlying these decisions. Second, centralised unit commitment removes market participants financial incentives to bid their generation efficiently. Finally, such a market design is incompatible with the current market design principles in Clause 3.1.4 of the NER which provides for the minimisation of AEMO decision-making to allow market participants the greatest amount of commercial freedom to decide how they will operate in the market.

CS Energy considered that the best way to ensure reliability and security is to allow participants to respond to price signals. The submission considered that AEMO should not take the job of scheduling and dispatching plant out of the hands of participants, because participants have a profit motive and AEMO does not.

<u>Implementation costs versus benefits:</u>

Major Energy Users noted that any requirement for end users to provide ahead forecasts, with some penalty for poor forecasting, would impose considerable costs to end users and provide little benefit to the market.

ERM Power noted the scale of change required to implement an ahead market. It was also noted that a vast number of complementary changes, including in the financial contracts markets, to ensure that participants have the same incentives to be available and facilitate trading of hedge contracts to the same quantity levels as they do now. The submission also stated that it would be prudent to await the implementation of the National Energy Guarantee before deciding on major changes to market design arrangements.

TransGrid is supportive of the introduction of an ahead market as the long-term benefits of such a model include the increased ability for generators to understand and manage congestion risk. These potential benefits are desirable as the network evolves to incorporate a greater number and diversity of generators. However, TransGrid considered that it is important that the benefits to consumers are clearly demonstrated before implementing an ahead market. The submission recommended that the Commission explore the potential of an ahead market and other reforms to support the evolution of the NEM.

Meridian highlighted that caution should be exercised when considering radical departures from the current NEM design. Instead, the submission was supportive of continuing to consider the potential benefits associated with targeted development of the existing market rather than making wholesale changes.

EPC Technologies' submission stated that there were no material benefits in adding an ahead market and outlined the risks associated with such a market, including the risks to the efficiency of dispatch and risks of additional administrative burden on both the market and participants.

EnergyQueensland considered that the potential establishment of an ahead market could provide a range of benefits in improving forecasting and visibility of the operation of a range of intermittent and distributed energy resources at a network level. However, any disruption to current market arrangements would need careful and detailed consideration.

Aurora Energy was of the view that the costs of incorporating either a European- or US-style ahead market would outweigh any benefits given that a clear problem has not been identified at this time.

D.5 Commission's findings

This section summarises the Commission's conclusions with respect of the day-ahead market workstream.

It should be noted that although the primary focus of this review is reliability, consideration of a fundamental change to market design, such as the introduction of an ahead market, requires broad consideration of costs and benefits. For example, this review has not considered system security benefits in detail.

<u>Objective 1 – providing better information to market participants:</u>

The Commission does not consider that an ahead market with the objective of providing market participants with greater information is required to improve reliability outcomes in the NEM at this time. However, there may be some benefit associated with the introduction of a voluntary, contract-based short-term forward market in the NEM. The case for a short term forward market is discussed in more detail in chapter 4.

Consideration of a short-term forward market should be prioritised over an ahead market designed to achieve the first objective. To progress this idea, AEMC and AEMO will work together to assess the benefits of the introduction of a short-term forward market in the NEM.

In addition to a voluntary, contracts-based short-term forward market there may be other changes to the current arrangements, particularly with respect to information provision and forecasting that could achieve the same objective as an ahead market that is designed to achieve objective one. These are discussed in more detail in chapter 4. Again, the Commission considers that these more targeted changes to the current arrangements should be pursued instead of an ahead market.

<u>Objective 2 – providing better information to the system operator:</u>

It does not appear appropriate that an ahead market that is designed to provide better information to the system operator is required for reliability reasons. However, it may be the case that such an ahead market may provide some system security benefits. The Commission acknowledges that work is currently underway by AEMO and the AEMC to identify deficiencies with the current NEM arrangements, in relation to both system security and reliability.

In addition, chapter 3 recommends a number of changes to the current arrangements for information provision in the NEM. There are also a number of number of rule changes that the Commission is currently considering, or is likely to receive in the future, that relate to the information available to the system operator in advance of dispatch, for example related to pre-dispatch or MT-PASA. These rule changes may address any identified issues with respect to the information provided to the system operator.

<u>Objective 3 – centralised unit commitment:</u>

The Commission agrees with stakeholder comments that moving responsibility for unit commitment decisions from market participants to the system operator is not appropriate in the NEM to assist with reliability, consistent with the Finkel Panel recommendation on this. There are a number of reasons for this.

The first reason relates to the information available to different parties in advance of dispatch. Although the system operator has a whole-of-system view, it does not have sufficiently up-to-date or granular information on conditions at the individual plant level. It would be very difficult and costly for market participants to provide this information to the system operator in real time. Submissions from stakeholders did not identify any fundamental problems with information provision or the iterative process for making unit commitment decisions that currently exists in the NEM.

Second, as explained in chapter 2 the Commission has a preference for market-based, decentralised decision making over centrally-planned outcomes , consistent with the design and architecture of the NEM. The risks and costs associated with unit commitment decisions are most appropriately placed on market participants. This is because market participants have strong incentives to maximise their individual profits and therefore efficiently manage these costs and risks. The Commission considers that financial incentives are likely to provide the most robust and transparent driver for efficient decision making. Efficient outcomes can best be promoted by aligning the commercial incentives on businesses with the interests of consumers.

A central body, such as the system operator, does not have the same incentives and therefore outcomes may be less efficient under centralised unit commitment. This is because the primary role of the system operator is to manage the power system. In particular, in the NEM, the system operator is required to maintain power system security and manage the system to a reliable operating state (i.e. avoid involuntary load shedding) in an operational timeframe. It is not surprising, therefore, that the incentives on the system operator are to be on the conservative side, as expected by its role, rather than having the profit motive as an incentive. In turn, the cost of this conservatism is borne by consumers.

Third, the introduction of centralised unit commitment would be a significant departure from the current market design. The process of decentralised unit commitment is discussed in more detail in chapter 5 and the centralised commitment is discussed in more detail above. It is clear from these discussions that there is a large difference, both practically and philosophically, between decentralised unit commitment by market participants and centralised unit commitment by the system operator.

Moving from one type of unit commitment structure to another is therefore likely to impose significant costs and also consideration of potential complementary reforms to accompany this change, for example firm transmissions rights.[411] The costs of such a change to the current arrangements would need to be carefully weighed against the potential benefits. At this stage, the Commission does not consider that sufficient deficiencies with the current arrangements have been demonstrated to motivate a move to centralised unit commitment on reliability grounds. This is consistent with the feedback received from stakeholders in submissions.

411 The link between transmission rights and ahead markets is discussed in more detail in Appendix C of the directions paper.

Given the current level of policy uncertainty and significant changes currently occurring in the energy markets, the Commission considers it is important to be prepared for the future, and introduce significant changes when they are needed and can be most effective. Investments in technologies to maintain a reliable and secure system are crucial, and regulatory frameworks should set the pre-conditions, but not target specific technologies, so the market can coordinate and deliver outcomes in the most efficient way possible. Market and technological risks should be allocated to the parties with the strongest incentives and abilities to manage or mitigate those risks. This protects consumers from bearing the costs of mistakes.

Given these reasons, the Commission considers that a move to an ahead market with centralised unit commitment is not suitable for the NEM at this time to assist with reliability outcomes. Such a change is unlikely to be in the long-term interests of consumers and therefore does not meet the NEO.

However, the Commission acknowledges that work is currently underway to identify deficiencies with the current NEM arrangements, in relation to both system security and reliability. While it is not clear that an ahead market with centralised unit commitment would be beneficial from a reliability perspective it could - at some point in the future - provide some system security benefits.

It is the Commission's view that there is not a demonstrated problem with the current model for unit commitment in the NEM. Rather, there are insufficient market signals available to generators to provide system security services such as system strength and inertia. These issues are currently being demonstrated in South Australia through the sustained and persistent use of directions to maintain the system in a secure state. We note that the process for identifying the problems is ongoing and hence it is too early to design optimal solutions.

Until such time as system security services are valued, the Commission considers that a move to centralised unit commitment is unlikely to improve system security outcomes, or reduce the costs of interventions needed to maintain system security. This is because, no matter what market design is in place, it is not possible to maximise the efficiency of dispatch without placing an explicit value on the required system security services. In other words the value of these services must be explicitly included in the optimisation function in order for an efficiency maximising outcome to be found.

Given the number of changes that would be required in advance of an ahead market with centralised unit commitment providing any demonstrable system security benefits, the introduction of an ahead market of this kind is unlikely to meet the NEO for many years. Further, as noted above, any potential system security benefits associated with the introduction of an ahead market would need to be carefully assessed against the associated costs, which are likely to be substantial.

D.6 Conclusions

The Commission does not consider that a US style ahead market (that would change unit commitment decisions from market participants to the system operator) would be suitable in the NEM in order to manage reliability outcomes – it would not be in the long-term interests of consumers. There may be some system security-related benefits associated with a move to centralised unit commitment. AEMO and the AEMC will continue to work together on identifying potential deficiencies with the current arrangements – particularly in relation to security issues. This process is likely to take time and so the Commission considers that an US-style ahead market is unlikely to provide sufficient benefits to the NEM in the short- or medium-term.

There may be benefits associated with facilitating shorter-term trading in the NEM. These benefits include providing market participants with more options to manage price risk and to provide more price certainty to market participants. A benefit of increased price certainty is that it may facilitate more demand response in the wholesale market. The Commission has recommended that AEMO undertakes work to submit a rule change request to the Commission on how a short-term forward market could be developed that would allow participant-to-participant trading of financial contracts closer to real time with the aim of providing the demand side with more opportunities to lock in price certainty.

E UNSERVED ENERGY IN THE NEM

E.1 What is unserved energy?

As discussed in chapter 2, there are a number of causes of supply interruptions to customers: reliability (e.g. having insufficient generation, or interconnector capacity to meet demand); security (e.g. load being shed to manage frequency across the system); or network (e.g. a particular distribution line being out driving a network outage). This Review is concerned with reliability-related supply interruptions, as measured by the concept of "unserved energy".

In general terms, unserved energy means the amount of customer demand that cannot be supplied within a region of the NEM due to a shortage of generation, demand-side participation or interconnector capacity. Specifically, unserved energy is defined in Chapter 10 of the NER as:

"The amount of energy demanded, but not supplied, in a region determined in accordance with clause 3.9.3C(b), expressed as:

- GWh; or
- a percentage of the total energy demanded in that region over a specific period of time such as a financial year."

It is generally expressed as the latter of the two, i.e. as a percentage of total energy demanded in a region. The current reliability standard is a maximum expected unserved energy (USE) of 0.002 per cent of the total energy demanded in a region in a given year.[412] In simple terms, the reliability standard requires there be sufficient generation and transmission interconnection[413] in a region such that at least 99.998 per cent of forecast total energy demand in a financial year is expected to be supplied.

If the maximum expected unserved energy exceeds 0.002 per cent, then the reliability standard is not met. Any expected unserved energy below 0.002 per cent is considered to be within the reliability standard.

As a result, the concept of unserved energy underpins how we measure reliability in the NEM. AEMO and the Reliability Panel report on the percentage of unserved energy that has been historically observed annually.[414] AEMO also projects unserved energy through a range of processes (including the ESOO, medium-term PASA and short-term PASA), which all underpin the operationalisation of the reliability standard.

As discussed in chapter 6, if AEMO projects that unserved energy will exceed 0.002 per cent, it may take several actions, such as informing the market of the expected breach of the reliability standard or intervening in the market following a lack of market response to provide for the reliability standard to be met.

412 The Reliability Panel reviews the reliability standard every four years. The most recent review was completed in April 2018. It is available on www.aemc.gov.au under project reference REL0064.

413 Further detail on what constitutes generation and transmission interconnection for the purposes of unserved energy is set out in clause 3.9.3C(b), discussed further below.

414 See https://www.aemc.gov.au/markets-reviews-advice/annual-market-performance-review-2017

The appropriateness of the reliability standard and how it is operationalised is being considered by the Commission in the *Enhancement to the RERT* rule change request.[415] This analysis focusses on the definition of unserved energy in the NER instead.

E.2 What is included in the definition of unserved energy?

Clause 3.9.3C of the NER defines the 'reliability standard' and provides a link between the reliability standard and 'unserved energy'. Specifically, clauses 3.9.3C(b)(1) and (2) of the NER state what is included and excluded from unserved energy for the *purposes of the reliability standard*.

The NER state that unserved energy, for the purposes of the reliability standard, is to *include* unserved energy associated with *power system reliability* incidents that result from:[416]

- a single credible contingency event[417] on a generating unit or an inter-regional transmission element, that may occur concurrently with generating unit or inter-regional transmission element outages; or
- delays to the construction or commissioning of new generating units or inter-regional transmission elements, including delays due to industrial action or acts of God.

The NER also state that unserved energy is to *exclude* unserved energy associated with *power system security incidents*[418] that result from:[419]

- multiple contingency events, protected events or non-credible contingency events on a generating unit or an inter-regional transmission element,[420] that may occur concurrently with generating unit or inter-regional transmission element outages;
- outages of transmission network or distribution network elements that do not significantly impact the ability to transfer power into the region where the unserved energy occurred; or
- industrial action or acts of God at existing generating facilities or inter-regional transmission facilities.

In simple terms, the power system security events described above are excluded from unserved energy for the purpose of the reliability standard. For example, the 28 September 2016 black system event that occurred in South Australia was a power system security event and therefore supply interruptions from that event is not unserved energy for the purposes of the reliability standard – that is, this unmet demand is not considered when determining whether the reliability standard has been met.[421]

415 See https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

416 Clause 3.9.3C(b)(1) of the NER.

417 For example, this would be a sudden outage of a unit. Specifically, it is an event described in Clause 4.2.3(b) of the NER.

418 *The safe scheduling, operation and control of the power system on a continuous basis in accordance with the principles set out in Clause 4.2.6 of the NER.*

419 Clause 3.9.3C(b)(2) of the NER.

420 For example, an interconnector.

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

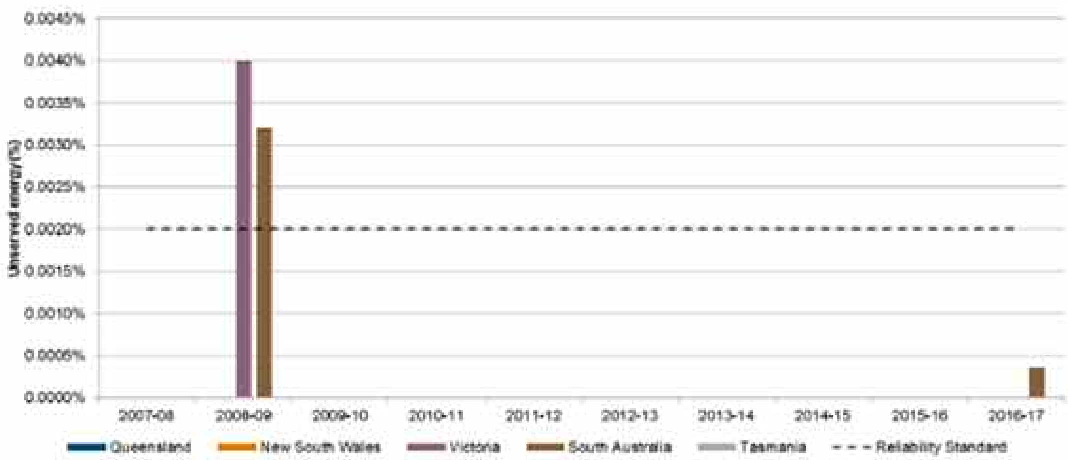
Similarly, on 1 December 2016, a fault on the Moorabool to Tarrone 500 kV transmission line in Victoria resulted in the loss of the Heywood interconnector between South Australia and Victoria and led to the disconnection of load.[422] The power system was not in a secure operating state after this incident. This was classified as a power system security event and so excluded from the calculation of unserved energy.

Importantly, the NER do not exclude all power system security events. While generally speaking, power system security events would be excluded, there could be instances where an event, not captured in the specific exclusions for the calculation of unserved energy set out in the NER, could be captured in the definition and calculation of unserved energy.

During some complex events, there may be both a power system security and power system reliability event occurring in parallel. For example, on 10 February 2017 in New South Wales, the supply-demand balance was tight and AEMO had issued a number of lack of reserve (LOR) notices to signal low reserve conditions. Typically, this would suggest a potential reliability event given that it relates to supply adequacy. However, a multiple contingency event occurred with all four Colongra units (667MW in total) failing to start when required[423] – this was the root cause of the unserved energy on the day. As per the definition of unserved energy, multiple contingencies are excluded.[424] This was therefore classified as a power system security event and excluded from the calculation of unserved energy.

As shown in Figure 2.1 in chapter 2, most supply interruptions are the result of distribution outages. Unserved energy for the purpose of the reliability standard is relatively rare in the NEM, as shown in the figure below.

Figure E.1: Unserved energy in the NEM



Source: AEMO

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

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

424 Clause 3.9.3C(b)(2)(i) of the NER.

There was only one such event in 2016/17, on 8 February 2017 in South Australia.[425]

High temperatures contributed to high demand on that day. At approximately six o'clock in the evening demand was higher than forecast, wind generation was lower than forecast, and thermal generation capacity was reduced due to forced outages. At this time, Engie, the operator of Pelican Point Power Station, notified AEMO that 165MW of capacity was unavailable. Engie advised AEMO of a start-up time for Pelican Point which would not have enabled AEMO to meet the system security requirements under the NER. Load shedding (100MW for 27 minutes) was then implemented by AEMO to restore system security.

E.3 Stakeholders' views

A number of stakeholders have commented on the definition of unserved energy throughout this Review :

- TransGrid stated that there should be a rethink of the unserved energy definition to include voluntary curtailment or curtailment of large loads.[426]
- Energy Networks Australia noted that there is consumer dissatisfaction with the amount of unserved energy reported vis-à-vis the amount of load shedding in NSW and that consumer expectations should be regarded as an important consideration in defining, and attaining a more holistic understanding of, unserved energy.[427]

TransGrid expanded on its comments in its submission to the directions paper. It stated that the current definition of unserved energy excludes occurrences from multiple contingency events, protected events and non-credible contingency events. It noted that occurrences similar to load shedding such as voluntary curtailment, mandatory restrictions and large market responses are also not included in the definition, even when the effect on consumers is similar to unserved energy. It therefore suggested a broadening of the definition would also better align it with the level of reliability experienced by consumers.[428]

E.4 Preliminary views

Unserved energy, as defined in the NER, prescribes which power system events should count towards a breach the reliability standard and which ones should not – by definition, it excludes events that are not related to supply inadequacy such as some power system security events or local distribution events.

In order to align the definition of unserved energy more closely with consumer experiences of supply interruptions as suggested by some stakeholders, supply interruptions from all sources, and in particular, supply interruptions from distribution networks as they make up the bulk of consumers' experiences of outages, would likely need to be included.

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

426 TransGrid, submission to interim report, pp. 2-3.

427 Energy Networks Australia, submission to interim report, pp. 4-5.

428 TransGrid, submission to directions paper, p. 5.

Furthermore, broadening the definition of unserved energy to reflect actual consumer experience of supply interruptions may have significant implications for investment – the reliability standard provides a signal to market participants as to how much reliability is expected of them, at a wholesale level. Including every single supply interruption event, as an example, would substantially inflate the amount of unserved energy and lead to over-investment in capacity (i.e. generation supply or demand response) at the wholesale level, with costs ultimately paid by consumers.

As a result, unserved energy for the purpose of the reliability standard is focussed on wholesale level reliability, or supply adequacy, and also accommodates in-market demand response.[429]

In response to these stakeholder comments, the Commission has considered the implications of broadening the definition to include the following events or types of supply interruptions.

Power system security including non-credible contingency events

Supply interruptions resulting from power system security events are typically addressed through the frequency control ancillary services (FCAS) markets. The Commission has an extensive work program examining power system security issues, including the *Frequency Control Frameworks Review*.[430] Simply having more generation or demand response capacity may not necessarily alleviate a power system security issue – for example, they may not necessarily participate in FCAS markets for provide the specific system security service that is required, for example system strength or inertia.

Network reliability

Network reliability is met through jurisdictionally-based frameworks.

There are existing state-based reliability standards which send a signal as to the level of reliability expected of network assets. Supply interruptions as a result of a network outage therefore count towards a breach of jurisdictional network reliability requirements (typically imposed through licence conditions), rather than a breach of the reliability standard.

Furthermore, simply having more generation capacity may not improve network reliability.[431] In fact, if not coordinated adequately, additional supply may put pressure on existing network assets.

Voluntary demand response including wholesale demand response

Voluntary curtailment in response to high prices (if spot-exposed), incentives from retailers or third-party aggregators or in response to jurisdictions' calls to reduce consumption are forms of wholesale or in-market demand response, i.e. consumers reduce demand in response to a signal, be it a price signal or otherwise.[432]

429 As demand response reduces total energy demanded.

430 See https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

431 However, more demand response could help with network reliability.

432 See chapter 4 for more details on the Commission's recommendations with respect to demand response.

The Commission sees voluntary demand response as being similar to additional generation, i.e. it is capacity at the wholesale level rather than avoided load shedding. Demand is this instance is not unmet – it is a voluntary action taken by the consumer to curtail consumption. In fact, it is currently treated as such in the unserved energy calculation since any wholesale demand response would reduce total energy demanded, which has the effect of improving reliability outcomes.

Conclusions

Despite the Commission's preliminary views that broadening the definition of unserved energy to include some or all of consumers' experiences could potentially result in significant costs, we consider that it may be worth re-examining the current definition of unserved energy given the broader changes occurring in the NEM.

For example, there has been a shift in the way the reliability standard is operationalised to be less reliant on the concept of contingencies. In particular, the Commission made a final rule in December 2017 to change the way that the lack of reserve (LOR) declaration framework works, specifically to move away from AEMO being required to declare a lack of reserve based on the concept of credible contingency events alone.[433]

In the Commission's rationale for doing so in that rule change request, we stated that it is possible for forecast and availability deviations, both on the demand and on the supply side, to be larger than the largest credible contingency, particularly on extreme weather days. These deviations are not related to credible contingency events. Therefore, the contingency-based LOR framework did not consider such deviations. It may therefore be worth assessing if the existing definition of unserved energy, which is linked to the concept of contingencies, is still appropriate.

Similarly, the current definition does not explicitly exclude all power system security events, even though in practice, it appears that this has been the case. It may be worth exploring whether the NER definition could be simplified or clarified in order to accurately reflect what is meant to be captured within unserved energy for the purposes of the reliability standard.

The Commission will review the definition of unserved energy as per Clause 3.9.3C of the NER, i.e. unserved energy in relation to the reliability standard, including seeking stakeholders' views more broadly on the existing definition.

433 This is the framework used by AEMO to operationalise the reliability standard in the short term. See https://www.aemc.gov.au/rule-changes/declaration-of-lack-of-reserve-conditions